PNG PACIFIC NORTHERN GAS

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E-File

August 21, 2024

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

File No.: 4.2.7(2024)

Attention: Patrick Wruck
Commission Secretary

Dear Patrick Wruck:

Re: Pacific Northern Gas (N.E.) Ltd.
Application for Acceptance of Expenditure Schedule for the Tumbler Ridge Gas Plant Rehabilitation Project

Accompanying, please find the application by Pacific Northern Gas (N.E.) Ltd. (PNG(NE)) to the British Columbia Utilities Commission (BCUC) for acceptance, pursuant to section 44.2(3)(a) of the *Utilities Commission Act*, of a schedule of anticipated capital expenditures in the amount of $4.92 million for the Tumbler Ridge Gas Plant (TRGP) Rehabilitation Project (Project) (Application).

The anticipated capital works to rehabilitate the TRGP outlined in the Application are planned primarily for the months of September 2024 and September 2025 and are considered crucial to providing ongoing safe and reliable natural gas service to PNG(NE)'s customers in the Tumbler Ridge service area.

Request for Confidential Treatment of Certain Appendices

PNG(NE) has filed Appendix D to the Application, the Risk Register, on a confidential basis pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents. Appendix D is an engineering document that identifies system and project risks. PNG(NE) submits that this appendix should be kept confidential as the information contained in the document is sensitive from an operational standpoint. PNG(NE) observes that it is industry standard practice for pipeline and utility operators not to provide specific detailed risk information in public forums on a non-confidential basis. PNG(NE) respectfully requests that the BCUC treat this document as confidential and to remain confidential after the regulatory process is completed.

PNG(NE) notes that parties registered as interveners and that actively participated in the regulatory proceedings to review the PNG(NE) 2023-2024 Revenue Requirements Application and the Pacific Northern Gas Ltd. 2019 Consolidated Resource Plan have been copied on this Application.

Please direct any questions regarding this letter to my attention.

Yours truly,

Original on file signed by:

Verlon G. Otto

Enclosure

cc. Leigha Worth (BCPIAC) – BCOAPO (ed@bcpiac.com)
Sam Mason – RCIA (smason@midgard-consulting.com)
Bill Andrews – BCSEA (william.j.andrews01@gmail.com)
Tom Hackney – BCSEA (thomashackney658@gmail.com)

PACIFIC NORTHERN GAS (N.E.) LTD.

TUMBLER RIDGE SERVICE AREA

Application for Approval of Tumbler Ridge Gas Plant Rehabilitation Project Expenditures

August 21, 2024

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1 Application Overview

Pacific Northern Gas (N.E.) Ltd. (PNG(NE)) hereby applies to the British Columbia Utilities Commission (BCUC), pursuant to section 44.2(1)(b) of the *Utilities Commission Act* (UCA), for acceptance, pursuant to section 44.2(3)(a) of the UCA, of a schedule of anticipated capital expenditures in the amount of $4.92 million for the Tumbler Ridge Gas Plant (TRGP) Rehabilitation Project (Project) (Application) for activities planned primarily in the months of September 2024 and September 2025.

1.1 Applicant

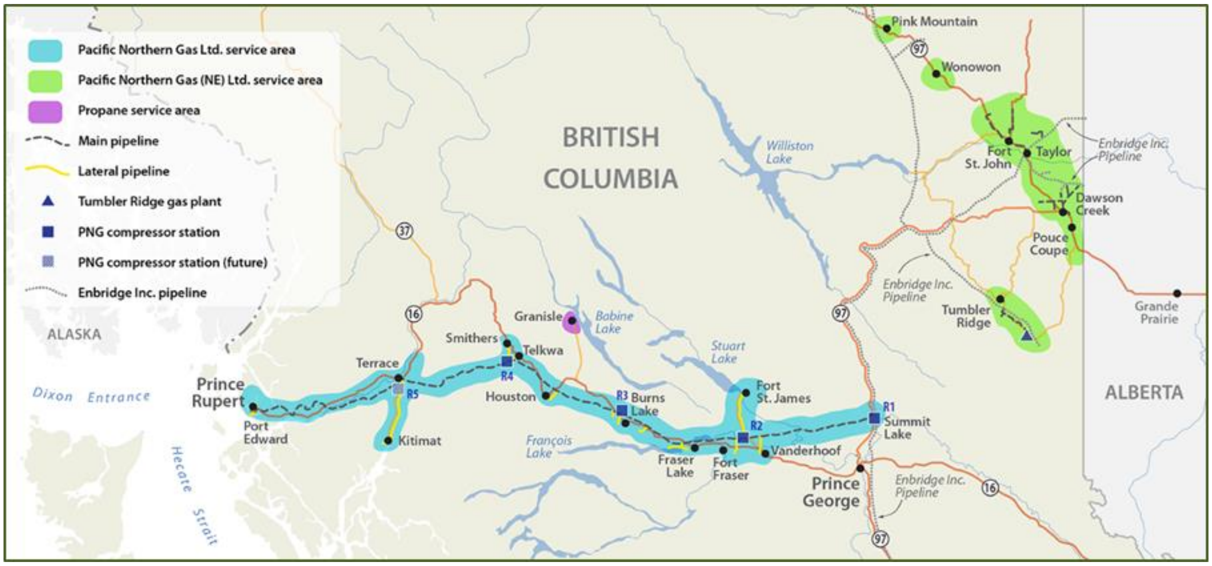
1.1.1 Background

Pacific Northern Gas (N.E.) Ltd. (PNG(NE)) is a wholly owned subsidiary of Pacific Northern Gas Ltd. (PNG). PNG(NE) owns and operates natural gas distribution systems and a gas processing plant in northeastern British Columbia and provides service to approximately 21,600 natural gas customers in the communities of Fort St. John (FSJ), Dawson Creek (DC) and Tumbler Ridge (TR).

PNG is a company formed under the laws of British Columbia and is a wholly owned subsidiary of TriSummit Utilities Inc. (TSU), the owner of several North American rate-regulated distribution, transportation and storage utility businesses and renewable power generation assets. PNG's head office is located at Suite 750, 888 Dunsmuir Street, Vancouver, British Columbia. PNG also has a western division (PNG-West) that owns and operates a natural gas transmission and distribution system in west central British Columbia. The pipeline system commences at Summit Lake, just north of Prince George, and extends west to the deep-water ports of Prince Rupert and Kitimat. PNG-West serves approximately 20,600 natural gas customers along this corridor. PNG-West also serves approximately 130 propane customers in the community of Granisle, BC.

The layout of the PNG(NE) and PNG-West transmission and distribution assets is illustrated in the figure that follows.

Figure 1-1: Overview of the PNG(NE) and PNG-West Natural Gas Pipeline Systems



1.1.2 Financial Capability

PNG(NE) is capable of financing the Project through its association with its parent company, PNG, and TSU. At this time, PNG(NE) anticipates securing debt financing for the Project from PNG and/or TSU at rates commensurate with those available in the financial markets. Morningside DBRS currently rates TSU as BBB(high) and PNG as BBB.

1.1.3 Technical Capability

Through its association with its parent company, PNG, PNG(NE) has the technical capability to coordinate and oversee the necessary remediation activities identified for the Project. PNG(NE) and PNG have many years of experience with constructing, operating and maintaining natural gas systems, including the Tumbler Ridge gas processing plant, and in providing safe and reliable gas service to its customers. In addition to the resources available internally, PNG(NE) will engage external service providers with a wide array of expertise to assist with engineering, design, procurement, project management, and construction activities.

1.1.4 Company Contact

All notices and other communications in connection with this Application should be directed to:

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Pacific Northern Gas Ltd.
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1.2 Approvals Sought and Proposed Regulatory Process

1.2.1 Approvals Sought

PNG(NE) requests, pursuant to section 44.2(3)(a) of the *Utilities Commission Act* (UCA), that the BCUC accept that the expenditure schedule for the Project (Project Expenditure Schedule), being the project cost of $4.92 million, is in the public interest. PNG(NE) notes that certain Project activities are planned for September 2024 and that expenditures related to these activities will be incurred in advance of a BCUC decision on this Application. PNG(NE) also notes that it has sought to limit the work conducted in 2024 to activities that are urgently necessary to support the ongoing safe and reliable operation of the system. A Draft Order is provided as Appendix A.

1.2.2 Regulatory Framework

PNG(NE) is filing the Project Expenditure Schedule for the Project pursuant to section 44.2(1)(b) of the UCA. The Project Expenditure Schedule can be found in Table 3-8, in Section 3.4.1. PNG(NE) is seeking an order determining that the expenditures set out in the Project Expenditure Schedule are in the public interest and accepting the Project Expenditure Schedule.

In filing the Project Expenditure Schedule, PNG(NE) has also given consideration to the BCUC's determinations in the Decision and Order G-263-20 approving the PNG(NE) 2020-2021 Revenue Requirements Application. In the Decision, the BCUC directed PNG(NE) to submit an Annual Capital Report identifying non-recurring capital projects with total costs of $500,000 or more. PNG(NE) observes that it submitted its Significant Capital Expenditure Outlook for 2024-2028 to the BCUC on May 31, 2024, which included forecast capital expenditure amounts for the Project and also a statement of PNG(NE)'s intent to file an expenditure schedule with the BCUC pursuant to section 44.2 of the UCA. The Decision also established that a threshold of $1,500,000 or above for capital projects that require a Certificate of Public Convenience and Necessity (CPCN) was reasonable and suggested that PNG(NE) consider this same threshold for section 44.2 expenditure schedule filings.

1.2.3 The Public Interest Test

As noted, PNG(NE) seeks an order determining that the expenditures set out in the Project Expenditure Schedule are in in the public interest. Section 44.2(3)(a) of the UCA provides that, subject to subsections 44.2(5), (5.1) and (6), after reviewing an expenditure schedule the BCUC must accept the Project Expenditure Schedule if it considers that making the expenditures would be in the public interest.

The UCA does not define the scope and nature of the public interest test that must be satisfied by an applicant under section 44.2(3)(a). The BCUC is obliged to consider a number of factors in its review of a section 44.2(1)(b) application and has issued the BCUC's 2015 Certificate of Public Convenience and Necessity Application Guidelines (CPCN Guidelines)[1] to assist applicants in addressing some of public interest issues in regard to large capital projects. While the CPCN Guidelines do not expressly apply to capital expenditure applications pursuant to section 44.2 of the UCA, PNG(NE) seeks to generally align with the requirements set out in the CPCN Guidelines. However, these elements do not define the scope of the public interest test. Accordingly, the public interest test is contextual, and depends on the nature of the applicant, the nature of the project, and possibly other factors.

The over-arching purpose of the Project, and the related expenditures set out in the Project Expenditure Schedule, is to cost-effectively remediate the aging processing plant assets included in the scope of the Project, and to reduce the risk of failure and the potential consequential impact to the Tumbler Ridge service area that would arise from such a failure. In this regard, PNG(NE) suggests that, in deciding whether to accept the Project Expenditure Schedule, the BCUC should consider:

1) Whether the Project enables the operation of TR Processing Plant on an ongoing basis, such that the facility can continue to safely and reliably process the

[1] The BCUC 2015 Certificate of Public Convenience and Necessity Application Guidelines are provided at https://docs.bcuc.com/documents/guidelines/2015/doc_25326_g-20-15_bcuc-2015-cpcn-guidelines.pdf.

appropriate quantity and quality of acid gas to ensure that the demand of existing customers can continue to be met; and

2) Whether there are alternatives to the Project, that will ensure the same or comparable levels of reliability of supply at materially lower cost.

PNG(NE) submits that if the BCUC concludes that the answer to the first question is “yes” and that the answer to the second question is “no”, then, subject to consideration of other required factors, the BCUC should conclude that the Project is in the public interest.

1.2.4 Proposed Regulatory Process

PNG(NE) proposes a written review process that includes provision for one round of information requests and provision for further regulatory process, which is anticipated to include final submissions by PNG(NE) and registered interveners and a reply submission by PNG(NE). The table that follows sets out a preliminary regulatory timetable for the review:

Table 1-1: Proposed Regulatory Timetable

ACTION	DATE
PNG(NE) submits Application	August 21, 2024
Notification of Application	September 11, 2024
Intervener Registration Deadline	September 27, 2024
BCUC Information Request No. 1	October 9, 2024
Intervener Information Request No. 1	October 17, 2024
PNG(NE) responds to Information Request No. 1	November 7, 2024
Further Regulatory Process	To be determined

1.3 Structure of the Application

1.3.1 BCUC Guidelines

In the absence of specific BCUC guidelines for section 44.2 applications, PNG(NE) has endeavoured to structure the Application such that it generally aligns with the requirements of the CPCN Guidelines. In this regard, the Application is organized into the following sections:

- *Section 2 – Project Need and Justification* establishes context for the Application and justification for the Project, including alternatives considered;

- *Section 3 – Project Description* provides a detailed description of the Project, including construction, design, resource planning and management and schedule, as well as setting out the cost estimate, the assumptions upon which the financial analysis is based and the rate impacts;
- *Section 4 – Project Risks and Risk Mitigations* provides an overview of identified project risks and PNG(NE)'s plans to mitigate those risks; and
- *Section 5 – Consultation and Engagement* discusses PNG(NE)'s engagement and communication efforts regarding the Project.

1.3.2 Policy Considerations Including BC Government Energy Objectives

Section 44.2(3) of the UCA states that the BCUC's acceptance or rejection of an expenditure schedule is subject to subsections 44.2(5), (5.1) and (6) of the UCA. Of these considerations, subsections 44.2(5.1) and 44.2(6) do not apply to this Application as:

- Subsection 44.2(5.1) applies to expenditure schedules filed by BC Hydro [the authority]; and
- Subsection 44.2(6) addresses expenditures that were determined to be in the public interest as part of the determination that a long-term resource plan was in the public interest under section 44.1(6). None of the expenditures in the Project Expenditure Schedule were anticipated/included in the most recent PNG-PNG(NE) 2019 Consolidated Resource Plan accepted by the BCUC under Order G-265-20. On June 28, 2024, PNG submitted its 2024 Consolidated Resource Plan to the BCUC for review and acceptance. PNG observes that the works underlying the expenditures in the Project Expenditure Schedule are discussed in that submission.

As to subsection 44.2(5), the UCA provides that in deciding whether to accept an expenditure schedule, the BCUC must consider:

(a) Applicable British Columbia energy objectives;

(b) The most recent long-term resource plan filed by the public utility under section 44.1 of the UCA;

(c) The extent to which the expenditure schedule is consistent with the requirements of sections 6 and 19 of the *Clean Energy Act*;

(d) If the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any; and

(e) the interests of persons in British Columbia who receive or may receive service from the public utility.

Subsection 44.2(5)(c) does not apply to this Application because there are no prescribed targets or guidelines under Section 19 of the *Clean Energy Act*. Subsection 44.2(5)(d) does not apply to this Application as the Project Expenditure Schedule does not include demand-side measures. Subsections 44.2(5)(a), (b) and (e) are addressed in the discussion that follows.

1.3.2.1 Interest of Customers

The capital works outlined in this Application are essential to meet the needs of current and future customers of PNG(NE). Specifically, the planned investments to upgrade the TRGP are crucial for providing ongoing safe and reliable natural gas service to PNG(NE)'s customers.

1.3.2.2 British Columbia's Energy Objectives

The Province of BC's energy objectives are numerous and evolving. They include those objectives set out in the *Clean Energy Act* (CEA)[2] and are embodied in other provincial energy policies, strategies and regulations, such as Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR)[3] and the recent BC Hydrogen Strategy.[4]

The CEA contains a set of fifteen specific energy objectives for the Province of BC. It provides a guide to help the Province meet its self-sufficiency goals and to reduce GHG emissions. The CEA includes several social and economic goals for the province, including a greater focus on encouraging economic development, creating and retaining jobs, and encouraging economic development for Indigenous and rural communities through the development of clean or renewable power. The sole CEA objective which may be applicable to PNG(NE) and this

[2] See: https://www.bclaws.gov.bc.ca/civix/document/id/lc/statreg/10022_01
[3] See: https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/102_2012
[4] See: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bc_hydrogen_strategy_final.pdf

Application is CEA section 2(k), "To encourage economic development and the creation and retention of jobs." The planned rehabilitation of the TRGP will ensure that PNG(NE) is able to provide safe and reliable service to customers in the Tumbler Ridge area which will support the ongoing retention of jobs in the Tumbler Ridge area.

Further, as the Project will not result in a reduction in greenhouse gases (GHG) or make use of hydrogen, the Project cannot be considered to support these provincial strategies. Instead, this Project is important from an operational perspective – i.e. the planned investments in the TRGP are essential to provide safe and reliable natural gas service to PNG(NE)'s customers.

1.3.2.3 Most Recent Resource Plan

As previously indicated, none of the expenditures in the Project Expenditure Schedule were anticipated/included in the 2019 Consolidated Resource Plan accepted by the BCUC under Order G-265-20. PNG submitted its 2024 Consolidated Resource Plan for the BCUC's consideration on June 28, 2024. In that submission PNG has identified that a number of operational issues at the TRGP must be addressed in 2024 and 2025 to ensure the ongoing safe and reliable processing of natural gas, and that this Application would be submitted seeking BCUC approval of the Project Expenditure Schedule.

2 Project Need and Justification

2.1 Introduction

In recent years, the TRGP has exhibited operating issues that present safety and reliability risks. PNG(NE) undertook an analysis of a number of options to consider whether repairing the TRGP was the correct course of action. This included considering whether there would be a sustained supply of natural gas of suitable quality for processing at the TRGP. PNG(NE) has determined that repairing the TRGP is the preferred alternative for the reasons set out below.

2.2 Project Alternatives

During 2023 and 2024, PNG(NE) undertook the Tumbler Ridge Supply Study (Study) to evaluate gas supply alternatives to ensure ongoing safe and reliable gas supply to Tumbler Ridge customers. Alternatives identified for evaluation in the Study included: continuing to supply gas through the TRGP; converting the supply to portable compressed natural gas (CNG) or liquified natural gas (LNG) supply (virtual pipeline) and bypassing the TRGP; and building a new pipeline to bring in sweet gas from a producer and bypassing the TRGP. The Study compared the capital and operating costs of the various alternatives, as well as other important considerations such as feasibility, security of supply, and operational and construction requirements. The Study findings are presented in Appendix B – Tumbler Ridge Supply Study Summary Report.

The Project outlined in this Application follows the Study's recommendation to repair the TRGP while continuing annual operating and maintenance.

2.3 Overview of the Tumbler Ridge Gas Plant

Figure 2-1 that follows illustrates the layout of the Tumbler Ridge processing and transmission assets in proximity to major customer sites, including the Town of Tumbler Ridge, CNRL and the Quintette Mine. Figure 2-2 provides an aerial image of the TRGP assets and Figure 2.3 depicts a simplified process flow diagram for the TRGP.

Figure 2-1: Tumbler Ridge Gas Processing Plant and Transmission System

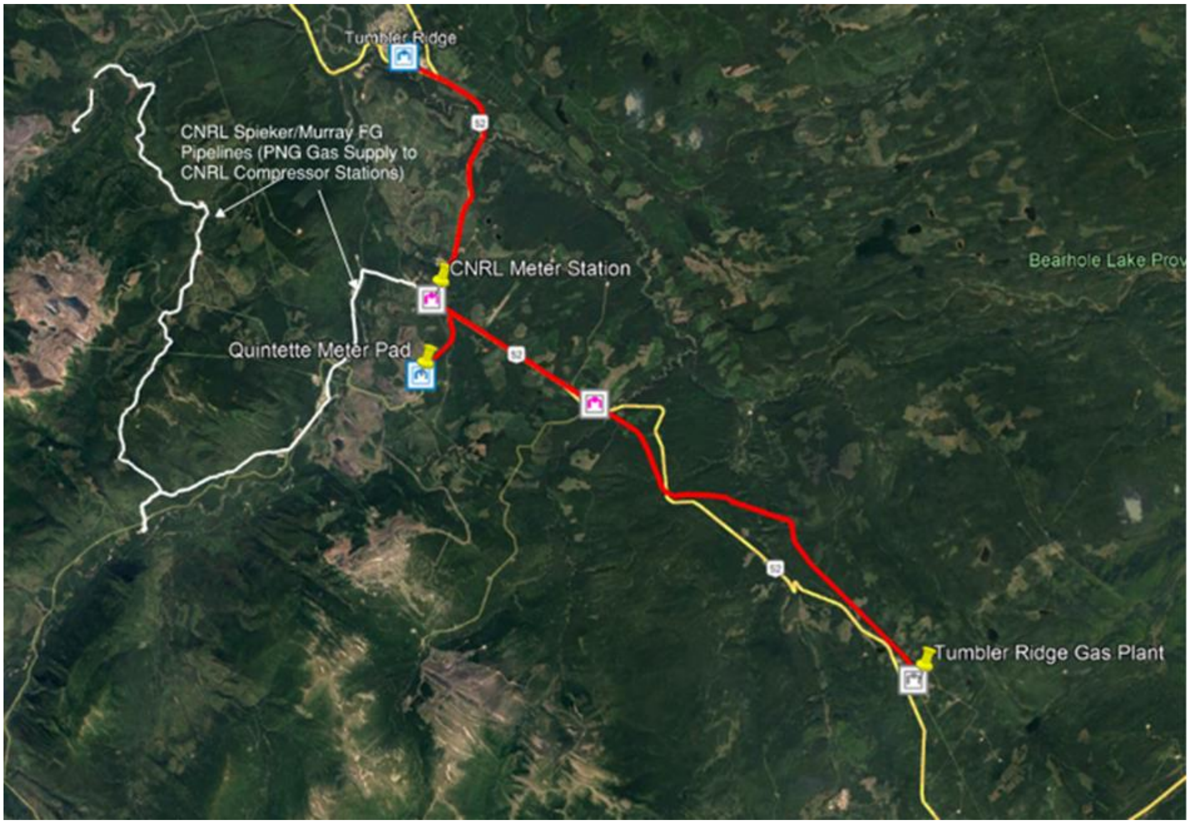


Figure 2-2: Aerial View of Tumbler Ridge Gas Processing Plant

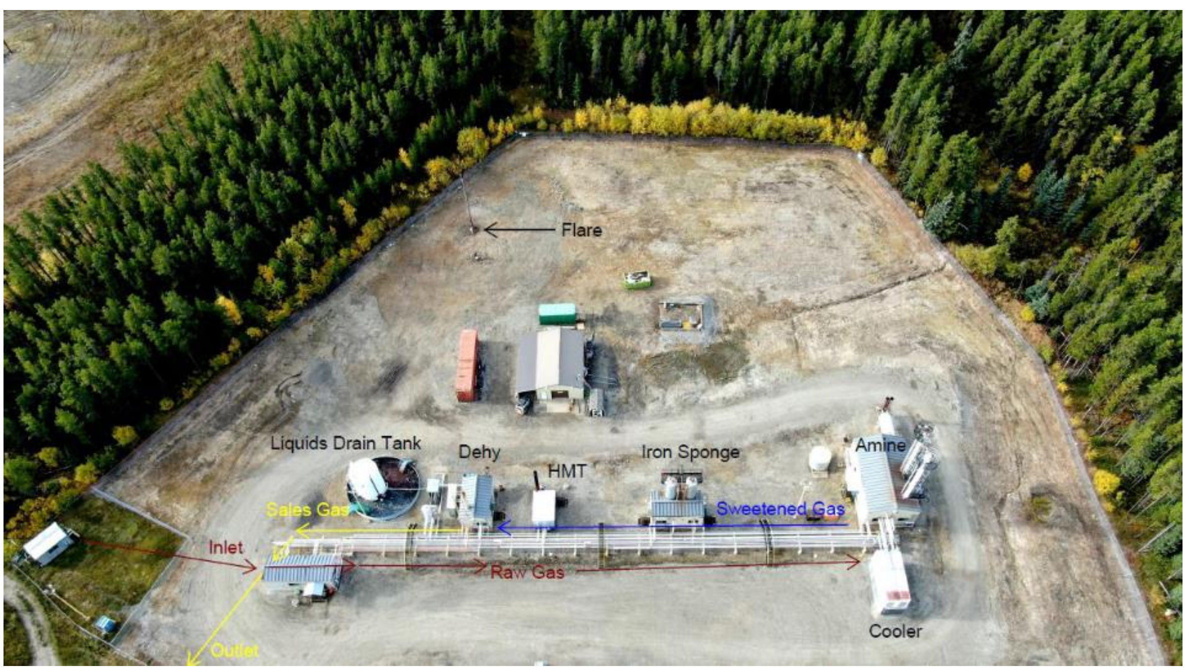
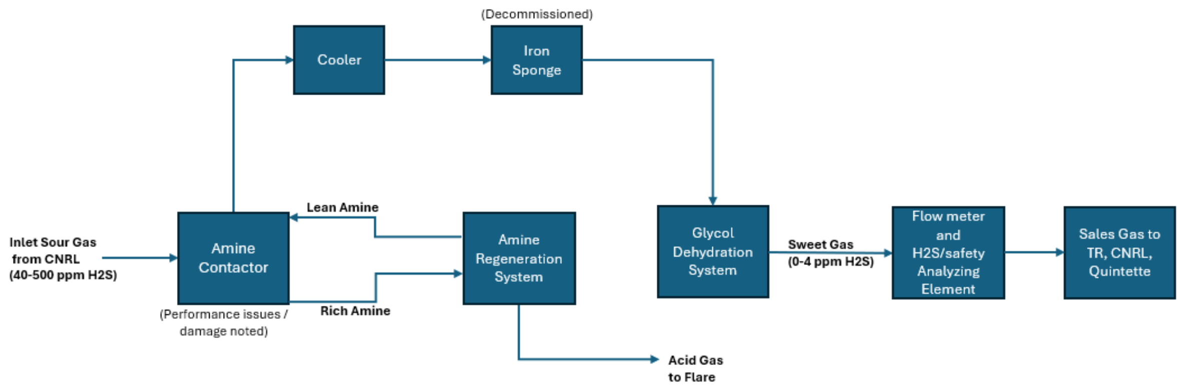


Figure 2-3: Tumbler Ridge Gas Processing Plant Flow Diagram



In general, the plant is comprised of the following components:

- Inlet: Raw Gas
  - Raw gas sourced from CNRL's gas fields is received in the inlet gas piping. Raw gas includes acid gas (H_2S and CO_2) contaminants that must be removed.
- Amine Contactor:
  - A pressure vessel containing a number of horizontal "trays" that allows intimate contact between downward flowing amine chemical and upwards flowing raw gas for removal of the acid gas contaminants in the raw gas.
- Amine Regeneration:
  - A pressure vessel containing a number of horizontal "trays" that allows for the stripping of the acid gases from the downwards flowing contaminated amine chemical thereby liberating the acid gases. The acid gases are liberated or "stripped" from the amine by upwards flowing steam vapour. The acid gases are then sent to a flare and incinerated. The amine is recycled in the closed loop system and sent back to the amine contactor to continue the sweetening process.
- Flare:
  - A continuous burning of the acid gases removed from the amine regenerator through a vertical flare.

- Cooler: Output - Sweetened Gas
  - Two coolers are integrated into a single module, these include the amine cooler which pre-cools amine prior to the contactor and the regenerator overhead gas condenser which condenses water (reflux) out of the acid gas stream.
- Iron Sponge:
  - A decommissioned H_2S removal polishing process. PNG(NE) does not presently operate this process due to the complexities and operating costs of this particular process.
- Heat Medium System (Glycol):
  - A closed loop ethylene glycol heating system that provides process heat to the regenerator (stripping steam) and building heat.
- Glycol Dehydration: Output - Sales Gas
  - Water vapor is removed from the sweetened gas in the dehydration unit to meet specifications for plant sales gas water content.
- Outlet:
  - Sales gas outlet includes flow measurement and an H_2S analyser to ensure sales gas is within specifications.

2.4 Project Need

The TRGP infrastructure is aged and subject to increasing costs for maintenance and capital improvement to ensure regulatory compliance and safe and reliable operation. Risks have arisen from age-related deterioration and potential failure of key plant equipment, including damage to the amine contactor vessel (a key piece of process equipment), and deficiencies in original design.

From 2021 to early 2023, PNG(NE) was undertaking an internal review of the TRGP to determine deficiencies and required additional inspections and repairs. In 2023, PNG(NE) engaged various third parties to support the consideration of the various options for scoping and addressing the identified deficiencies and maintenance requirements. The reviews covered a number of areas, including industrial equipment process safety, hazard and operability analysis, acid gas plant operation standards, consideration of available raw gas supplies, and structured options analysis.

These reviews focused on the following:

- Assessing the current and future natural gas supply needs of the Tumbler Ridge area, specifically the needs of PNG(NE)'s industrial, commercial, and residential customers (PNG, Lauren Services).
- Assessing the current condition of, and identifying appropriate solutions to, damaged and deteriorated TRGP equipment that are affecting the gas processing capacity and reliability of service (S2F, Solaris Management Consultants, Lauren Services).
- Identifying and assessing feasible alternatives to the status quo to ensure long-term gas supply to PNG(NE)'s customer base (PNG, Lauren Services, Solaris Management Consultants, S2F, Roy Northern, Vector Geomatics).

Key findings from these reviews include:

- The plant is currently unreliable, resulting in frequent operational upsets.
- Current plant conditions and configuration pose significant process safety risks.
- Process system damage and deterioration has significantly reduced the plant's processing capacity to levels significantly below the plant's original design capacity and insufficient for PNG(NE)'s operational and business needs. Specifically, TRGP is currently limited to approximately 40% of its original design processing capacity and to less than 10% of its original acid gas design processing capacity.

Remediation of the identified deficiencies is required to ensure safe and uninterrupted service to PNG(NE) customers.

2.5 Project Summary

PNG(NE) has established a two-phase plan to address the identified deficiencies. The two-year plan will be executed in 2024 and 2025, as follows:

- 2024 Required Inspection, Maintenance and Repair Activities:
  - Past due inspections on amine and dehydrator vessels, amine and dehydrator reboiler, and reflux piping– including external non-destructive examination (NDE)

assessments of vessels in 2024. Internal inspections of these vessels will be done in 2025.

- As-building of key engineering drawings (Process and Instrumentation Diagrams (P&ID’s) and Shut Down Keys) that are critical to the safe and reliable operation of the facility.
- Repairs to deteriorated assets to address immediate operational, safety and reliability risks.
- Assessment of plant piping wall thickness to identify any deterioration due to corrosion and, if so, determine priority repair items and those that can safely be deferred to 2025.
- Repair of amine reflux pumps and upsizing of reflux piping – the amine reflux system is currently unreliable and contributes to winter shutdowns of the plant, impacts to customers and it presents safety risks to plant operation.
- Replacement of missing and malfunctioning gauges and instruments.

- 2025 Required Inspection, Maintenance and Repair Activities:
  - Install new flare pilot metering per BCER Flare and Venting Guideline.
  - Flare stack blackened area maintenance per BCER Flare and Venting Guideline.
  - Complete pipeline isolation and blinding locations to enable ongoing safe isolation of facility for maintenance purposes.
  - Install new H_2S gas analyzer to ensure safe and reliable gas sweetening (H_2S removal) operations.
  - Install new dew point analyzer on outlet of plant to ensure plant product gas meets pipeline water dew point specifications.
  - Installation of a outlet gas filter to ensure that any liquids carryover is captured and does not adversely affect the integrity of the transmission pipeline.

- Blanket gas on the make-up water tank to limit corrosion and the filters to ensure safety during filter change-outs.
- Verification of control system shutdown actions and programming to improve plant performance during surge events.
- Piping upgrades to address equipment isolation issues and safety concerns.
- Replacement of piping segments with significant wall loss. Scope to be confirmed during 2024 inspection work.
- Operational improvements to the amine cooler and installation of an H2S detector to warn operators of gas leaks at cooler.
- Internal inspection of vessels.
- Replace damaged amine contactor vessel to restore plant sweetening capability and the capacity of the plant to ensure customer gas requirements can be met.

In the planning for work to be completed in 2024 and 2025, PNG(NE) has obtained the support of its gas supplier, CNRL, to minimize the acid gas composition of the TRGP feed gas to ensure safe and reliable operation of the TRGP until such time that all repairs and maintenance are completed in 2025.

2.6 Project Benefits

The primary benefits of the Project include:

- Addressing risks that have been identified at the TRGP;
- Resolving identified issues to allow for ongoing safe and reliable service to PNG(NE)'s customers with PNG(NE)'s existing assets; and
- Most reasonable rate impacts compared to other long-term solutions.

3 Project Description

3.1 Introduction

As discussed above, the TRGP currently exhibits considerable operational difficulties that present risks in the ongoing operation of the TRGP. From 2021 through 2023, PNG(NE) conducted several technical reviews of the performance and condition of the TRGP for the purpose of addressing safety, reliability and processing capacity related problems with the facility. With assistance from third-party technical services providers, these technical reviews focused on the following:

- Process Safety – conducted a HAZOP (Hazard and Operability) analysis of TRGP equipment and operations processes to identify process safety and operability risks. The analysis identified solutions to restore process safety to acceptable levels.
- Reliability – conducted studies of the TRGP equipment, equipment integrity and operations processes that have been negatively impacting TRGP reliability, processing capacity and its customers. The studies identified solutions to restore plant reliability, equipment integrity and processing capacity in order to meet current and future operations and business requirements.

Based on the findings of the technical reviews, PNG(NE) has determined that the TRGP requires significant repair work to ensure it is able to continue to safely and reliably operate. The TRGP is currently limited to approximately 40% of its original design processing capacity and to less than 10% of its original acid gas design processing capacity. The planned repairs and reinforcement are a cost-effective solution to restore the processing plant to a capacity that ensures reliable gas service to meet PNG(NE) customer requirements.

3.2 Project Scope

As indicated, PNG(NE) has planned to execute the TRGP maintenance work in two phases. The first phase will address critical repairs to the TRGP and is planned to be completed during the scheduled 2024 TRGP turnaround to mitigate risks of an immediate nature. The scheduled turnaround is expected to be completed between September 4 and 14, 2024. This turnaround is timed to coincide with CNRL's turnaround of its Murray River operations to minimize cost impacts due to gas supply disruptions. In 2025, PNG(NE) will complete the second phase which includes the major task of replacement of the amine contactor and any additional equipment repairs or replacements that are identified during the course of inspections conducted during the 2024 turnaround.

The general scope of work planned for the 2024 and 2025 turnarounds, respectively, are summarized in the following table.

Table 3-1: Planned Works

2024 Works	2025 Works
• Address HAZOP and regulatory deficiencies • Repairs and upgrades to the amine reflux system • Integrity inspections of plant piping • External integrity inspections of reboilers, boiler, pressure vessels and above ground tanks • Any priority repairs or replacements if found during above referenced inspections	• Replacement of amine contactor tower • Replacement or repair of amine pumps • Amine cooler repairs and upgrades • Completion of all equipment and vessel inspections including vessel internal inspections • All other equipment repairs and replacements identified in the 2024 turnaround

3.3 Basis of Design, Engineering and Cost Estimate

In support of the option to repair the TRGP and to address the problem of the damaged amine contactor, PNG(NE) engaged Solaris Management Consultants Inc. (SMCI). SMCI worked closely with PNG(NE) and conducted detailed process engineering work to determine i) current and future gas processing requirements at TRGP, and ii) a cost-effective solution to repair the amine contactor or to replace the same with a new one that is sized and configured for expected future processing requirements.

As a result, SMCI re-designed the amine contactor and specified a cost-effective replacement for the same, that will be purchased and installed in 2025. Additionally, SMCI revised the amine sweetening process design basis relative to the original (1983) design basis. The rationale for the change in amine sweetening design basis are as follows:

- Reductions to the gas flowrate relative to original design.
- Reductions to the normal operating pressure relative to original design.

Table 3-2 below outlines the changes to the plant design basis.

Table 3-2: Plant Design Conditions – Original and Planned Design Basis

		Original Process Design Basis			Planned Process Design Basis		
	Units	**Min**	**Normal**	**Max**	**Min**	**Normal**	**Max**
Raw Gas In[1]	MMSCFD (e^3m^3/d)	2 (56.6)	9.1 (257)	9.1 (257.4)	1 (28.3)	3 (84.8)	5.5 (155)
Raw Gas H_2S Content	ppm	40	500	500	40	75	500
Operating Pressure	kPa	5500	7585	7585	4750	6200	6800
Temp	deg ^{o}C	4	18	49	2	16	25
[1] Raw gas supplied by CNRL							

Table 3-3 below describes specifications for the sales gas product from TRGP; all gas processed by the TRGP must meet these requirements prior to entering the sweet gas transmission system for delivery to customers.

Table 3-3: Plant Design Conditions – Sale Gas Specifications

Property	Specification
SO_2 (Flare Emissions)	Less than 2 tonne/day
H_2S	4 ppm max
CO_2	5.4% or less, maintain min HV of 36 MJ/M3
H_2O	Less than 4 lbs/MMscf, 64.1 mg/M^3
Temperature	Max 49 °C

In addition to the aforementioned design changes to the amine system, PNG(NE) engaged S2F Global Resources Inc. (S2F) to develop detailed scope and Class 3 cost estimates for the repairs, upgrades, inspections and equipment replacements contemplated for the 2024 and 2025 turnarounds, respectively.

The cost estimates for the 2024 and 2025 turnarounds are provided in the Basis of Estimate included as Appendix C.

3.3.1 Standards and Specifications

The design and remediation of the plant will be in accordance with the *Oil and Gas Activities Act* and will meet the requirements of CSA Z662:23 (Oil and Gas Pipeline Systems (2023)), ASME B31.3, applicable internal standard practice instructions and other standards and codes referenced herein and summarized in the table that follows.

Table 3-4: Applicable Standards and Guidelines

Standard	Title	Purpose / Requirement
B.C. Reg. 104/2004	Power Engineers, Boiler, Pressure Vessel and Refrigeration Safety Regulation	Permit, design, and operational requirements for all boilers, pressure vessels, and pressure piping.
ASME B31.3	Process Piping	Prescribes requirements for materials and components, design, fabrication, assembly, erection, examination, inspection, and testing of piping.
ASME Section IX	Welding and Brazing Requirements	Segment of the ASME Boiler and Pressure Vessel Code that comprises regulations governing the qualification of welding procedures and welders.
ASME Section VIII	Rules for the Construction of Pressure Vessels, Divisions 1, 2, and 3	Comprehensive set of regulations and guidelines for the design, construction, inspection, and testing of pressure vessels.
API 510	Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair and Alteration	Addresses aspects such as inspection procedures, personnel qualifications, and requirements for pressure vessels.
API 570	Piping Inspection Code: Inspection, Repair, Alteration and Rerating of In-Service Piping Systems	Addresses the in-service inspection, repair, alteration, and rerating activities for piping systems and their associated pressure relieving devices.
B.C. Reg. 100/2004	Electrical Safety Regulation	Regulation for electrical equipment including apparatus, conduits, plant, pipes, poles, works and any other regulated product that is used, designed or intended for use for or in connection with the generation, transmission, supply, distribution, or use of electrical energy for any purpose.
CSA C22.1	Canadian Electrical Code	Applies to all electrical work and electrical equipment operating or intended to operate at all voltages in electrical installations for buildings, structures, and premises.

3.4 Project Cost Estimate, Financial Evaluation and Rate Impacts

3.4.1 Project Cost Estimate

The overall project capital cost estimate is $4.92 million. The cost estimate is supported by the Basis of Estimate prepared by Lauren and S2F (Appendix C). The project cost estimate provided by S2F contains definition levels for project scope elements to an AACE International Class 2 to Class 5 level of estimate based on the level of scope definition and information available at this time. A quantitative risk assessment was conducted for the project and the overall result for 2024-2025 indicates an expected range of accuracy of -17% to +23% which can be classified as a Class 3 estimate per AACE Recommended Practices 104R-19 and 18R-97.

PNG(NE) notes that certain project elements with an associated cost of approximately $132,000 were incorporated into the scheduled 2024 processing plant improvements totaling $297,675, as detailed in the PNG(NE) 2023-2024 Revenue Requirements Application approved by BCUC Order G-19-24.

The table that follows provides a summary of cost elements by project scope category.

Table 3-5: Project Expenditure Schedule

Cost Element ($ 000)	2024E	2025E	Total
End of Life Asset Replacement	-	$451	$451
Deteriorated Asset Repair	128	197	325
Operational Compliance Upgrades	-	467	467
Critical Safety and Reliability Improvements	18	63	81
Integrity Management Plan Requirements	50	156	206
Hazop Close-out	39	110	149
Plant Outage Activities	249	662	912
Engineering	30	290	320
Project and Construction Management	90	140	230
Turnaround Planning	86	147	232
PST	1	46	47
Total Costs before Contingency	691	2,729	3,373
Contingency	317	1,181	1,497
Total Capital Cost Estimate	**$1,008**	**$3,909**	**$4,917**

	2024E	2025E	Total
O&M	$53	$34	$87
O&M Contingency	10	12	22
Total O&M Cost Estimate	**$63**	**$46**	**$109**

The cost estimate includes PST on materials and a 46% contingency for work conducted in 2024 and a 44% contingency in 2025, reflective of the scope and elements that can only be known once the work is being conducted (see Section 3.4.1.1).

In addition to the capital costs, PNG(NE) has estimated operating and maintenance costs associated with the Project to be $63,000 and $46,000 in 2024 and 2025, respectively.

3.4.1.1 Quantitative Risk Analysis and Project Contingency

Risk identification, quantitation, and response selection have been performed with guidance from the AACE International Total Cost Management Framework and Recommended Practices 41r-08, 57r-09, and 63r-11. To develop a comprehensive project quantitative risk analysis, PNG(NE) identified potential project risks, their probability of occurrence, and impact to the Project. Lauren Services was engaged to facilitate the process and to develop a risk model in @Risk software in order to complete a stochastic (Monte Carlo) analysis. The range of minimum, most likely, and maximum probabilistic costs were modelled as a Trigen distribution to reflect the 10% to 90% confidence ranges.

For this project, PNG(NE) has selected a P90 (90%) confidence level. P90 was selected primarily to reflect the high level of uncertainty associated with the found work due to the vessel and piping inspections. The results of the analysis support the contingency provision contained in the project cost estimate. Based on the analysis, the P90 contingency is 46% for 2024 and 44% for 2025. The level of contingency reflects the uncertainty of the degree of found cleaning, repair and replacement work that could be identified during the course of equipment inspections. A contingency of this magnitude is appropriate given, i) the potential for corrosion of equipment due to the presence of acid gases in the TRGP feed; ii) the potential for corrosion products and other deleterious materials residing in the equipment due to corrosivity of such acid gases; and iii) currently undetected wear and tear on such equipment as a result of the age of the facility.

3.4.1.2 Capitalization of Costs and Depreciation

The Project proposes to undertake repairs and replacements during scheduled plant outages in each of 2024 and 2025 years. The Project will consist of multiple discrete undertakings on the TRGP during the scheduled outages and given that the TRGP will return to service before the end of each year, the capital spent is expected to be placed into service in the year the undertaking is completed. Consequently, PNG(NE) will transfer the associated capital costs of the work conducted into PNG(NE)'s rate base for the year the asset is placed into service, in accordance with PNG(NE)'s established practice for capital projects undertaken and completed within a calendar year. Also in accordance with established practice, depreciation of project costs will commence in the year following the year the asset is placed into service.

PNG(NE) anticipates that all the capital will be placed into the BCUC Account 418 Purification Equipment account.

3.4.1.3 Net Salvage

The provision for net salvage related to project costs will be recorded to PNG(NE)'s existing Net Salvage Deferral Account in accordance with the accounting treatment established as per BCUC Orders G-164-18A and G-222-18. The net salvage provision for the Project is forecast to be approximately $1.23 million as calculated by applying the 25% net salvage rate (BCUC Account 418 Purification Equipment) on $4.92 million.

3.4.1.4 AFUDC on Capital Work in Progress

Given the nature of the Project, with multiple discrete undertakings, PNG(NE) expects that the project assets will be placed into service in the year that the capital is spent. However, if capital expenditures are carried over into a future period, in accordance with PNG(NE)'s established practice, the expenditures will attract an Allowance for Funds Used During Construction (AFUDC) at PNG(NE)'s after-tax weighted average cost of capital.

When project capital costs are placed into service and transferred to rate base, PNG(NE) will record a return on capital based on an average annual rate base at PNG(NE)'s approved return on equity. The average rate base will also incur interest expense at PNG(NE)'s cost of debt.

3.4.2 Rate Impacts

3.4.2.1 Delivery Rate Impacts

The capital cost magnitude combined with the PNG(NE) Tumbler Ridge service area's limited customer base will have a material rate impact. On a standalone basis, PNG(NE) anticipates that the Project will increase the total cost of service to Tumbler Ridge customers by approximately 25% in 2026 once fully implemented. PNG(NE) has undertaken a financial analysis of the Project over a 3-year period. Table 3-5 that follows provides the summary of the analysis.

Table 3-6: Summary Financial Analysis

Cost of Service Calculation	2024E	2025E	2026E
Depreciation of utility plant	-	28,786	140,485
Tax on depreciation	-	10,647	51,960
Amortization of negative salvage value	-	7,196	35,121
Tax on Amortization of negative salvage value	-	2,662	12,990
Interest on utility plant	13,713	80,014	130,262
Return on equity on utility plant	22,253	130,062	211,739
Tax on return on equity	8,231	48,105	78,315
C.C.A. tax reduction	(35,387)	(53,848)	(43,078)
O&M	63,389	45,544	
Total Cost of Service	**72,199**	**299,169**	**617,794**

The anticipated average rate impacts for residential customers arising from the forecast increase in cost of service is illustrated in Table 3-6 below. As shown for 2026, Tumbler Ridge residential customers would see a basic charge and delivery charge increase of approximately $2.51/month and $3.38/GJ, respectively, relative to rates approved and in place for 2024, which is equivalent to an annual bill increase of approximately $277.

Table 3-7: Illustrative Basic Charge and Delivery Charge Rate Impacts of the Project

Residential Rate Impact	2024	2025	2026
2024 Cost of Service (Decision RRA) Less Rate Smoothing	$2,456,106	$2,456,106	$2,456,106
Incremental Project Cost Of Service	$72,199	$299,169	$617,794
Percentage Increase to 2024 COS	2.9%	12.2%	25.2%
2024 Delivery Rate (incl. Co. use gas)/GJ	$13.44	$13.44	$13.44
2024 Basic Charge (monthly)	$9.96	$9.96	$9.96
Estimated Rate Impact			
Delivery Charge ($/GJ)	$0.40	$1.64	$3.38
Basic Charge ($/Month)	0.29	1.21	2.51
Total rate Impact ($/GJ)	**$0.44**	**$1.84**	**$3.79**
Annual Bill Impact			
2024 Estimated Usage per Account (GJ)	73.0	73.0	73.0
Annual Impact			
Basic Charge	$3.51	$14.56	$30.06
Delivery Charge	$28.84	$119.51	$246.79
Total	**$32.35**	**$134.06**	**$276.85**

3.4.2.2 Impacts of Planned Cost of Service Allocation Changes

PNG(NE) is presently in the process of completing a cost of service study, with a view to propose certain rate rebalancing measures to be effective January 1, 2026, in the forthcoming 2025-2026 RRA. PNG(NE) anticipates that the rate impacts for residential customers identified in Section 3.4.2.1 will be partially mitigated by the rate rebalancing work; however, PNG(NE) does not have the specific analysis completed to provide a more certain estimate at this time.

PNG(NE) also anticipates seeking BCUC approval for the reclassification of the cost of service associated with the TRGP from an element of the cost of service underpinning basic charge and delivery charge changes to an element of the consolidated commodity-related costs.

If approved, the TRGP cost of service would be reclassified to commodity costs as an element of the consolidated commodity-related demand charges. Similar to the gas storage and transportation costs presently classified as demand charges, the TRGP cost of service (gas processing costs) are midstream costs (takes place after extraction and before distribution to end-users) typically recovered as a demand-based charge. If approved, the implementation of this change together with the impacts of rate rebalancing are expected to entirely mitigate the adverse rate impacts to Tumbler Ridge customers illustrated in Table 3-6.

As an indicative example, the reclassification of the TRGP cost of service to a commodity cost component would reduce the cost of service related to the basic and delivery charges in Tumbler Ridge by over 35% relative to the cost of service underlying the rates approved for 2024. While this favourable result for Tumbler Ridge customers will be offset in part by the adverse impact on the consolidated commodity-related demand charges applicable to all PNG service areas, including Tumbler Ridge, on a net basis, in this scenario Tumbler Ridge customers would be expected to see an estimated 30% decrease in combined basic, delivery and commodity charges with this proposed change.

3.5 Project Schedule

Project construction is planned for each of 2024 and 2025, with resumption of normal operating, maintenance and capital expenditures anticipated in 2026.

Project Pre-FEED studies have been completed and detailed design, permitting, and execution planning are in various degrees of development. Long-lead equipment, material, and contract services procurement for 2025 turnaround are proposed to be undertaken in Q2 2025 following Project approval.

As noted previously, remediation activities identified for 2024 will be undertaken during the 10-day TRGP turnaround scheduled for September 4 to 14, 2024. This turnaround is essential to meet regulatory compliance requirements, including inspections and pressure safety valve calibrations Remediation activities identified for 2025 will be undertaken during the TRGP 2025 turnaround, currently anticipated for Q3 2025. The duration of the 2025 turnaround will depend, in part, on the findings from the 2024 turnaround. A project roadmap is provided in Figure 3-1. The preliminary project schedule for 2025 is based on receiving BCUC approval for the Project by March 1, 2025, with an assumed construction start in September 2025.

Figure 3-1: Project Roadmap

	2024								2025									
	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
Section 44.2																		
S44.2 Expenditure Application Development	x	x	x															
Submit 44.2 Expenditure Application				x														
BCUC Review 44.2					x	x	x	x	x	x								
Processing Plant Repairs																		
2024 TRGP Turnaround					x													
2025 Long Lead Procurement												x	x	x	x	x		
Contracting															x	x		
2025 TRGP Turnaround																	x	

As indicated in the project roadmap, it will be necessary to procure certain long-lead items required for the 2025 turnaround early in the second quarter of 2025. These items include the following: amine contactor vessel; H_2S analyzers; flare tip; control valves; terminal blocks; heat exchanger plate pack; dew point analyzer; flare fuel gas meter; and plant outlet filter. The estimated cost of these materials is approximately $0.66 million.

3.6 Project Impacts

3.6.1 Environment and Archaeology

In developing the Project, PNG(NE) has performed desktop-based overview assessments to investigate and assess the potential for environmental and archaeological impacts that may arise from the project work as applicable per alternative.

As the selected alternative has no new land requirements and all work is on existing above ground equipment, no environmental or archaeological considerations are required.

3.6.2 Socio-economic

PNG(NE) has assessed the overall impact of the Project from a socio-economic perspective and believes that the Project will have positive economic impacts to the region as the remediation works to the TRGP will allow PNG(NE) to continue to meet anticipated demand from customers in a safe and reliable manner.

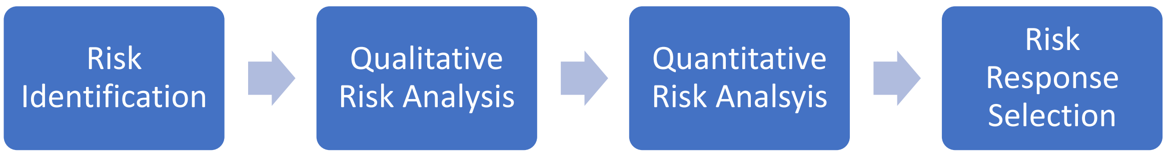
3.7 Permits Required

High-pressure pipeline segments and associated compressor and metering stations operating in British Columbia at pressures greater than or equal to 700 kPa are regulated by the BCER under the *Oil and Gas Activities Act*, Pipeline Regulation and Drilling and Production Regulations. PNG(NE) will be required to submit a Notice of Intent to the BCER for replacement in kind and maintenance activities as required by the BCER Operations Manual. Further, a BCER Amendment application will be submitted for the extended lease area for vegetation control of the flare blackened areas.).

4 Project Risks and Risk Mitigations

In general, PNG(NE)'s risk analysis for the Project was as per the process illustrated in Figure 4-1.

Figure 4-1: Project Risk Review Process



A risk register was created by S2F for each project scope element through a series of workshops where all project risks, probabilities, impacts, potential mitigations, and post-mitigation residual risks were identified. A copy of the project risk register has been included for reference as Appendix D on a confidential basis.

Table 4-1 that follows provides a summary of major identified project risks as taken from the noted risk register. These identified risks support the quantitative risk analysis described in Section 3.4.1.1.

Table 4-1: Project Risk Summary

Item	Scope Element	Risk Title	Risk Description	Mitigation Strategy
1	E - IMP Requirements	Inspection H-100 amine reboiler.	Potential found work due to excess corrosion: 1. Vessel wall thickness below acceptable limits 2. Fire tube damage due to corrosion or hot spots	1. Prepare shelf-ready welding and repair procedures for equipment if repairs are appropriate. 2a. Conduct engineering fit for service assessment based on found condition and achievable repairs. Deem the repairs temporary or permanent. 2b. Replace the reboiler shell and/or firetube in 2025 if assessment fails to extend the life of the vessel.

Item	Scope Element	Risk Title	Risk Description	Mitigation Strategy
2	E - IMP Requirements	Inspection H-101 TEG dehy reboiler.	Potential found work due to excess corrosion: 1. Vessel wall thickness below acceptable limits 2. Fire tube damage due to hot spots or corrosion	1. Prepare shelf-ready welding and repair procedures for equipment if repairs are appropriate. 2a. Conduct engineering fit for service assessment based on found condition and achievable repairs. Deem the repairs temporary or permanent. 2b. Replace the reboiler shell and/or firetube in 2025 if assessment fails to extend the life of the vessel.
3	E - IMP Requirements	Inspection H-103 HMS boiler.	Potential found work due to excess corrosion: 1. Vessel wall thickness below acceptable limits 2. Fire tube damage due to hot spots or corrosion	1. Prepare shelf-ready welding and repair procedures for equipment if repairs are appropriate. 2a. Conduct engineering fit for service assessment based on found condition and achievable repairs. Deem the repairs temporary or permanent. 2b. Replace the reboiler shell and/or firetube in 2025 if assessment fails to extend the life of the vessel.

5 Consultation and Engagement

All of the proposed remediation activities for the TRGP Project will be undertaken within the boundaries of the existing footprint of the TRGP. On this basis, PNG(NE) is of the view that no formal public consultation is required for the Project. Further comments are provided in the discussion that follows.

First Nations

With the TRGP Project activities all planned on privately-owned land (i.e. within the boundaries of existing footprint of the TRGP), PNG(NE) has assessed that a duty to consult with First Nations has not been triggered. The planned activities are intended to rehabilitate existing facilities and restore a portion of the original design capacity and do not represent a change to, or expansion of, established operations. Therefore PNG(NE) has not identified, nor does it anticipate, any issues or concerns related to First Nations.

Customers

PNG(NE) is engaged in active and ongoing discussions with its two largest customers in the Tumbler Ridge service area, CNRL and Quintette Mine, including discussions on the planned remediation of the TRGP as proposed in this Application. In 2023, the demand from these two customers accounted for approximately 86% and 1%, respectively, of the TRGP output.

- CNRL – As both the sole supplier of raw gas to TRGP and the largest consumer of TRGP's sweet gas output, CNRL plays a crucial role in the Tumbler Ridge service area. PNG(NE) has been in discussions with CNRL on the matters of gas supply (including the composition, quality and volumes of gas reserves), future demand for CNRL's Murray River operations, and the scheduling of project works to align with CNRL's own turnaround timing.

- Quintette Mine – The Quintette Mine metallurgical coal processing plant and related facilities, located near Tumbler Ridge, had been in "care and maintenance" since 2000, drawing only limited gas from PNG(NE) from its prior owner, Teck Resources. In 2023, Quintette Resources Limited Partnership (QRLP) acquired the Quintette Mine with a view to modernize the processing plant and return the facility to production. Through the winter of 2023/2024 to present day, QRLP has increased natural gas use as part of its plant modernization efforts. However, processing operations have not yet restarted. PNG(NE) has been in discussions with QRLP regarding increased permanent gas service to the Quintette Mine to support the prospective return to production. If QRLP ultimately seeks to contract for increased service, PNG(NE) considers that the refurbished TRGP will have sufficient processing capacity to serve QRLP’s requested demand.

PNG(NE) is proposing the installation of a Liquefied Natural Gas (LNG) back-up system for QRLP to mitigate the risk of any potential service interruption and to protect critical equipment until such time as the Project is complete. Should QRLP elect to proceed with LNG back-up service, PNG(NE) considers that the costs related to any such service would be dedicated to, and borne by, QRLP, similar to the arrangements implemented during winter 2023/2024 as approved by BCUC Order G-35-24.

APPENDICES

Appendix A – Draft Order

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
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TF: 1.800.663.1385

ORDER NUMBER
G-xx-25

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

Pacific Northern Gas (N.E.) Ltd.
Application for Approval of Tumbler Ridge Gas Plant Rehabilitation Project

BEFORE:
[X. X. Last Name, Panel Chair]
[X. X. Last Name, Commissioner]

on [Month Day, Year]

ORDER

WHEREAS:

A. On August 21, 2024, Pacific Northern Gas (N.E.) Ltd. (PNG(NE)) filed an application with the British Columbia Utilities Commission (BCUC), seeking acceptance of a capital expenditure schedule for costs estimated at $4.917 million for the Tumbler Ridge Gas Plant Rehabilitation Project (Project), pursuant to section 44. 2 of the *Utilities Commission Act* (UCA) (Application);

B. The Project consists of the repairs to and replacement of certain equipment at the existing gas processing plant situated in PNG(NE)'s Tumbler Ridge service area;

C. By Order [G-XX-24] the BCUC established the regulatory timetable for the review of the Application, which included one round of information requests (IRs) to PNG(NE) from the BCUC and interveners, and final and reply arguments;

D. The [Party 1] and [Party 2] registered as interveners in the proceeding; and

E. The BCUC has considered the Application, evidence and submissions of the parties and makes the following determinations.

NOW THEREFORE the BCUC orders as follows:

NOW THEREFORE pursuant to section 44.2 of the UCA, and for the reasons provided in the Decision issued concurrently with this order, the BCUC orders as follows:

1. PNG(NE)'s capital expenditure schedule for the Project, with a cost estimated at $4.917 million, is accepted.

DATED at the City of Vancouver, in the Province of British Columbia, this [XXth] day of [Month 2025].

BY ORDER

[X. X. last name]
Commissioner

Appendix B – Tumbler Ridge Supply Study Summary Report

PROJECT ALTERNATIVE ASSESSMENT AND SELECTION SUMMARY REPORT

Tumbler Ridge Gas Supply Reinforcement Study

Pacific Northern Gas (N.E.) Ltd.

Doc No: PNG002-003-0250-RPT-0001

0	Aug 14, 2024	Issued for Information	Austin Bercier	Scott Arnold	Graham Pavlik
REV	DATE	DESCRIPTION	BY	CHECKED	APPROVED

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1.0 EXECUTIVE SUMMARY

Introduction

Pacific Northern Gas (N.E.) Ltd. (PNG(NE) undertook the Tumbler Ridge Gas Supply Study to identify and assess alternatives for long term gas supply to PNG(NE)'s existing customers in the Tumbler Ridge service area. The current operation of PNG(NE)'s Tumbler Ridge system is dependent on three core components: (i) the volume and composition of raw gas supply; (ii) the capability of the Tumbler Ridge Gas Plant (TRGP) to process supplied raw gas into sales gas; and (iii) the integrity of the high-pressure transmission pipeline to transport sales gas to customers. PNG(NE) retained various external firms to perform engineering assessments to assess the capability of these core system components and to identify prospective long-term supply alternatives.

This report summarizes the results of PNG(NE)'s scoping work and alternatives assessment. Four alternatives were identified for evaluation:

- Alternative 1: Status quo (Maintain Current State – no remediation)
- Alternative 2: TRGP remediation (Remediate Plant)
- Alternative 3: LNG or CNG supply (Virtual Pipeline)
    - Includes decommissioning of the TRGP
    - Includes retaining an approximately 10.5km long segment / decommissioning the rest of the existing transmission pipeline
- Alternative 4: Construction of a new sweet gas pipeline
    - Includes decommissioning of the TRGP
    - Includes retaining an approximately 12km segment / decommissioning the rest of the existing transmission pipeline

The assessment of alternatives is complicated by factors that make a direct "apples-to-apples" comparison challenging. For instance, Alternative 2 (TRGP remediation) requires the existing gas plant remain in service whereas Alternative 3 (virtual pipeline) and Alternative 4 (new sweet gas pipeline) both assume TRGP decommissioning. Alternative 3 and Alternative 4 would require only a portion of the existing transmission pipeline to be maintained whereas Alternative 1 and Alternative 2 require the whole transmission pipeline as it exists today. Further, Alternative 3 assumes that PNG(NE) would abandon service to its existing industrial customers, being CNRL Murray River and the Quintette Mine, whereas all other alternatives maintain service to all customers. To assess these alternatives and the unique interplay between them, PNG(NE) developed criteria that consider technical, financial, operational, compliance, project execution, and customer/stakeholder inputs.

Summary of Evaluation Results

Table 1 summarizes the results of the financial evaluation of alternatives. Alternative 2 – TRGP Remediation – has the lowest cost NPV and rate impact.

Table 1 - Financial Evaluation of Alternatives

	Alternative	Description	NPV	Rate Impact (10-year average)
1	Status Quo[2]	Operate the Tumbler Ridge Gas Plant and transmission pipeline in its current state.	n.a.	n.a.
2	Tumbler Ridge Gas Plant Remediation	Addressing several critical integrity concerns related to the safety and operability of the overall plant.	$26.9MM	44%
3	Virtual Pipeline (CNG) and Decommission Plant	Establish a new gas supply via CNG. Decommission TRGP and a portion of the associated transmission pipeline.	$59.5MM	195%
	Virtual Pipeline (LNG) and Decommission Plant	Establish a new gas supply via CNG. Decommission TRGP and a portion of the associated transmission pipeline.	$33.4MM	98%
4	New Sweet Gas Pipeline and Decommission Plant	Establish a new gas supply through a new pipeline (3 routing options) to connect CNRL Bullmoose system to the CNRL Murray River System and decommission TRGP and a portion of the associated transmission pipeline.	$43.9MM - $51.4MM	134% - 150%

Table 2 summarizes the results of the alternatives evaluation scoring. Alternative 2 – TRGP Remediation has the highest weighted score.

Table 2 - Weighted Score of Alternatives (higher is best)

Weighted Score	Alternative	Alternative Description
4.21	2	Repair Plant (Recommended)
2.98	4	New Sweet Gas Pipeline and Decommission Plant – Path B
2.70	4	New Sweet Gas Pipeline and Decommission Plant – Path C
Not Scored	1	Status Quo
Not Scored	3	Virtual Pipeline
Not Scored	4	New Sweet Gas Pipeline and Decommission Plant – Path A

2.0 INTRODUCTION

2.1. System Overview

Pacific Northern Gas (N.E.) Ltd. (PNG(NE)) operates a dedicated system to provide natural gas service to customers in its Tumbler Ridge service area. The Tumbler Ridge system is comprised of three primary components: (1) a sour gas processing plant – the Tumbler Ridge Gas Plant; (2) a 37 km segment of high-pressure transmission (sales gas) pipeline; and (3) gate stations and distribution pipeline infrastructure. Refer to Figure 1 below. The transmission pipeline is shown in red.

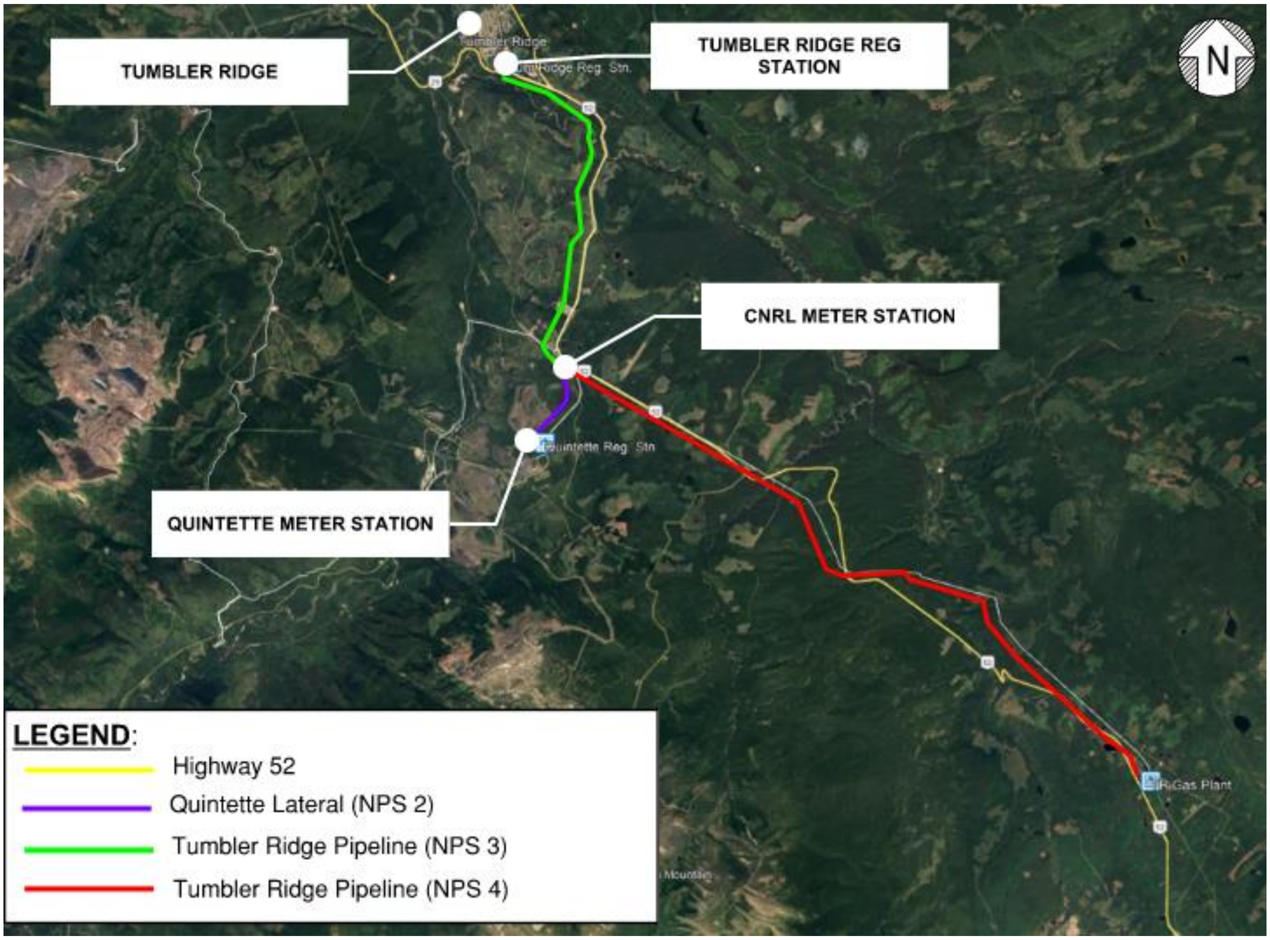

Figure 1 - Tumbler Ridge Area System

The TRGP is supplied with raw gas from Canadian Natural Resources Ltd. (CNRL). CNRL collects both sweet and sour raw gas from area gas fields though a common gas gathering system and delivers the raw gas to PNG(NE) at the TRGP inlet. The TRGP removes hydrogen sulfide (H_2S) and carbon dioxide (CO_2) from the raw gas and delivers “sweetened” pipeline quality sales gas to its customers via the transmission pipeline and associated distribution pipeline infrastructure.

CNRL is both the sole supplier of raw gas to – and the single largest consumer of sales gas from – PNG(NE)'s Tumbler Ridge system. For the prior three calendar years of 2021 through 2023, average natural gas consumption by customers on the Tumbler Ridge system was as follows:

- CNRL Murray River Operations – 82%
- Residential and commercial customers in the District of Tumbler Ridge – 17%
- Quintette Mine – 1%

2.2. Study Objective

PNG(NE) undertook the Tumbler Ridge Gas Supply Study to identify and assess alternatives for long term gas supply to PNG(NE)'s existing customers in the Tumbler Ridge service area. The current operation of PNG(NE)'s Tumbler Ridge system is dependent on three core components: (i) the sufficiency of raw gas supply volumes and sweet/sour gas composition; (ii) the capability of the TRGP to process supplied raw gas into sales gas; and (iii) the integrity of the high-pressure transmission pipeline to transport sales gas to customers. PNG(NE) retained various external firms to perform engineering assessments to assess the capability of these core system components and to identify prospective long-term supply alternatives.

This report summarizes the results of PNG(NE)'s scoping work and alternatives assessment. It also describes PNG(NE)'s evaluation methodology and results. The report is structured as follows:

- Section 2: Review of Gas Supply Alternatives
- Section 3: Transmission Line Considerations
- Section 4: Evaluation Methodology
- Section 5: Financial Evaluation and Results
- Section 6: Summary of Scoping Documents / Engineering Assessments
- Section 7: Class 3 Estimating

2.3. Methodology

Alternative Identification, assessment, and selection is generally aligned with the British Columbia Utilities Commission (BCUC) Certificate of Public Convenience Necessity (CPCN) Guidelines. Figure 2 below depicts the general methodology.

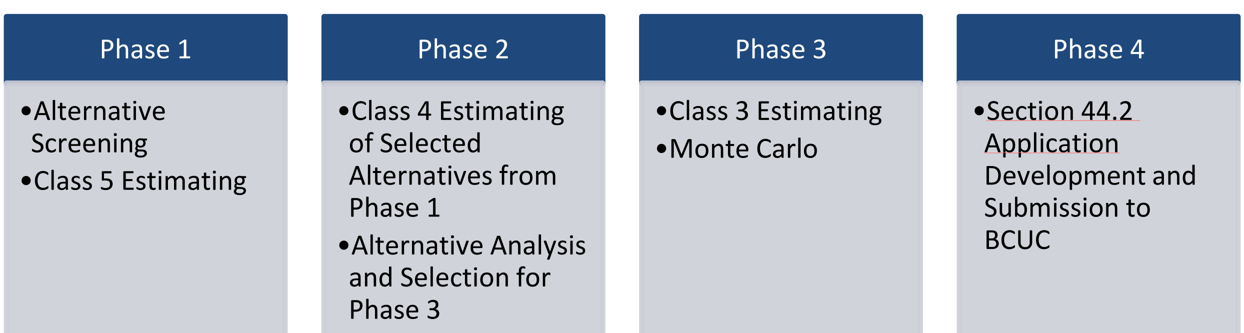

Figure 2 – Methodology

3.0 REVIEW OF GAS SUPPLY ALTERNATIVES

PNG(NE) considered several alternatives to provide for the long-term, reliable supply of natural gas to the Tumbler Ridge service area. In the initial phase of the assessment exercise, PNG(NE) considered technical viability, cost, compliance with applicable codes, standards and regulations, project timing, and the ability for the alternative to meet both the immediate and long-term capacity and service requirements for PNG(NE) customers. Table 3 provides a summary of the initial screening performed for each alternative. A detailed overview of each alternative follows with description of assessment and study work performed to date in Appendix B.

Table 3 - Project Scope Elements – Initial Screening Assessment

Scope Element	Alternatives Evaluated	Initial Screening
Status Quo (Maintain Current Status – No Remediation)	• Status quo was not considered viable due to identified TRGP processing constraints and compliance requirements	• TRGP remediation is required immediately to maintain reliable service to customers
TRGP Remediation	a) Restore design/nameplate plant processing capacity b) Restore reduced plant processing capacity	• Perform emergency repairs and compliance maintenance • Restore plant processing capacity (reduced capacity) to better match customer needs
Virtual Pipeline* ** Both virtual pipeline options assume deactivation of the TRGP, with use of 10.6km segment of existing transmission pipeline / deactivation of balance of the transmission pipeline, and abandonment of service to existing large industrial customers*	a) CNG b) LNG	• LNG is preferred alternative vs CNG due to 6:1 storage ratio and lower operating costs for trucking/delivery
New Sweet Gas Pipeline** *** Requires deactivation of TRGP, with use of 12km segment of existing transmission pipeline / decommissioning of balance of the transmission pipeline*	a) Path A b) Path B c) Path C	• Path B or C

3.1. Alternative 1 – Status Quo (Maintain Current State – No Remediation)

The Status Quo alternative is to continue to operate the TRGP and transmission pipeline without capital investment. However, PNG(NE) considers that Status Quo is not a viable alternative. Engineering assessments of the TRGP completed as part of this assessment have identified that the TRGP is damaged. This damage has caused processing constraints that require immediate attention. The TRGP is presently capable of operating at only one third of its design capacity (total volume) and is unable to process sour gas. PNG(NE) considers that TRGP remediation is required to restore reliable natural gas service to customers. Accordingly, Status Quo was assessed as not meeting PNG(NE)'s requirement for safe and reliable operations and is not considered further.

3.2. Alternative 2 – TRGP Remediation

This alternative involves addressing emergent issues related to the safe and reliable operation of the TRGP. Through a combination of internal and third party engineering assessments, PNG(NE) determined that the TRGP is damaged and currently limited to approximately 3.5 million standard cubic feet per day (MMSCFD) of processing capacity with 0 to 75 parts per million (ppm) of H_2S. This compares to the original design processing capacity of 9.1 MMSCFD and up to 500 ppm of H_2S. PNG conducted an internal evaluation to determine the reasonable and practical design (planned) design basis for the plant on a go forward basis given current and potential future capacity requirements. Refer to Table 4 below for original and planned plant capacity.

Table 4 - Original Process Design vs Planned Plant Processing Capacity

		Original Process Design Basis			Planned Process Design Basis		
	Units	**Min**	**Normal**	**Max**	**Min**	**Normal**	**Max**
Raw Gas In[1]	MMSCFD (e^3m^3/d)	2 (56.6)	9.1 (257)	9.1 (257.4)	1 (28.3)	3 (84.8)	5.5 (155)
Raw Gas H_2S Content	ppm	40	500	500	40	75	500
Operating Pressure	kPa	5500	7585	7585	4750	6200	6800
Temp	deg ºC	4	18	49	2	16	25
[1] Raw gas supplied by CNRL							

As noted above and described in more detail below, the TRGP is damaged and requires repair. PNG(NE) considers that the TRGP repair work cannot be deferred and is required to maintain reliable natural gas service to existing customers under all other prospective alternatives (i.e., given the timelines for engineering, design, permitting, approval, construction, and commissioning timelines).

3.2.1. Plant Repairs

The following is a summary of the repairs required to restore safe and reliable TRGP processing operations. The proposed TRGP remediation is not intended to restore the plant's original design capacity of 9.1 MMSCFD. Rather, the TRGP will be restored to a reduced capacity sufficient to meet PNG(NE)'s anticipated needs for safe and reliable gas service to area customers as noted in the table above.

Amine Contactor

The TRGP's processing capacity and efficiency is limited by significant damage to the amine contactor vessel. The amine contactor removes CO_2 and H_2S (Acid Gases) from raw natural gas via chemical reactions in the contactor tower. TRGP was originally designed to be capable of processing natural gas with H_2S concentrations up to 500 ppm. Engineering assessments have determined that the amine contactor tower internal trays are irreparably damaged. Due to the damaged trays, TRGP is only marginally capable of processing sufficient gas volumes to meet current winter peak system demand and it has difficulty processing H_2S at concentrations less than 50 ppm. As an interim measure, PNG(NE) has requested that CNRL shut-in all sour gas wells and, on an interim basis, provide only sweet, dry gas to the TRGP inlet until the amine contactor is replaced.

Replacement of the amine contactor tower will allow the gas plant to process sour gas at H_2S concentrations up to 500 ppm. A replacement in kind (i.e., to match existing design capacity) was assessed in parallel with assessment of a smaller amine unit. The assessment determined that an amine contactor tower with reduced capacity compared to the original nameplate, but still sized large enough to meet existing and forecast customer needs, will be a more cost-effective and lower risk solution.

Amine / Acid Gas Coolers

The present amine cooler configuration is contributing to operational upsets at the plant. In the current setup, there are two separate process streams (lean amine and acid gases) which are being cooled by only one set of fans and controls. However, each separate process stream has different operating target temperatures and cooling requirements to stay within acceptable process parameters. Under the current system configuration the temperatures for each process stream cannot be properly controlled. Accordingly, the amine cooler is constantly in an unstable state. PNG(NE) plans to perform an inspection of the cooler, fans, and process controls during the planned September 2024 turnaround. This inspection will confirm the required repairs and/or modifications to ensure reliable operation of the amine cooling system.

Compliance Repairs and Inspections

Scope items for compliance inspections and repairs currently scheduled for PNG(NE)'s September 2024 maintenance outage are listed below:

- Past due inspections on amine and dehydrator, amine and dehydrator reboiler, and reflux piping– including external non-destructive examination (NDE) assessments of vessels in 2024. Internal inspections of these vessels will be done in 2025.
- As-building of key engineering drawings (Process and Instrumentation Diagrams (P&ID's) and Shut Down Keys) that are critical to the safe and reliable operation of the facility.
- Repairs to deteriorated assets to address immediate operational, safety and reliability risks.
- Assessment of plant piping wall thickness to identify any deterioration due to corrosion and, if so, determine priority repair items and those that can safely be deferred to 2025.
- Repair of amine reflux pumps and upsizing of reflux piping – the amine reflux system is currently unreliable and contributes to winter shutdowns of the plant resulting in impacts to customers and it presents safety risks to plant operation.
- Replacement of missing and malfunctioning gauges and instruments.

Additional scope items for inspections and repairs – currently scheduled to be completed in 2025 – are listed below:

- Equipment Inspections
- Instal new flare pilot metering per BCER Flare and Venting Guideline
- Flare stack blackened area maintenance per BCER Flare and Venting Guideline
- Complete Pipeline isolation and blinding locations to enable ongoing safe isolation of facility for maintenance purposes
- Install new H_2S gas analyzer to ensure safe and reliable gas sweetening (H_2S removal) operations

- Install new dew point analyzer on outlet of plant to ensure plant product gas meets pipeline water dew point specifications
- Replace damaged amine contactor vessel to restore plant sweetening capability and the capacity of the plant to ensure customer gas requirements can be met
- Installation of an outlet gas filter to ensure that any liquids carryover is captured and does not adversely affect the integrity of the transmission pipeline
- Blanket gas on the make-up water tank to limit corrosion and the filters to ensure safety during filter change-outs
- Verification of control system shutdown actions and programming to improve plant performance during surge events
- Piping upgrades to address equipment isolation issues and safety concerns
- Replacement of piping segments with significant wall loss. Scope to be confirmed during 2024 inspection work
- Operational improvements to the amine cooler and installation of an H2S detector to warn operators of gas leaks at cooler
- Internal inspection of vessels
- Complete repairs or replacements identified during the 2024 maintenance inspections

3.3. Alternative 3 - Virtual Pipeline (CNG or LNG)

The virtual pipeline (whether CNG or LNG) involves establishing a new gas supply via a “virtual pipeline” that includes CNG/LNG manufacture, transport vehicles, gas storage, vaporization, injection, pressure regulation, metering, and monitoring equipment. An approximately 10.5 km portion of the existing transmission pipeline system would remain in place to service remaining customers. The TRGP and remaining transmission pipeline would be decommissioned. The concept for Alternative 3 is that only residential and commercial customers in the town of Tumbler Ridge and the Tumbler Ridge Industrial Park would continue to receive natural gas service. Service to existing large industrial customers would be abandoned.

Decommissioning of the TRGP and transmission pipeline segment includes the following scope:

- Permitting and Stakeholder Engagement
- Remediation
- Decommissioning, Demolition, and Disposal
- Reclamation

The virtual pipeline would be achieved via transport of CNG or LNG from Dawson Creek to Tumbler Ridge, or other LNG supply location (as applicable), and would include the following scope components:

- Compressor Station (for CNG)
- Access to Liquefaction facility (for LNG) (Supply from Dawson, Fort Nelson, Elmworth, Tilbury, etc.)
- Delivery (trucking/trailers)
- Storage, Regasification, Pressure Control, Injection

- Power, metering, SCADA equipment

3.4. Alternative 4 - New Sweet Gas Supply Pipeline

This alternative involves construction of a new sweet gas pipeline to CNRL's Bullmoose system near Tumbler Ridge. Three prospective routes were assessed for the new pipeline: New Pipeline Path A (29 km); New Pipeline Path B (43 km); and New Pipeline Path C (39 km). Refer to Figure 2 below.

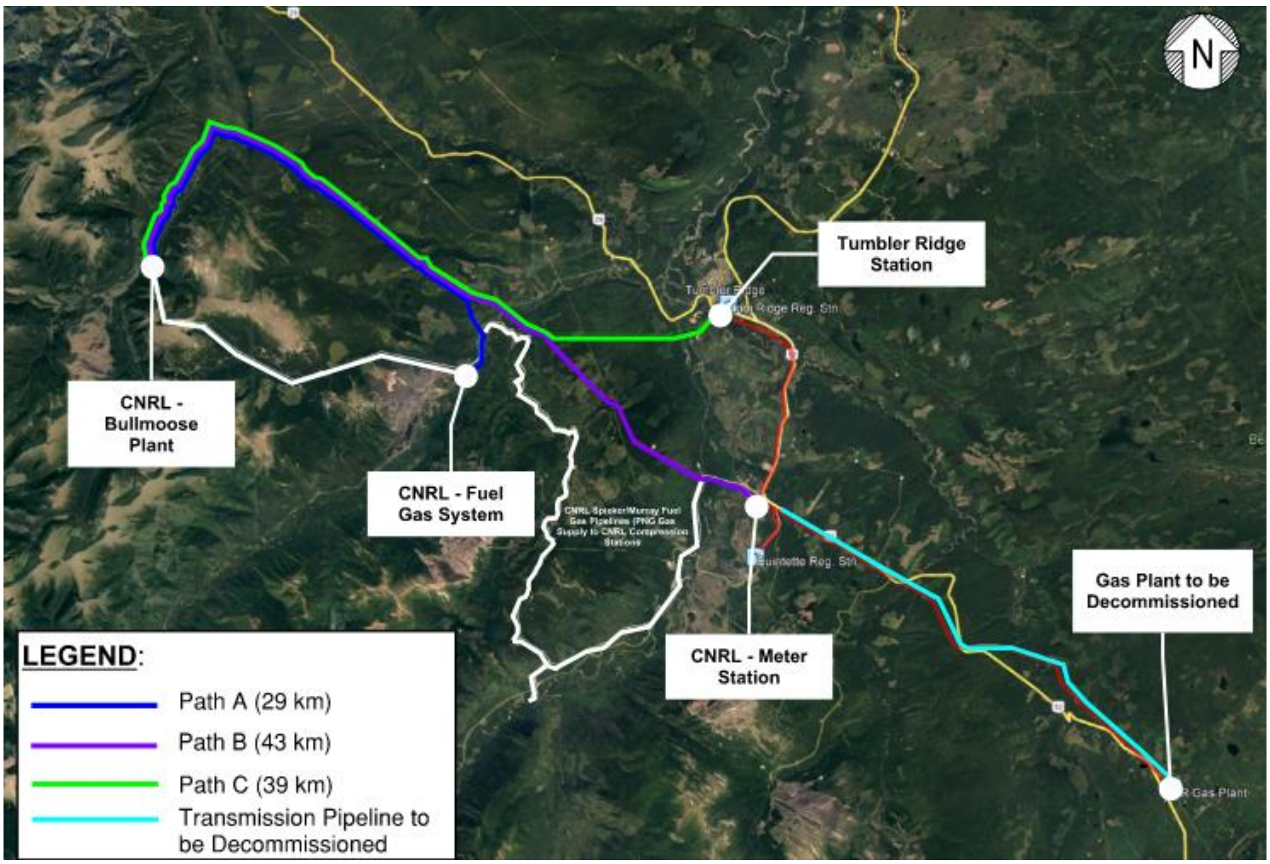

Figure 3 - Mapping of Pipeline Routing Alternatives

Alternative 4 includes decommissioning of the TRGP as well as a portion of the existing transmission line. However, an approximately 12 km portion of the existing transmission pipeline system would be maintained. Decommissioning of the TRGP – and the segment of transmission pipeline not required – includes the following scope items:

- Permitting and Stakeholder Engagement
- Remediation
- Decommissioning, Demolition, and Disposal
- Reclamation

3.4.1. Pipeline Routing Alternatives

Table 6 below summarizes the three pipeline alternatives considered, including a high-level summary of the pros and cons of each route.

Table 5 - New Gas Supply Alternatives

Item	Path A	Path B	Path C
Length	29 km	43 km	39 km
Mapping Route (see Figure 3)	Blue	Purple	Green
Route Description	• Connects the CNRL Bullmoose system to the CNRL Murray River System • PNG(NE) would buy sales gas from CNRL at the existing CNRL metering station • Requires ~18 km of upgrades to CNRL's existing 2" and 4" pipeline system as well as new compression equipment • Requires utilization of existing transmission pipeline segment from the CNRL metering station to the town and to the Quintette lateral	• Connects the CNRL Bullmoose system to the TR transmission system near the CNRL metering station • Bypasses the CNRL Murray System (CNRL pipeline and compression system upgrades not required) • Requires utilization of existing transmission pipeline segment from the CNRL metering station to the town and to the Quintette lateral	• Connects the CNRL Bullmoose system to the TR gate station • Bypasses the CNRL Murray System (CNRL pipeline and compression system upgrades not required) • Requires utilization of existing transmission pipeline segment from the town to the CNRL metering station and to the Quintette lateral
Pros	• Shortest route	• Follows existing disturbances • Bypasses CNRL system (benefit from capital cost and PNG(NE) operational independence)	• Medium length route • Bypasses CNRL system (benefit from capital cost and PNG(NE) operational independence)
Cons	• Requires CNRL pipeline and compression upgrades	• Longest route	• New disturbances (risk to permitting and construction costs)

3.4.2. Archaeological Overview Assessment

An archaeological desktop review of the three pipeline routing alternatives was performed. This review identified that all alternatives overlap with an area of modelled archaeological potential. As such, any of the potential new pipeline routes would require (at minimum):

- Archaeological Information Form for the BC Energy Regulator (BCER);
- Archaeological Impact Assessment (AIA) under Heritage Conservation Act (HCA);
- Section 12.2 Permit to BCER; and
- Indigenous engagement and consultation associated with the above.

3.4.3. Environmental Desktop Study

An Environmental Desktop Study was performed, including: BCER Area-based Analysis; Provincial and Federal Stream Crossings Assessment; Wetland Regulatory Assessment; and Regulated Wildlife Assessment. The study identified that all pipeline routes are located outside of the Agricultural Land Reserve but are located within an ‘Ungulate Winter Range’ for Caribou. This will require Caribou Reporting to the BCER and associated First Nations engagement. No mapped streams or wetlands are located within the project area. As the timing of clearing work is currently unknown, a Pre-Clearing Nesting Bird Survey and Field Assessment may be required to comply with the Federal Wildlife Act (such as if clearing occurs between late April and late August).

3.4.4. Quantitative Cost Risk Assessment

A Quantitative Cost Risk Assessment (QRA) of the pipeline routing alternatives was conducted. The focus of the QRA was to assess the Class 4 cost uncertainty to provide an understanding of the top cost risks and drivers and to determine a probabilistic contingency assessment. For pipeline Path A “with CNRL system upgrades”, there was a 66% confidence level associated with a 15% contingency. For Path B and Path C “without CNRL system upgrades”, the confidence level was 75%. The risk inputs and outputs for all projects were relatively similar.

Path A was ultimately deemed to be financially unviable due to the high capital cost required to complete the required pipeline and compression system upgrades. Path B and Path C were advanced for further evaluation.

3.5. Cost Estimating

Alternatives were screened initially at a Class 5 Cost estimate Level. Selected Alternatives were progressed to a Class 4 or Class 3 estimate for assessment, as applicable. Refer to Appendix D for cost estimate summary of the alternatives.

4.0 TRANSMISSION LINE CONSIDERATIONS

4.1. Background

The existing transmission pipeline was constructed in 1982. It comprises approximately 24.6 km of NPS4 (4" diameter) pipeline that runs between the TRGP and the Quintette lateral and 12.0 km of NPS3 (3" diameter) pipeline that runs from the Quintette lateral to the town of Tumbler Ridge for a total pipeline length of 36.6 km. The transmission pipeline is operated at high pressure (500 psig) and transports sales gas from the TRGP plant outlet to the town of Tumbler Ridge. The transmission pipeline also delivers gas to the CNRL Murray River meter station and to the Quintette meter station. Refer also to Figure 1.

- The CNRL meter station is located approximately 25.6 km from the TRGP. CNRL owns and operates the Murray River fuel gas distribution pipeline network that interconnects with the PNG(NE) transmission system.
- The Quintette meter station is located at the end of a 3.0 km segment of NPS2 pipeline (the Quintette lateral) that is owned and operated by PNG(NE). The interconnection of the NPS2 Quintette lateral with the NPS4 transmission system is located approximately 24.5 km from the TRGP.

To date, PNG(NE) has not experienced any issues with the integrity of the transmission pipeline. . The transmission pipeline was not designed for, and is not presently configured to perform, inline inspection work (i.e., it is not "piggable"). This limits the ability to use cleaning pigs, run inline inspection tools, and inject corrosion inhibitors. However, PNG(NE) has undertaken indirect inspections and plans to undertake integrity digs to ensure the ongoing integrity of the transmission line. As part of this alternatives analysis, PNG(NE) considered whether a further investment to make the transmission line piggable was appropriate.

PNG(NE)'s indirect inspection of the transmission pipeline was initially performed in 2020. The inspection utilized three inspection methods as follows:

- **ACVG** – Alternating Current Voltage Gradient: performed at 1-2 meter intervals across the entire pipeline to identify coating faults/damage
- **DCVG** – Direct Current Voltage Gradient: performed at coating defect locations to determine magnitude and direction of cathodic protection current
- **CIS** – Close Interval Survey: performed at coating defect locations to determine levels of cathodic protection

Indirect inspection of the pipeline was also performed in 2023 using Metal Magnetic Memory (MMM) technology to identify prospective areas of stress concentration, fatigue, and corrosion damage. MMM utilizes magnetic sensors to measure the magnetic field distribution above the pipeline and record changes (anomalies) in the magnetic field. Recorded anomalies may indicate corrosion, cracks, or other structural abnormalities such as dents.

These indirect inspections have not identified issues with respect to the ongoing integrity of the transmission pipeline.

4.2. Summary of Work Scope to Make the Pipeline "Piggable"

PNG(NE) retained Lauren Services to prepare an assessment of the work required (scope of work and Class 5 cost estimate) to make the transmission pipeline piggable in order to accommodate inline inspection. In general, the identified scope of work is to add shipping and receiving barrels, long radius elbows, risers, tees, and block valves. The Class 5 cost estimate for this work is $3.0 million.

Table 6 - Summary of Work Scope to Make the Pipeline "Piggable"

INDIRECT COSTS	$585,000.00
PNG Overhead	$325,000.00
Engineering	$180,000.00
Survey	$30,000.00
Archeological Assessment/Application	$30,000.00
Regulatory	$10,000.00
Environmental	$10,000.00
DIRECT COSTS	
Materials and Construction	$1,938,065.00
Construction Management & Inspection	$121,500.00
Total Base Cost Estimate	**$2,645,000.00**
Contingency at 15%	$396,750.00
Total Cost Estimate	**$3,042,000.00**

4.3. Conclusion

PNG(NE) Asset Integrity recommends that the NACE Pipeline External Corrosion Direct Assessment Methodology be applied to continue to manage the pipeline as an unpiggable line. PNG(NE) has since retained a third-party engineering firm to assess the indirect inspection data and develop a direct inspection (integrity dig) plan. The results of the indirect inspection assessment, coupled with future direct assessment data from integrity digs, will allow PNG(NE) to ascertain the current condition of the transmission pipeline and to manage future integrity requirements consistent with industry standards.

5.0 ALTERNATIVES EVALUATION METHODOLOGY

PNG(NE) applied a multi-criteria analysis involving a weighted-scoring methodology to evaluate the performance of each alternative using three categories of evaluation criteria: (1) Operations and Asset Management; (2) Project Delivery and Stakeholder Impact; and (3) Financial and Customer Impact. PNG(NE) internal subject matter experts validated the outcomes using expert judgement to determine the weighted score for each alternative. The components of the evaluation methodology are described in the discussion that follows.

5.1. Evaluation Criteria

The following evaluation criteria were applied in evaluating the identified alternatives.

1) Operations and Asset Management:
    a) Operational Reliability;
    b) Operations Requirements;
    c) Maintenance; and
    d) Environmental.
2) Project Delivery and Stakeholder Impact:
    a) Project Delivery;
    b) Environmental and Archaeology;
    c) Lands and right of way considerations;
    d) Consultation and engagement; and
    e) Socio-economic benefit.
3) Financial Impact:
    a) Capital cost; and
    b) Net present value (NPV).

5.1.1. Operations and Asset Management

PNG(NE) considered the following factors within the category of Operations and Asset Management:

- *Operations Reliability and Flexibility*: Ability of PNG(NE) to reliably achieve the system capacity required to meet existing demand, and the ability to provide flexibility for future growth and to address unplanned downtime;
- *Operations Requirements*: Degree to which the selected alternative considers factors such as resources, maintenance requirements, equipment and tools, operational hazards, etc.;
- *Maintenance*: Ability to maintain the equipment in a manner that ensures safe, reliable and cost-effective operations, and meets planned downtime needs; and
- *Environmental*: Degree to which environmental impacts are minimized once in operation (i.e. GHG emissions, NOx emissions, noise emissions, etc.).

5.1.2. Project Delivery and Stakeholder Impact

PNG(NE) considered the following factors within the category of Project Delivery and Stakeholder Impact:

- *Project Delivery*: Degree of difficulty relating to scope, permitting, cost, schedule, Environment, Health and Safety;
- *Environmental and Archaeology*: Degree to which environmental and archaeological impacts are minimized during execution of the project element (i.e. aquatic species and habitats, water quality and quantity, terrestrial species and habitats, species at risk, GHG emissions, First Nations interests);
- *Lands and Permitting*: Degree of difficulty associated with temporary and/or permanent land rights, as well as lifecycle impacts (i.e., landowners, new rights of way, project workspace);
- *Consultation and Engagement*: Degree of complexity with engaging Indigenous communities and other stakeholders (i.e., potentially impacted First Nations, general public and customers, British Columbia provincial government agencies, federal agencies, municipal and regional governments); and
- *Socio-economic Benefit*: Degree to which the project element creates positive impacts to the region through job creation and materials and services procurement during construction of the Project, as well as the use of hospitality and other local services; this also considers the public interest.

5.1.3. Financial and Customer Impact

The financial analysis of the alternatives is based on capital cost and net present value. In addition, PNG(NE) estimated the average 10-year increase in the cost of service as a proxy for rate increases. This approach generates an analysis that allows for an equitable comparison of each of the options.

Note – Refer to Appendix A for capital cost summary.

5.2. Methodology for Scoring and Weighting

PNG(NE) scored each project element alternative on an overall basis on a range from 0 to 5 based on their consistency with the definitions for each of the Evaluation Criteria as defined above. For the financial and customer impact criteria scoring, PNG(NE) scored the alternatives as shown in Table 7 below.

Table 7 - Criteria for Financial Scoring

Score	Description
0	No detailed cost estimate was prepared for the alternative if it is technically not feasible or it is screened out on a technical and cost basis.
1	The alternative is over 100% higher than the alternative with the lowest net present value (NPV) of incremental revenue requirement and the lowest capital cost.
2	The alternative is 50% to 100% higher than the alternative with the lowest NPV of incremental revenue requirement and the lowest capital cost.
3	The alternative is 20% to 50% higher than the alternative with the lowest NPV of incremental revenue requirement and the lowest capital cost.
4	The alternative is 5% to 20% higher than the alternative with the lowest NPV of incremental revenue requirement and the lowest capital cost.
5	The alternative with the lowest NPV (average over the entire analysis period) and those alternatives that are within 5% of the alternative with the lowest NPV and the lowest capital cost.

The financial evaluation scoring system compares the NPV of the incremental revenue requirement relative to the alternative with the lowest NPV of incremental revenue requirement. The financial analysis relies on the Association for the Advancement of Cost Engineering International (AACE International) Class 5 definition level estimates to ensure a fair comparison amongst the identified alternatives.[1] Tables 8 through 11 illustrate the weightings applied to the evaluation criteria for scoring the alternatives.

Table 8 - Weighting of Evaluation Criteria

Evaluation Criteria	Weight
Operations and Asset Management	30%
Project Delivery and Stakeholder Impact	30%
Financial and Capital Cost	40%

Table 9 - Weightings within Operations and Asset Management

Operations and Asset Management	Weight
Operations Reliability	50%
Operations Requirements	10%
Maintenance	15%
Environmental	25%

Table 10 - Weightings within Project Delivery and Stakeholder Impact

Project Execution and Stakeholder Impact	Weight
Project Delivery	25%
Environmental and Archeology	25%
Lands and Right of Way	20%
Consultation and Engagement	25%
Socio-economic Benefit	5%

[1] The capital cost figures presented in this section may differ than those presented in Section 5, since some cost estimates have been refined to AACE International Class 3 and Class 4 estimates.

Table 11 - Weightings within Financial and Capital Cost

Financial and Rates	Weight
NPV	50%
Capital Cost	50%

6.0 EVALUATION OF ALTERNATIVES

6.1. Scoring of Alternatives

The following discussion provides a summary of the evaluation of alternatives undertaken in accordance with the methodology described in Section 4. Further information on the scoring of each of the alternatives is provided in the sections that follow. The alternative scorings are supported by the financial evaluation summarized in Section 5.2.

6.1.1. Alternative 1 – Status Quo (Maintain Current Status – no Remediation)

The Status Quo alternative does not comply with stated project objectives. This alternative was not scored using the evaluation methodology.

6.1.2. Alternative 2 – TRGP Remediation

The TRGP Remediation alternative was scored using the evaluation methodology. The results of the analysis are shown in Table 12 below.

Table 12 - Alternative 2 Scoring

Alternative	Total Score	Operations and Asset Management					Project Execution and Stakeholder Impact						Financial and Rates		
		Sub-Total	Operational Reliability	Operational Requirements	Maintenance	Environmental	Sub-Total	Project Delivery	Environmental	Lands and Permitting	Consultation and Engagement	Socio-economic benefit	Sub-Total	Capital Cost	NPV
		30%	50%	10%	15%	25%	30%	25%	25%	20%	25%	5%	40%	50%	50%
Repair Plant	4.21	*3.00*	3	3	3	3	*4.35*	4	5	5	4	2	*5.00*	5	5

- Repair Plant had the highest score of 4.21. The Class 4 capital cost estimate was $3.6 million.

6.1.3. Alternative 3 - Virtual Pipeline (CNG or LNG)

Although the Virtual Pipeline (CNG or LNG) complies with the project objective of meeting long-term capacity and reliability requirements for residential and commercial customers, this alternative was not scored due to: (i) the emergent need to complete TRGP repairs in the short-term; (ii) the high capital and lifecycle costs; and (iii) the requirement for abandonment of gas service to existing large industrial customers.

6.1.4. Alternative 4 - New Sweet Gas Supply Pipeline

Alternative 4 was scored using the evaluation methodology for New Pipeline Path B and New Pipeline Path C only. New Pipeline Path A was not scored due to high capital costs. New Pipeline

Path B had a score of 2.98, with an estimated capital cost of $36.3 million. New Pipeline Path C had a score of 2.70, with an estimated capital cost of $33.5 million. The results of the analysis are shown in Table 13 below.

Table 13 - Alternative 4 Scoring

Alternative	Total Score	Operations and Asset Management					Project Execution and Stakeholder Impact						Financial and Rates		
		Sub-Total	Operational Reliability	Operational Requirements	Maintenance	Environmental	Sub-Total	Project Delivery	Environmental	Lands and Permitting	Consultation and Engagement	Socio-economic benefit	Sub-Total	Capital Cost	NPV
		30%	50%	10%	15%	25%	30%	25%	25%	20%	25%	5%	40%	50%	50%
New Pipline Path A - Blue (w/ CNRL)	0.00	-					-						-		
New Pipline Path B - Purple (no CNRL) (includes repair plant until 2028)	2.98	*4.00*	4	4	4	4	*2.60*	3	3	2	2	4	*2.50*	1	4
New Pipline Path C - Green (no CNRL) (includes repair plant until 2028)	2.70	*4.00*	4	4	4	4	*1.65*	2	2	1	1	4	*2.50*	1	4

6.2. Financial Evaluation

Table 14 summarizes the results of the financial evaluation and illustrative 10-year rate impact analysis based on Class 4/Class 5 level cost estimates, as applicable, for each alternative.

Table 14 - Financial Evaluation of Alternatives Summary

	Alternative	Description	NPV[1]	Rate Impact (10 year average)
1	Status Quo[2]	Operate the Tumbler Ridge Gas Plant and transmission pipeline in its current state.	n.a.	n.a.
2	Tumbler Ridge Gas Plant Remediation	Addressing several critical integrity concerns related to the safety and operability of the overall plant.	$26.9MM	44%
3	Virtual Pipeline (CNG) and Decommission Plant	Establish a new gas supply via CNG. Decommission the TRGP and a portion of the associated transmission pipeline.	$59.5MM	195%
	Virtual Pipeline (LNG) and Decommission Plant	Establish a new gas supply via CNG. Decommission the TRGP and a portion of the associated transmission pipeline.	$33.4MM	98%
4	New Sweet Gas Pipeline and Decommission Plant	Establish a new gas supply via a new pipeline (3 routing options) to connect CNRL Bullmoose system to the CNRL Murray River System and decommission the TRGP and a portion of the associated transmission pipeline.	$43.9MM - $51.4MM	134% - 150%

6.3. Summary of Evaluation

Table 15 below provides a summary of weighted scores for the assessed alternatives. Based on the methodology, Alternative 2 – *Repair Plant* – is the highest scoring alternative.

Table 15 - Scoring Summary for Alternatives

Weighted Score	Alternative	Alternative Description
4.21	2	TRGP Remediation (Recommended)
2.98	4	New Gas Supply and Decommission Plant – Path B
2.70	4	New Gas Supply and Decommission Plant – Path C
Not Scored	1	Status Quo (Maintain Current Status – No Remediation)
Not Scored	3	Virtual Pipeline (CNG or LNG) and Decommission Plant
Not Scored	4	New Gas Supply and Decommission Plant – Path A

7.0 APPENDIX A – CLASS 4 ESTIMATE SUMMARY

LAUREN

TR Gas Supply Diversification - Class 4 Cost Estimate - Summary

		Alternative						Alternative					
Scenario		1	2	3	4	5	7	1	2	3	4	5	7
Scope	Sub-Project Total	New Pipline Path A (w/ CNRL)	New Pipline Path B (no CNRL)	New Pipline Path C (no CNRL)	LNG Only (Purchase)	CNG (Purchase)	Repair Plant	New Pipline Path A (w/ CNRL)	New Pipline Path B (no CNRL)	New Pipline Path C (no CNRL)	LNG Only (Purchase)	CNG (Purchase)	Repair Plant
NPV													
NPV (Low)													
NPV (High)													
NPV (Median)													
Pipeline Maintenance - Full Existing							X						X
Pipeline Maintenance - Remaining Existing		X	X	X	X	X		X	X	X	X	X	
Plant Maintenance after 2027							X						X
O&M Costs to 2027		X	X	X	X	X	X	X	X	X			X
Capital Cost													
Pipeline													
New Pipeline - Path A	$21,434,065	$21.4						X					
New Pipeline - Path B	$31,099,835		$31.1						X				
New Pipeline - Path C	$28,284,319			$28.3						X			
New Sales Meter to CNRL - Class 5	$1,850,400	$1.9						X					
Adandon Existing Transmission Line	$2,559,000	$2.6	$2.6	$2.6	$2.6	$2.6		X	X	X	X	X	
Pipeline Integrity - Full Existing	$600,000						$0.6						X
Pipeline Integrity - Remaining Existing	$600,000	$0.6	$0.6	$0.6	$0.6	$0.6		X	X	X	X	X	
Make Piggable Full Existing	$3,042,000												
Make Piggable Remain. Existing	$602,000												
Virtual Pipeline													
LNG (Class 5 Campus Cost)	$7,460,000				$7.5						X		
CNG (Class 5 Change Energy Cost)	$8,765,979					$8.8						X	
Plant													
Plant Upgrades	$3,000,000						$3.0						X
Plant Decommissioning	$2,065,541	$2.1	$2.1	$2.1				X	X	X	X	X	
CNRL													
System Upgrades (PL / Compression) - Class 5	$15,216,000	$15.2						X					
Upstream Gas Supply Upgrades	$831,200												
Total		$43.73	$36.32	$33.51	$10.62	$11.92	$3.60	$43.7	$36.3	$33.5	$10.6	$11.9	$3.6

8.0 APPENDIX B – DESCRIPTION OF SCOPING DOCUMENTS / ENGINEERING ASSESSMENTS

With the assistance of subject matter experts and various third-party firms, PNG(NE) completed a variety of screening level studies and estimates to inform the evaluation of alternatives. The process and methodology is summarized in Section 1.3 and summarized below:

<u>Phase 1 - Screening</u>

From 2021 – 2023, PNG identified and assessed alternatives for long term gas supply at a screening (typically Class 5 Estimate) level to determine viability and feasible options for further considerations. These assessments included

- Studies and proposals for permanent LNG or CNG supply
- Class 5 scoping and estimating of potential new gas supply pipeline routing, pipeline decommissioning, and plant decommissioning
- Historical assessments of the TRGP and transmission line and Class 5 Estimates for repairs
- Review of industrial equipment process safety standards, hazard and operability analysis, and standards of sour gas plant operations.

<u>Phase 2 - Alternatives Assessment</u>

Following the screening process, studies for the two primary alternatives to be in line with AACE Class 4 Estimating were conducted, including the following:

- Repair Plant
  - Engineering studies of damaged equipment (Amine Contactor, reflux piping, etc.)
  - Detailed scoping of project components based and reviews of the performance and condition of the Tumbler Ridge Gas Plant (TRGP) from HAZOP reports, NDE Inspection reports of Vessels and Piping,
  - Acquisition of budget and firm pricing quotes and proposals for various services and materials required for 2024 and 2025.
- New Sweet Gas Pipeline
  - Engineering study for suitable pipeline sizes and design requirements such as wall thickness, grade, etc.
  - Routing study inclusive of Lands, Archaeological, Environmental, and Survey desktop studies to identify and select preferred routing alternatives.
  - Class 4 estimating and Monte Carlo assessment
- Plant and Pipeline Decommissioning
  - Desktop studies as well as site investigations and Class 3 cost estimating for plant decommissioning
  - Class 5 Cost estimating for pipeline abandonment for the portion of the existing transmission pipeline to be decommissioned

Appendix C – Basis of Estimate

BASIS OF ESTIMATE

Tumbler Ridge Gas Plant Rehabilitation Project

Pacific Northern Gas (NE) Ltd.

Doc No: PNG002-003-0232-RPT-0001

0	2024-08-11	Issued for Use	Scott Arnold, LS	C. Paradis, S2F	G. Pavlik, LS
Rev	**Date**	**Description**	**By**	**Checked**	**Approved**

Table of Contents

1.0 INTRODUCTION

1.1 Background

Pacific Northern Gas (NE) Ltd., the Company, owns and operates the Tumbler Ridge Gas Plant (TRGP). The TRGP receives raw untreated natural gas supplied by CNRL from its Tumbler Ridge North Grizzly field operations. The TRGP equipment processes and treats the raw natural gas remove harmful hydrogen sulfide (H_2S), carbon oxides (CO_x), Sulphur oxides (SO_x), and excess water from the raw gas. The processes at TRGP enable safe public distributable quality gas supply to PNG customers in the Tumbler Ridge area via the PNG Tumbler Ridge transmission pipeline. Without TRGP, the raw gas cannot be safely used by the public.

It is important to note that the TRGP is the only public spec gas supply connected to and serving the Tumbler Ridge area. Thus, this is a strategic asset for PNG and from a public perspective it should be considered a *Critical Infrastructure* for the region.

The TRGP was built and commissioned in 1983-84. The facility remains essentially unchanged from the original design capacity and function. Over the 40 years of operation, there have been changes to the incoming raw gas to be treated as well as changes in the volume demands of the end users of the cleaned gas. Also, much of the original equipment remains in service. Though basic maintenance is periodically performed to continue operation of the gas plant, over time the operating conditions of the TRGP facility have changed and the costs to maintain the aged equipment has increased.

From 2021 through 2023 PNG conducted reviews of the capacity, performance, condition, and compliance of the TRGP to current programs. These reviews engaged the support of various subject matter experts in matters of forecasting of available raw gas supplies, forecasting of customer service requirements, industrial equipment process safety, personnel hazards and equipment operability reviews, systems integrity inspection intervals, current standards of sour gas plant operations, gas plant process simulations, and technical - engineering evaluations of specific concerns.

These reviews were focused on:

1. Assessing the current and future needs of the Tumbler Ridge community and surrounding area directly dependent on the TRGP and its distribution infrastructure. These include residential, industrial, and commercial users
2. Assessing the current condition and solutions to aged or damaged equipment that affect the gas processing capacity and reliability of service.
3. Identifying original equipment deficiencies and solutions that by current standards pose operability or process safety concerns to the people or the environment at the site.
4. Assessing the current status and solutions for compliance of TRGP activities to the PNG asset integrity program and current regulatory environment.

The findings of the reviews indicate that the TRGP requires repairs, replacements, and upgrades to meet the needs of PNG and the Tumbler Ridge region that depends on it. The solution for TRGP is in the form of an overall scope of work compiled from the recommendations developed for the facility by the reviews and technical studies. The scope of work is a list of jobs and projects that consists of multiple works across five categories.

1. Replacement of equipment that is no longer serviceable.
2. Repairs or alterations to serviceable but deteriorated or deficient equipment

3. Installation of new equipment
4. Improvements to operating practices and tools
5. Improvements to maintenance practices and tools.

PNG intends to complete the work by risk priority through a combination of what can be done while the gas plant is in operation and those works that require the plant to be shut down and completely de-energized in order for the work to be able to be done safely.

The project will be executed in two phases. Phase 1, in 2024, will address urgent program compliance concerns and basic equipment repairs required for reliable operations through the 2024/2025 heating season (winter). Phase 2, in 2025, will complete the bulk of the repairs, replacements, and upgrades needed to establish forecasted processing capacity requirements and the base equipment conditions needed for the TRGP to continue provide safe and reliable operation to the community and area of Tumbler Ridge, to PNG, and PNG stakeholders.

1.2 Purpose

The purpose of this report is to provide an understanding of the methodology and the basis of the estimate presented for the 2024 and 2025 plans for the facility. The information includes clarity of scope considered in the estimate, and references to the quotations and estimate buildups used to determine the total installed cost of the repairs.

1.3 Purpose of Estimate

The estimate will be used by Company to support a Section 44.2 expenditure application to the BCUC. The application is planned for Q3 2024.

1.4 Location

The project is located at the TRGP approximately 40 km outside of Tumbler Ridge. Figure 1 provides an overview of the gas plant location and the transmission system the transports gas processed by the gas plant to PNG (NE) customers. The gas plant is accessible via HWY 52.

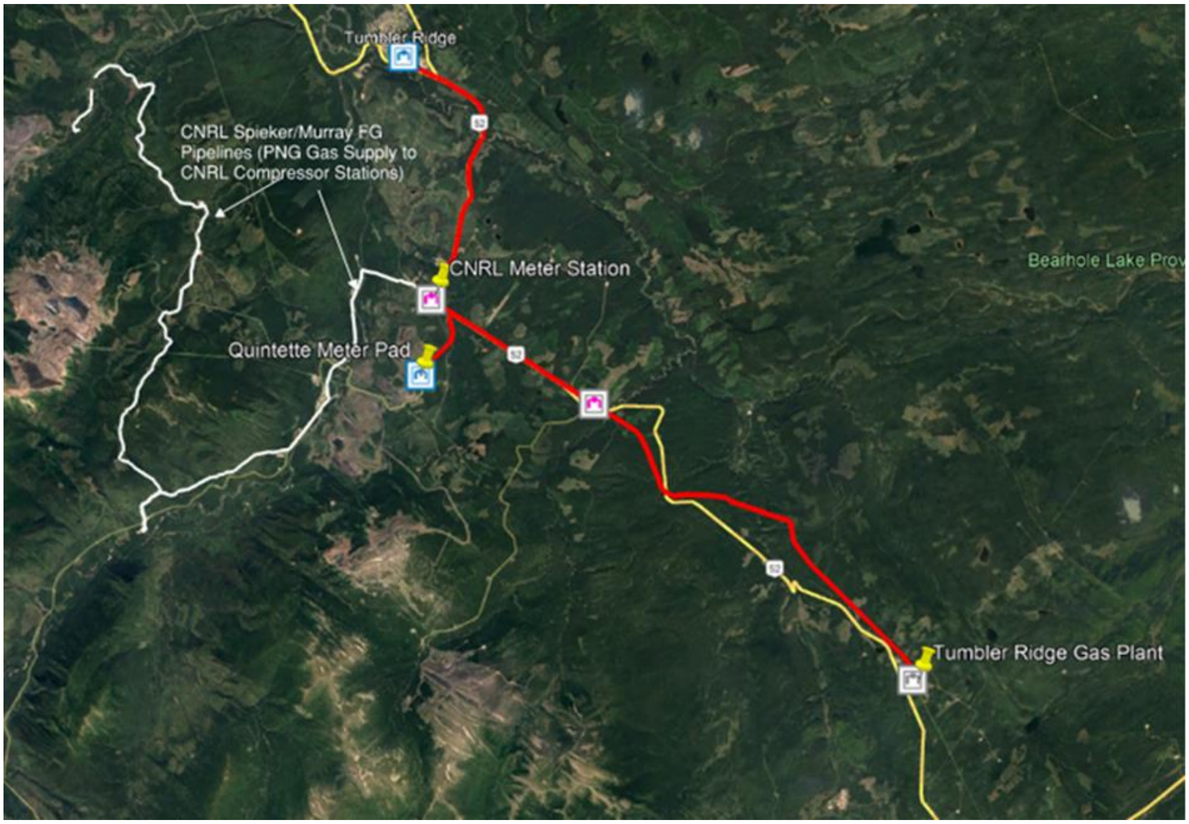

Figure 1 – Tumbler Ridge Gas Plant and Transmission System

1.5 References

- This report summarizes the work from various studies and reports through the course of the project development. Refer to Appendix B and C for summaries of supporting documentation.

1.6 Definitions

- Contractor — Construction contractor engaged in any work covered by this document and TRGP Scope Worksheet.
- CSA Z662 – CSA Z662-23 Oil and Gas Pipeline Systems, National Standard
- BC OGPFR – BC Oil and Gas Processing Facility Regulation
- Engineer – The engineering consultant
- Company – The project owner, Pacific Northern Gas (N.E.) Ltd.
- Specifications – Codes and Standards, Regulations, material or equipment specification

1.7 Acronyms

- AACE – American Association of Cost Engineers
- TSBC – Technical Safety BC Regulator
- COHSR – Canada Occupational Health and Safety Regulations
- BCER – British Columbia Energy Regulator
- NDE – Non-destructive Examination
- PNG – Pacific Northern Gas
- ROW – Right of Way
- TWS – Temporary Workspace
- QEP – Qualified Environmental Professional
- WBS – Work Breakdown Schedule

1.8 Estimate Scope Basis

The cost estimate includes activities outlined in Appendix A – 2024-2026 Work Scope List and Estimates, which includes:

Phase 1 - 2024 scope:

Deteriorated Asset Repair:

- Addressing the amine regeneration reflux circuit that inhibits the process from reaching acceptable operating parameters. This has resulted in corrosive equipment damage and numerous plant upsets due to lack of reflux flow. This involves replacing the piping with increased diameter size piping and repair/replacement of the reflux pumps.
- Replacement of missing/malfunctioning gauges not accessible during normal operation.
- Wall thickness assessment of piping in areas of concern to finalizing piping replacement scope for 2025.

Critical Safety Improvements:

- As-Built drawings and documentation to allow for safe operation of the plant and the technical references needed for engineering of 2024/2025 scope items.

Integrity Management Plan Requirements:

- Enhanced external NDE inspection surveys of areas of concern on vessels to identify potential repair needs of these equipment as either requiring immediate attention or in 2025. This will allow for the plant to be safely operated to 2025 when internal inspections will be performed.

Hazop Close-out:

- Replacement of a pressure safety valve with a new valve rated for sour service.
- Test and repair the vacuum breaker on the liquid drains tank to ensure safe operation of tank during pump-out.

Plant Outage Activities:

- Blinding, depressurizing, purging of the plant equipment and piping.

- Operations management and Construction management of plant outage.
- Safety, Medic, and Air trailer support required for the outage.
- Site services: trailers, wash cars, hydrovac, and disposal.
- Commissioning support.
- De-blinding, and plant start-up support.

Engineering:

- Engineering for the reflux piping and pump scope of work.

Project Management:

- Project management, supply chain management and cost reporting for the 2024 work scope.

Outage Planning:

- Detailed work planning for 2024 work including: coordinating and management of contractors for work tasks, schedule development, and estimate development.

Phase 2 - 2025 scope:

End of Life Asset Replacement:

- Replacement of the amine absorber vessel and trays.

Deteriorated Asset Repair:

- Repair of amine circulation pumps.
- Repair/Replacement of amine charge pumps.
- Replacement/Repair of control valves.
- Upgrade of the plant PLC control panel terminal strips.
- Replacement of amine plate exchanger plate pack.
- Replacement of flare tip.
- Replacement of corroded piping.

Operational Compliance Upgrades:

- Maintenance of flare stack blackened area.
- Flare fuel gas meter.
- Installation of pipeline isolation and blinding location.
- Procure and install inlet H2S gas analyzer.
- Procure and install dew point analyzer on outlet of plant.
- Procure and install PSV on mercaptan tank.
- PLC Programming to prevent re-occurrence of high differential pressure surges.
- Procure and install sales gas filter.

Critical Safety Improvements:

- Review of 1983/84 plant piping specifications, update to current standard, and issue for 2025 engineering work and plant maintenance in future years.
- Install correct H2S alarm beacon lenses.
- Inspection of the flare-stack guy wires integrity.
- Address emergency generator deficiencies: fuel filter and ESD installation.
- Piping improvements for process safety: Dehy cold start-up bypass, mercaptan tank site glass blowdown piping, blanket gas for make-up water tank, and flow control to the charcoal filter.

Integrity Management Plan Requirements:

- Inspections of vessels and tanks.
- Remove and cap 2” raw gas start-up piping.

Hazop Close-out:

- Confirmation of numerous shutdowns via a shutdown key verification.
- Correcting deficiencies on vent and drain piping for F-104 (glycol filter).
- Installation of purge gas on F-101 and F-101 (amine filters).
- Install upgraded trunk cable to control panel to allow for control system upgrades during outage.
- Procure and install ESD actuator for amine absorber low level valve.
- Hardwire ESDs buttons to SD relays.
- Re-route sweep gas for TEG reboiler to a non-odorized location.
- Procure and install H2S detection for the aerial cooler.

Plant Outage Activities:

- Blinding, depressurizing, purging of the plant equipment and piping.
- Construction management of plant outage.
- Safety, Medic, and Air trailer support required for the outage.
- Site services: trailers, wash cars, hydrovac, and disposal.
- Commissioning support.
- De-blinding, and plant start-up support.

Engineering:

- Engineering for the following scopes:
    - Amine absorber replacement
    - H2S and Dew Point analyzer installations
    - Mercaptan Tank PSVH
    - Dehy Cold Start-up By-Pass

  - Remove and cap 2" raw gas start-up line
  - F-100/F-101 Modifications – N2 Blankets, globe valve installation, and PSV piping reconfiguration
  - Re-route H-101 sweep gas to non-odorized source
  - Make-up water tank blanket gas
  - Piping replacements
  - Flare fuel gas (lift gas) meter replacement
  - Control panel updates
  - H2S and Dewpoint Analyzer installations
  - H2S detector for aerial cooler

Project Management:

- Project management, supply chain management and cost reporting for the 2025 work scope.

Outage Planning:

- Detailed work planning for 2025 work including: coordinating and management of contractors for work tasks, schedule development, and estimate development.

The estimate includes the materials, contract labor, equipment, site services, engineering, project management, HSE resources, regulatory/land support, and construction management to execute the scope identified above.

Table 1 - Cost Basis Summary Table

Cost Basis	2024 CAD Dollars
Escalation	0% (see Section 6.0 for exceptions)
Contingency	44% (2024) and 46% (2025) of Sub-Total (P90)
Taxes	Excluded
Owner's Costs	Excluded
Pre-Commissioning	Included
Commissioning & Start-Up Labour	Included
Construction Schedule	See Section 0
Construction Execution	PNG as prime, S2F as construction and commissioning manager
Construction Inspection	Included
Construction Management	Included

1.9 AACE Classification

1.9.1 Scope Definition

The level of project definition at this time is approximately 10-40%, based on the following:

- Project Scope Description – defined
- Work Breakdown Structure – 2024 defined, 2025 prelim
- Project Schedule – 2024 defined, 2025 prelim
- Risk Register – defined
- Execution plans – 2024 defined, 2025 prelim

- Contracting Strategy – 2024 defined, 2025 prelim
- Integrated Project Plan – prelim TA PEP
- Project location - defined
- Permitting – not started – process understood from past projects – only flare blackening scope requires permitting
- Geotech – not started – not required
- Engineering design – in progress 2024, prelim 2025
- Pipe specifications – defined for 2024, in progress for 2025
- Long lead materials – defined

The cost estimate was comprised of a mix of Class 2 to Class 5 estimate items based on the level of scope definition and information available at this time. The Association for the Advancement of Cost Engineering International (AACE) range of estimate accuracy and the resulting cost estimate classification is well-documented and is based on the assessment of thousands of completed projects. AACE recommends that whenever possible a quantitative risk assessment be conducted on the project in question to assess the specific range of accuracy and resulting cost estimate classification. A quantitative risk assessment was conducted on this project and the overall result for 2024-25 indicates an expected range of accuracy of -17% to +23% which can be classified as a Class 3 estimate (see AACE Recommended Practices 104R-19 and 18R-97).

To improve the class of estimate, the following deliverables are recommended to be developed further:

- Design – defined, including the following:
  - Sizing and general arrangement placement of the sales gas filter
  - Confirmation of charge pump repair/replacement scope
  - Design of blanket gas for make-up water, F-100, and F-101
  - Design of the gas plant battery blinding locations for pipeline isolation and blinding
- Detailed material and services estimates and quotations from contractors who will be executing 2025 scopes of work
- Long lead materials – defined, firm quotes received for remaining 2025 procurement items that do not have quotes.
- 2024 inspection scope to confirm piping replacement scope for 2025 and any vessel repair work.

1.10 Estimate Confidence Level

The estimate confidence level selected by the Company is P90 (90% confidence level that the cost estimate will not be exceeded). See the P90 Net Cost Risk % as determined by the Quantitative Risk Analysis (Cost QRA, Monte Carlo), dated July 31st, 2024.

2.0 METHODOLOGY

An estimate for each job/project in the overall scope of work for TRGP was prepared.

The method used to develop the overall estimate for TRGP is described as: job by job bottom up effort driven. The cost accuracy and contingency for each line item is derived from the information available at the date of issue using the estimating tools per the following tables 2 and 3. The estimates stem from a combination of quotes from vendors and contractors, referencing comparative projects, and discussion exercises on each job by experienced gas plant maintenance coordinators. As the planning for each item progresses to reduced estimate class (CLx) criteria, the cost accuracy improves and is updated.

Table 2 – Basis of Estimate Summary

BASIS OF ESTIMATE		Estimate Contingency
CL5	Feasibility phase. Concept Description. Indicative. Order of magnitude. Based on like/similar projects in scope and scale.	75%
CL4	Prelim Design phase. Scope understood. Recent relative - comparative project may be available. Gaps filled by assumptions and experienced judgement. Major equipment known. Major activities and effort level by man-day.	50%
CL3	Detail Design phase. Scope understood. Docs Available are – IFI, area GA drawings, PID markups, standards, specifications, major equipment ga, major materials list qtys, specific niche skills identified, major activities and effort level by man-day per skill. Recent relative - comparative RFP/RFQ may be available.	30%
CL2	Tender / Bid phase. Engineered packages and construction drawings complete, IFC. Equipment datasheets complete. Bills of materials complete. Effort level resourced to WBS by man-hour per skillset. RFQ/RFP issued and received.	20%
CL1	Implementation / Execution phase. Detailed WBS to level appropriate to the job. Progress tracking, variation and change order control, cost controls.	15%

Table 3 – Units Rates for Estimate

RATES for CL5/CL4 estimates (until CL3/CL2 level information is reached)		
Mob/ Demob personnel	per person per occurrence	750
LOA, TRGP site work only	per person per day. Accommodation, meal, local commute	300
Rate, ALL personnel all locations	Flat hourly rate per person. Includes overhead	150
Mob/ Demob SP equipment	Per unit per occurrence	2500
Rate, SP equipment, Rigging, BoomPick, ManBasket	Flat hourly rate per unit. Includes overhead	350
Truck; Vac and Waste	Flat hourly rate per unit. Includes overhead, hauls excluded	350
Crane, trays/vessel	Flat hourly rate. Includes overhead	1200
Misc Rental Equipment.	Flat daily rate per unit. Includes overhead	250

3.0 DESIGN BASIS

Repairs and replacements identified are being completed to ensure the plant can reliably and safely deliver gas to the PNG(NE)'s customers per the revised designed basis for the plant. All repairs and replacements will be completed in accordance with the applicable codes and regulatory requirements.

4.0 ESTIMATES

Table 4 below provides a summary of the estimated cost fort2024 and 2025.\

Table 4 – 2024 Total Cost Estimate Summary

Description	Cost
Owner's PMO and Indirects	excluded
Engineering	$30,000
Planning	$86,000
Project Management	$90,000
Deteriorated Asset Repair	$128,000
Critical Safety Improvements	$18,000
Integrity Management Plan Requirements	$50,000
Hazop Closeout	$39,000
Plant Outage Activities	$249,000
PST	$1,000
Sub-Total	$691,000
Contingency (44%)	$317,000
Total	**$1.008,000**

Table 5 – 2025 Total Cost Estimate Summary

Description	Cost
Owner's PMO and Indirects	excluded
Engineering	$290,000
Planning	$147,000
Project Management	$140,000
End of Life Asset Replacement	$451,000
Deteriorated Asset Repair	$197,000
Operation Compliance Upgrades	$467,000
Critical Safety Improvements	$63,000
Integrity Management Plan Requirements	$156,000
Hazop Closeout	$110,000
Plant Outage Activities	$662,000
PST	$46,000
Sub-Total	$2,729,000
Contingency (46%)	$1,181,000
Total	**$3,909,000**

4.1 Opportunities

The following opportunities exist to realize cost savings:

- Use Company hydrovac
- Use Company underground line locating technicians
- Use Company spare parts, spared equipment, and suitably assessed excess materials from other facilities and projects
- 2024 inspection piping inspection may reduce scope for piping replacement.

5.0 SCHEDULE

The following schedule constraints have been assumed:

Table 6 – Schedule Constraints

Constraint	Date
2024 Outage	September 4th – 14th
44.2 Approval	February 2025
2025 TRGP Plant Outage	September 2025

6.0 ESCALATION

Excluded. Escalation will be applied by Company to future years based on the finalized project schedule.

7.0 PROJECT EXECUTION STRATEGY

Preliminary planning items detailed below.

7.1 Planning and Contracting Basis

The Company will contract the PMO which will include project management, project engineering, project controls, supply chain management, lands, regulatory, contract administration, construction management and quality. Company Operations will support work permitting, blowdowns, tie-ins, and commissioning.

The Company will contract directly for the following:

- Engineering
- Project Management
- Contract Administration and Procurement Support
- Project Controls
- Land/Survey/Regulatory for Flare Blackenning
- Construction
- Construction Management
- Commissioning
- Safety, Medics, Safety Watches and Air Trailers
- Site Services: Hydovac, Trailers, Rentals, Wash car, disposal.
- Inspection

7.2 Regulatory / Permitting Strategy

Construction activities are regulated through the BC Energy Regulator. The required permits expected for the project include:

- Facility amendment for extending lease boundary for Flare Blackening scope in 2025.

7.3 Procurement Strategy

All equipment will be procured by the Company. Contractors will supply piping and electrical materials, and consumables.

7.4 Start Up & Commissioning Plan

Startup & Commissioning Plans for the facility have been developed by S2F and are included in the TA planning and execution estimates.

8.0 DOCUMENTATION

The detailed development of the estimate for each work scope is presented in Appendix A

In compiling the estimate, information provided by others has been relied on and has been assumed to be accurate and reliable for the purposes of the estimate. Refer to the TRGP Capital and OM Estimate Summary - 2024 TRGP TA

- TRGP Capital and OM Estimate Summary - 2025 TRGP TA

Appendix B – Documentation Supporting 2024 Estimates and Appendix C – Documentation Supporting 2025 Estimates for a summary of third-party estimates received.

Table 7 – 2024 Supporting Documentation

Vendor	Scope	Notes
01 - Deteriorated Asset Repair		
Sureline	Reflux Piping Estimate	
Iris	Piping wall thickness assessment Estimate	
Service Onsite	Reflux Pump Service Quote	
Service Onsite	Reflux Pump Replacement Quote	
02 - Critical Safety Improvements		
WSP	EICA Asbuilt Proposal R1	
WSP	WSP Asbuilts CO-001	
03 – Integrity Management Plan Requirements		
IRIS	Pre-TA Vessel Inspection Estimate	
Chinook	TRGP Scaffold Quote	
Trans Peace	TRGP UT Inspection Insulation Removal	
04-Hazop Closeout		
Kings Energy	PSV 2020-1 Replacement Quote	
05- - Plant Outage Activities		
S2F	2024 Execution Estimate	
Trojan Safety	2024 Medic and Air Trailer	
HALO	Hazardous Materials Sampling	
Copper Tip	N2 Purge Gas Estimate	
06 – Planning, PM, and Engineering		
S2F	2024 Planning Estimate	
Lauren Services	2024 TRGP TA – Reflux Piping Mods	

Table 8 – 2025 Supporting Documentation

Vendor	Scope	Notes
01 – End of Life Asset Replacement		
Foremost	Amine Absorber Quote	
Koch	Tray Replacement Quote	
02-Deteriorated Asset Repair		
Service Onsite	Amine Charge Pump Quote	
WCE	Amine Exchanger Plate Replacement Quote	
03 – Operation Compliance Upgrades		
N/A		
04 - Critical Safety Improvements		
N/A		
05 – Integrity Management Plan Requirements		
Warco	Bundle Pulling Estimate	
06-Hazop Closeout		
N/A		
07- - Plant Outage Activities		
S2F	2025 Execution Estimate	
Avenge	Chemical Cleaning Estimate	
08 – Planning, PM, and Engineering		
S2F	2025 Planning Estimate	
Lauren Services	2025 Engineering Estimate ROM	
Lauren Services	2025 PM – ECN-002	

9.0 FREIGHT & TAXES

Freight has been included in the equipment pricing. Provision has been made in the cost estimate for BC PST.

10.0 CONSTRUCTION LABOUR ESTIMATE BASIS

10.1 Contractor Field and Equipment Rates

Equipment and labour rates as detailed below. These are baseline values and assumptions used to develop the estimates presented in Appendix A.

Table 9 – Construction Labour Rate Basis Summary

Construction General	Unit Rate	UOM	Notes
Mob/Demob Person	$750	per person per occurrence	
LOA	$300	per person per day	Accommodation, meal, local commute for TRGP only
Rate, All Personnel	$150.00	per hour	Flat hourly rate, includes overhead
Mob/Demob Specialty Equipment	$2,500.00	Per person per occurrence	
Rate, Specialty Equipment – Boom truck, AWP, etc	$350.00	per hour	Includes overhead
Truck, Vac and Waste	$350.00	per hour	
Misc equip rental – compressor, hydro pump etc	$250.00	per day	Includes overhead
Crane, trays/vessels	$1200	Per hour	Flat hourly rate, includes overhead

10.2 Construction Indirect Costs

Construction indirects are based on schedule duration and base hourly rates, except where noted below. These are included in “Plant Outage Costs” and are as follows:

- Indirect personnel, including Project Supervision, Administration, HSE and QC, Medic
- Site Services: wash car, trailers, hydrovac, disposal.
- Chemical cleaning contractor for train wash – contractor estimate used a basis from Avenge.
- Chemical refills or top-ups for amine, heat medium (EG), and dehydration glycol (TEG) – volume assumptions were made and base per litre pricing from Brentagg was used:
    - Amine (Puratreat) - $7.83 per liter
    - Heat Medium (DownTherm) - $2.50 per liter
    - TEG - $7.25 per liter
- Hazardous waste disposal – Secure Energy standard rates
- Subsistence.

10.3 Construction Management & Inspection Basis

Site execution operations and construction management is provided by S2F and has been included in the execution estimates for 2024 and 2025. Construction management is included in "Plant Outage Costs" for 2024 and 2025.

Construction inspection is included in each of the line items in the TA estimate prepared by S2F as a speciality service and assumed as by the site lead of the contractor executing the work.

10.4 Commissioning

Commissioning will be performed by S2F and is included in the execution estimates. This is included in "Plant Outage Costs".

11.0 COMMERCIAL IMPACT & OUTAGE

The 2024 work will coincide with the CNRL 2024 outage. The customers in town will be supplied with gas via LNG. Quintette and the industrial park via line pack. There will be no interruption of service for customers.

The outage plan for 2025 is still to be finalized. It is anticipated that the outage will occur during the summer and there is an opportunity to work with CNRL to bypass the plant with sweet gas during the outage to minimize LNG/CNG costs during the outage.

12.0 OWNER COSTS

Company PMO and Owner Indirect costs have been excluded and will be added by the Company.

13.0 INDIRECTS & OTHERS

13.1 Engineering and Procurement Support

The 2024 engineering estimate was based on an estimate provided by Lauren services for the scope of work.

For 2025 it was included as 15% of direct costs. This was verified by a budgetary estimate prepared by Lauren services for the scopes of work requiring engineering.

13.2 Survey/Permitting/Lands

Survey permitting and land work will be required for the Flare Blackening scope in 2025. An estimate for this work from Roy Northern was provided to PNG and has been used for developing the estimate for this scope, $40,000. Vector provided an estimate for the survey support required for the work, $6,000.

13.3 Turn Around Planning

Turnaround Planning costs for the 2024 and 2025 work scopes are as per S2F Estimates in Appendix B for 2024 and Appendix C for 2025.

13.4 Contingency

For 2024 the P90 contingency is 46% contingency and for 2025 the P90 contingency is 44%. This aligns with the P90 net cost risk % of the Cost QRA / Monte Carlo report, dated July 31, 2024, and included as Appendix D for reference.

P90 was selected primarily to reflect the high level of uncertainty associated with the found work due to the vessel and piping inspections. Also, the 2025 estimates were based on a built-up level of effort estimate prepared by S2F and detailed contractors and equipment were not used.

Contingency has been included to account for:

- errors and omissions in the estimating process
- risk events / unforeseen items that are expected to occur that are not known (i.e., weather delays)
- small changes in scope

Contingency excludes:

- significant changes in scope
- major unexpected work stoppages (i.e., strikes)
- natural disasters
- management reserve
- escalation and currency effects

13.5 Risk

The cost impacts of post-mitigation risk events are covered by contingency. It is assumed that only a portion of risk events will be realized when mitigations are applied appropriately based on past projects.

Costs of mitigations that are unique to the project and are not inherent to other work activities have been included as a separate cost.

These risks are summarized in the QRA risk assessment dated July 31st, 2024.

13.6 Management Reserves

Excluded.

14.0 ASSUMPTIONS, EXCLUSIONS & CLARIFICATIONS

1. Costs are in 2024 CAD. Escalation is excluded.
2. 2024 and 2025 TA construction schedule will be 7 days a week – day shift only with the exception of NDE, chemical train wash and any post weld heat treatment required.
3. Suitable laydown yard for pipe and material storage to be available in convenient proximity to the project.
4. No camps assumed. Out of town personnel will stay in hotel in Tumbler Ridge.

APPENDIX A – WORK BREAKDOWN STRUCTURE

- TRGP Capital and OM Estimate Summary - 2024 TRGP TA
- TRGP Capital and OM Estimate Summary - 2025 TRGP TA

TRGP Capital and O&M Estimate Summary - 2024 TRGP TA Compliance Items only, No Amine Contactor

Capital

		2024	2025	Total
A Scopes - End of Life Asset Replacement				
	Replace Instrument Air Compressor Package - Scope Moved to Separate AFE			-
		-	-	-
B Scopes - Deteriorated Asset Repair				
	Above Ground Corroded Piping (9 locations) - inspect only 2024	23,200		23,000
	Replace Amine Reflux Discharge Piping and Pump	91,270		91,000
	Replace Faulty and Missing Instrumentation	10,000		10,000
	Other (2) - Replace LG-403, PB Valve on Sight Glass Reflux Accum.	3,300		3,000
		127,770	**-**	**128,000**
C Scopes - Operational Compliance Upgrades				-
				-
		-	-	-
D Scopes - Critical Safety and Reliability Improvements				-
	Control Narrative Asbuilt	17,850		18,000
		17,850	**-**	**18,000**
E Scopes - Integrity Management Plan Requirements				-
	External Inspect Amine and Dehy Reboilers, and Glycol Heating System Burner	15,150		15,150
	Tank Inspections (Waste Liquids Tank and Verify Flare Drain Tank)	13,900		13,900
	Amine Reflux Accumulator and Regenerator External Inspection	7,000		7,000
	Inspect Amine Asborber Tower and V-104 Dehy Contactor	14,000		14,000
		50,000	**-**	**50,000**
F Scopes - Hazop Close-out (shutdown required)				-
	PSV MOCs - Replace 2020-1 with NACE PSV	3,500		3,500
	Liquids Drain Tank - PM Vacuum Breaker Only	6,500		6,500
	P&ID Update	29,400		29,400
		39,000	**-**	**39,000**
				-
				-
X Scopes - Plant Outage Activities				-
	Turnaround OH, QA/AC Doc Control, Safety, Coordinators	43,275		43,275
	Medic - 10 days	34,500		34,500
	Air Trailer 3 days	22,300		22,300
	Wash Car	8,700		8,700
	PNG Safety Consultant	15,000		15,000
Part of T/O	Train Wash (including drain, de-pressure and purge after wash) - Steam Only	29,900		29,900
	Plant Shutdown, Gas Off, LOTO Inlet and Outlet	29,626		29,626
	Contractor Commissioning Support (S2F)	24,872		24,872
	Gas On	7,555		7,555
	Turnvover Documnetation	6,393		6,393
	Other (2) - Hydrovac standby and disposal	27,100		27,100
Engineering and Procurement		30,000	-	30,000
PM		90,000	-	90,000
TA Planning		85,692		85,692
PST		1,000		1,000
		456,000	**-**	**456,000**
Subtotal		**691,000**	**-**	**691,000**
Contingency		317,000		317,000
Total CAPEX		**1,008,000**	**-**	**1,008,000**

TRGP Capital and O&M Estimate Summary -2025 Work Scope

Capital

	2025	Total
A Scopes - End of Life Asset Replacement		
Replace Amine Absorber Tower and Trays	450,500	450,500
	451,000	**451,000**
B Scopes - Deteriorated Asset Repair		-
Replace Above-Ground Corroded Piping	58,500	58,500
HMI/PLC back pane IO terminal strips	16,500	16,500
Flare Tip Repair or Replace	37,500	37,500
Control Valve Internal Inspections and Repairs	34,000	34,000
Replace drain valve on H-103	2,500	2,500
Replace Lean-Rich Amine Exchanger Plate Pack	10,500	10,500
PM Amine Circulating Pumps	24,800	24,800
Replace Amine Charge Pumps	13,150	13,150
	197,000	**197,000**
C Scopes - Operational Compliance Upgrades		-
Sales Pipeline - Blinds, Valves, and Filter	245,000	245,000
Outlet H2S Analyzer	36,500	36,500
Inlet H2S Analyzer	36,500	36,500
Pipeline Isolation and Blinding	37,800	37,800
Sale gas dew point analyzer	38,000	38,000
Install Flare Gas Meter - Fuel Gas Meter	10,500	10,500
Add PSV Protection to Mercaptan Tank	4,500	4,500
Flare Blackening	52,100	52,100
Programming PLC/HMI Safegourds to prevent reoccurence of high DP Surges	5,850	5,850
	467,000	**467,000**
D Scopes - Critical Safety and Reliability Improvements		-
PM PVRV - Liquid Drains Tank	6,500	6,500
Plant Specifications Update	17,000	17,000
Re-Route H-101 Fuel Tubing on Boiler	3,500	3,500
Blowdown to flare - Mercaptan Tank Site Glass	2,500	2,500
Replace ball valve with globe valve F-101	3,500	3,500
TEG Dehy #1 Cold Start-up Bypass	6,500	6,500
Replace building H2S alarm beacon lenses to blue	6,250	6,250
Guy wire impsection for flare stack	9,600	9,600
Emergency Generator Deficiencies - Fuel Filter and ESD Hardwire	8,000	8,000
	63,000	**63,000**
E Scopes - Integrity Management Plan Requirements		-
Cooler/Condenser Headerbox and Tube Inspections	14,800	14,800
Inspect Amine and Dehy Reboilers, and Glycol Heating System Burner	81,350	81,350
Amine Regenerator, Amine Reflux Tower, and Flare KO Drum Detailed Inspections	19,000	19,000
Tank Inspections (Hydrovac Flare Drain Tank)	18,500	18,500
Replace/Retrim Fuel Gas Regulators	4,450	4,450

	Amine charcoal filter - reconfigure PSV piping	3,500	3,500
	Remove and Cap 2" Raw Gas Fuel Startup	14,200	14,200
		156,000	**156,000**
F Scopes - Hazop Close-out (shutdown required)			-
	Re-Route H-101 Sweep Gas	8,050	8,050
	Install Purge Gas for Amine Filters	16,100	16,100
	F-104 Glycol Filter Piping Defiencies	4,500	4,500
	H2S Detection Aerial Cooler	30,800	30,800
	Install TEG Absorber Low Level ESD Actuator	11,400	11,400
	Hardwore ESD Buttons to SD Relays	11,675	11,675
	Install trunk JB and Trunk Cables	5,850	5,850
	Control system verifications - H2S ESD, LSL/TSH-600, PAL-401, LSL/LSH-400	6,600	6,600
	H2S Analyzer Low Pressure Switch	2,500	2,500
	Install Amine Absorber Low Level ESD Actuator	12,600	12,600
		110,000	**110,000**
			-
			-
X Scopes - Plant Outage Activities			-
	Turnaround OH, QA/AC Doc Control, Safety, Coordinators	165,000	165,000
	Train Wash - includes caustic, acid and amine tank and disposal	120,900	120,900
	Plant Shutdown, Gas Off, LOTO Inlet and Outlet, Drain, Purge	43,500	43,500
	Dry Commissioning	32,480	32,480
	Wet Commissioning Support (S2F)	29,100	29,100
	Gas On Operations Support	22,100	22,100
	Handover Docs and Closeout	7,850	7,850
	Refill Amine, HMS glycol, and TEG Systems	75,250	75,250
	Medic, Air Trailer, Bottle Watch, Hole Watch - 14 days medic and 6 days air trailer and safety watch	82,800	82,800
	Wash car, Utilities	10,700	10,700
	PNG Safety	15,000	15,000
	Other (2) - Vac Truck Standby and Disposal	57,700	57,700
		662,000	**662,000**
Engineering and Procurement		290,000	290,000
PM		140,000	140,000
TA Planning		146,650	146,650
PST		46,000	46,000
Subtotal		**2,729,000**	**2,729,000**
Contingency		1,181,000	1,181,000
Total CAPEX		**3,910,000**	**3,910,000**

APPENDIX B – DOCUMENTATION SUPPORTING 2024 ESTIMATES

- 01-A – Sureline Reflux Piping Estimate
- 01-B - PNG Piping WT Iris E-EDM240224.1
- 01-C - PNG July 29 – reflux pump repair – Service Onsite
- 01-D- PNG July 24 – Reflux Pump Replace – Service Onsite
- 02-A – PNG – EICA Asuiblt WSP Proposal R1
- 02-B – WSP As-builts CO-001 – Signed
- 03-A – PNG E-EDM240298 – Pre TA Vessel Inpsection
- 03-B – D5068 Quote – 09GLBC – PNG TRGP Scaffold
- 03-C – L24074 PNG Tumbler UT Inspection Insulation
- 04-A – Kings Energy PSV2020-01 Pricing
- 05-A – PNG-S2F-DLN24-Estimate-Execution July 3
- 05-B – Trojan – Medical Safety Services (2024.07.18)
- 05-C – HALO Hazardous Material Sampling
- 05-D – CopperTip – N2 Purge Gas Estimate
- 06-A – PNG-S2F-DLB24-Estimate-PlanningJune27
- 06-B – LaurenServices – 2024 TRGP TA Reflux Piping Mods
- 06-C – Lauren – 2024 TRGP TA PM Support

The foregoing documents pertaining to cost estimates have been excluded from the Application. PNG(NE) considers that this information should be kept confidential on the basis that PNG(NE) expects to seek competitive bids for the materials and construction work required to execute the Project, and disclosure of the estimated costs for the materials and construction work would prejudice PNG(NE)'s negotiating position and competitive tendering processes.

APPENDIX C – DOCUMENTATION SUPPORTING 2025 ESTIMATES

- 01-A – Foremost – Amine Absorber – Q03-004850-1
- 01-B – Koch – Amine Absorber Trays – 406059 Quotation Rev1.0
- 02-A – ServiceOnsite – Amine Charge Pump
- 02-B – WCE – Amine Exchanger Plate Replacement
- 05-A – Warco – Bundle Pulling Quote W240009
- 07-A – S2F – rev1-PNG-High_Level-Estimate-Execution2025
- 07-B – Avenge – Amine 3 Stage Circulation Estimate
- 08-A – S2F – Planning Estimate 20242025
- 08-B – Lauren – 2025 Engineering Estimate

The foregoing documents pertaining to cost estimates have been excluded from the Application. PNG(NE) considers that this information should be kept confidential on the basis that PNG(NE) expects to seek competitive bids for the materials and construction work required to execute the Project, and disclosure of the estimated costs for the materials and construction work would prejudice PNG(NE)'s negotiating position and competitive tendering processes.

APPENDIX D – CONTINGENCY – RESULTS OF MONTE CARLO EXERCISE

FINAL Cost Risk Results - TRGP Capital and OM Cost Risk Assessment

25-Jul-24

Risk Methodology

The two risk inputs are (1) cost estimate uncertainty ranges (based on Class of estimate and AACE accuracy ranges) and (2) project specific event risks

2024 Scope

Basis of Risk Analysis

CAPITAL	$	689,983	Excludes Contingency
O&M	$	52,950	Excludes Contingency
TOTAL	$	742,933	Excludes Contingency

WEIGHTED AVERAGE - CLASS OF ESTIMATE

CAPITAL	Class 2.71
O&M	Class 3.07
TOTAL	Class 2.73

CAPITAL - Quantitative Cost Risk Assessment Summary Table

	Cost Estimate Range Uncertainty			Project-Specific Risk (Risk Register)		Total Cost Risk		
P-Value / Confidence Level	Cost Estimate Uncertainty (incl. deterministic cost)	Net Cost Estimate Uncertainty	Estimate Range %	Event Risk Cost	Event Risk %	Total Net Cost Risk	Total Probabilistic Cost	Net Cost Risk %
5%	$616,465	-$73,518	-11%	$35,525	5%	-$37,993	$651,990	-6%
10%	$631,623	-$58,360	-8%	$44,653	6%	-$13,707	$676,276	-2%
15%	$643,918	-$46,065	-7%	$55,011	8%	$8,945	$698,928	1%
20%	$655,481	-$34,502	-5%	$64,218	9%	$29,715	$719,698	4%
25%	$666,409	-$23,574	-3%	$72,682	11%	$49,109	$739,092	7%
30%	$677,143	-$12,840	-2%	$81,682	12%	$68,842	$758,825	10%
35%	$686,807	-$3,176	0%	$89,702	13%	$86,526	$776,509	13%
40%	$696,856	$6,873	1%	$98,803	14%	$105,675	$795,658	15%
45%	$703,544	$13,561	2%	$107,785	16%	$121,346	$811,329	18%
50%	$709,980	$19,997	3%	$116,620	17%	$136,618	$826,601	20%
55%	$716,180	$26,197	4%	$125,966	18%	$152,163	$842,146	22%
60%	$729,732	$39,749	6%	$135,106	20%	$174,855	$864,838	25%
65%	$739,864	$49,881	7%	$145,349	21%	$195,230	$885,213	28%
70%	$750,314	$60,331	9%	$155,652	23%	$215,983	$905,966	31%
75%	$761,353	$71,370	10%	$166,671	24%	$238,041	$928,024	34%
80%	$773,186	$83,203	12%	$177,658	26%	$260,861	$950,844	38%
85%	$785,841	$95,858	14%	$191,366	28%	$287,224	$977,207	42%
90%	$799,109	$109,126	16%	$207,451	30%	$316,577	$1,006,560	46%
95%	$814,681	$124,698	18%	$231,881	34%	$356,579	$1,046,562	52%
Deterministic Cost	$ 689,983							

O&M - Quantitative Cost Risk Assessment Summary Table

	Cost Estimate Range Uncertainty			Project-Specific Risk (Risk Register)		Total Cost Risk		
P-Value / Confidence Level	Cost Estimate Uncertainty (incl. deterministic cost)	Net Cost Estimate Uncertainty	Estimate Range %	Event Risk Cost	Event Risk %	Total Net Cost Risk	Total Probabilistic Cost	Net Cost Risk %
5%	$45,550	-$7,400	-14%	$0	0%	-$7,400	$45,550	-14%
10%	$47,056	-$5,894	-11%	$0	0%	-$5,894	$47,056	-11%
15%	$48,263	-$4,687	-9%	$0	0%	-$4,687	$48,263	-9%
20%	$49,405	-$3,545	-7%	$0	0%	-$3,545	$49,405	-7%
25%	$50,454	-$2,496	-5%	$0	0%	-$2,496	$50,454	-5%
30%	$51,455	-$1,495	-3%	$0	0%	-$1,495	$51,455	-3%
35%	$52,452	-$498	-1%	$0	0%	-$498	$52,452	-1%
40%	$53,374	$424	1%	$0	0%	$424	$53,374	1%
45%	$54,098	$1,148	2%	$0	0%	$1,148	$54,098	2%
50%	$54,744	$1,794	3%	$0	0%	$1,794	$54,744	3%
55%	$55,439	$2,489	5%	$0	0%	$2,489	$55,439	5%
60%	$56,684	$3,734	7%	$0	0%	$3,734	$56,684	7%
65%	$57,621	$4,671	9%	$0	0%	$4,671	$57,621	9%
70%	$58,643	$5,693	11%	$0	0%	$5,693	$58,643	11%
75%	$59,660	$6,710	13%	$0	0%	$6,710	$59,660	13%
80%	$60,742	$7,792	15%	$0	0%	$7,792	$60,742	15%
85%	$61,961	$9,011	17%	$0	0%	$9,011	$61,961	17%
90%	$63,389	$10,439	20%	$0	0%	$10,439	$63,389	20%
95%	$65,029	$12,079	23%	$0	0%	$12,079	$65,029	23%
Deterministic Cost	$ 52,950							

TOTAL - Quantitative Cost Risk Assessment Summary Table

	Cost Estimate Range Uncertainty			Project-Specific Risk (Risk Register)		Total Cost Risk		
P-Value / Confidence Level	Cost Estimate Uncertainty (incl. deterministic cost)	Net Cost Estimate Uncertainty	Estimate Range %	Event Risk Cost	Event Risk %	Total Net Cost Risk	Total Probabilistic Cost	Net Cost Risk %
5%	$662,015	-$80,918	-11%	$35,525	5%	-$45,393	$697,540	-6%
10%	$678,679	-$64,254	-9%	$44,653	6%	-$19,601	$723,332	-3%
15%	$692,180	-$50,753	-7%	$55,011	8%	$4,258	$747,191	1%
20%	$704,885	-$38,048	-5%	$64,218	9%	$26,170	$769,103	4%
25%	$716,863	-$26,070	-4%	$72,682	11%	$46,613	$789,546	6%
30%	$728,599	-$14,334	-2%	$81,682	12%	$67,347	$810,280	9%
35%	$739,259	-$3,674	0%	$89,702	13%	$86,028	$828,961	12%
40%	$750,229	$7,296	1%	$98,803	14%	$106,099	$849,032	14%
45%	$757,643	$14,710	2%	$107,785	16%	$122,494	$865,427	16%
50%	$764,725	$21,792	3%	$116,620	17%	$138,412	$881,345	19%
55%	$771,618	$28,685	4%	$125,966	18%	$154,651	$897,584	21%
60%	$786,416	$43,483	6%	$135,106	20%	$178,589	$921,522	24%
65%	$797,485	$54,552	7%	$145,349	21%	$199,901	$942,834	27%
70%	$808,958	$66,025	9%	$155,652	23%	$221,676	$964,609	30%
75%	$821,012	$78,079	11%	$166,671	24%	$244,751	$987,684	33%
80%	$833,928	$90,995	12%	$177,658	26%	$268,653	$1,011,586	36%
85%	$847,802	$104,869	14%	$191,366	28%	$296,235	$1,039,168	40%

90%	$862,499	$119,566	16%	$207,451	30%	**$327,016**	**$1,069,949**	**44%**
95%	$879,709	$136,776	18%	$231,881	34%	**$368,657**	**$1,111,590**	**50%**
Deterministic Cost	**$ 742,933**							

Top 5 Cost Estimate Range Drivers

Estimate Item / Category	Deterministic Cost Estimate	Min %	Max%	Approx. Net P90 Cost Risk	Comment
Capital - 2024 PM	$ 90,000	-20%	30%	$ 14,739	Class 3 Estimate
Capital - 2024 TA Planning	$ 85,692	-20%	30%	$ 14,030	Class 3 Estimate
Capital - 2024-B - Job #18 - Replace Amine Reflux discharge piping. Increase the piping diameter to 2" standard for reflux lines.	$ 57,650	-15%	20%	$ 6,186	Class 2 Estimate
Capital - 2024-X - Job #536 - OFA3 Medics, 10 days	$ 34,500	-20%	30%	$ 5,650	Class 3 Estimate
Capital - 2024 Engineering and Procurement	$ 30,000	-20%	30%	$ 4,911	Class 3 Estimate

Top 5 Risk Register / Event Risk Drivers

Risk	Probability	Impact	Approximate Net P90 Cost Risk	Comment
2024-E - Job #120 - Inspection. V-100 Amine absober tower UPPER, above chimney tray. boroscope, NDE/UT Risk: Found work. Trays in this tower known to be damaged and out of place. Risk/concern is that inspection may find areas requiring close evaluation, such as tray parts fretting against the shell which can compromise the shell integrity in localized areas. The tower is deemed not operable in found condition. 1. The planned visual inspection by boroscope camera will identify areas of concern. 2. external UT grid in areas of concern. 3. Queue and have available an engineering service to perform fit for service assessment based on found condtion. 4. Have an engineered repair plan prepared for such a scenario. 5. Localized repair. 6. Do nothing, bypass the amine plant	10% - 35%	$3,000 - $88,000	$ 39,262	1. included in plan and contingencies 2. included in the plan and contingencies 3. ~2K 4. ~2K 5. 0 - 80K 6. TBD - options report in progress
2024-E - Job #121 - Inspection. V-100 Amine absober tower BOTTOM, sump below chimney tray. Risk: Found work. Trays are known to be damaged and out of place. Risk/concern is that inspection may find areas requiring close evaluation, such as tray parts fretting against the shell which can compromise the shell integrity in localized areas. The tower is deemed not operable in found condition.1. The planned visual inspection by boroscope camera will identify areas of concern. 2. external UT grid in areas of concern. 3. Queue and have available an engineering service to perform fit for service assessment based on found condtion. 4. Have an engineered repair plan prepared for such a scenario. 5. Localized repair. 6. Do nothing, bypass the amine plant	10% - 35%	$3,000 - $88,000	$ 39,121	1. included in plan and contingencies 2. included in the plan and contingencies 3. ~2K 4. ~2K 5. 0 - 80K 6. TBD - options report in progress
2024-E - Job #127 - Inspection. V-104 Dehy TEG Contactor BOTTOM High pressure cleaning External Visual Internal Visual. Risk: REPAIR 2a.external UT grid in areas of concern. 2b Queue and have available an engineering service to perform fit for service assessment based on found condtion and achievable repair. 2c. have an engineered repair plan prepared for such a scenario.	10% - 30%	$1,500 - $83,500	$ 35,428	REPAIR 2a. included in the plan and contingencies 2b ~2500 2c 0-80k
2024-B - Job #136 - Corroded piping RT and UT survey. Risk: Inspection results may bring 2025 deferred piping replacement back to the 2024 scope	35% - 65%	$0 - $45,000	$ 25,226	$0-45000

2024-E - Job #127 - Inspection. V-104 Dehy TEG Contactor BOTTOM High pressure cleaning External Visual Internal Visual. Risk: Wash 1. There is currently no plan to chem wash the dehydration tower and system. The planned visual inspection by boroscope may find the tower and trays fouled, requiring cleaning.	55% - 75%	$0 - $40,000	$ 23,836	WASH 1a. included in plan and contingencies 1b. 0-40K, service will already be onsite. 2a. included in the plan and contingencies

SUMMARY OF RESULTS

The basis of the risk analysis is the total 2024 cost of $742,933; this value excludes contingency. This is comprised of $689,983 of capital cost and $52,950 of O&M. The total cost, without any contingency has a 14% confidence level (86% chance of the cost being greater then $742,933)

The probabilistic range of outcomes is from a 6% underrun to a 50% overrun around the $742,933 base cost (5% confidence to 95% confidence range).

The current planned contingency of $193,043 (from the estimate summary sheet) carries a 64% confidence level based on this assessment.

FINAL Cost Risk Results - TRGP Capital and OM Cost Risk Assessment

25-Jul-24

Risk Methodology

The two risk inputs are (1) cost estimate uncertainty ranges (based on Class of estimate and AACE accuracy ranges) and (2) project specific event risks

2025 Scope

Basis of Risk Analysis

CAPITAL	$	2,682,955	Excludes Contingency
O&M	$	33,700	Excludes Contingency
TOTAL	$	2,716,655	Excludes Contingency

WEIGHTED AVERAGE - CLASS OF ESTIMATE

CAPITAL	Class 3.24
O&M	Class 3.93
TOTAL	Class 3.25

CAPITAL - Quantitative Cost Risk Assessment Summary Table

	Cost Estimate Range Uncertainty			Project-Specific Risk (Risk Register)		Total Cost Risk		
P-Value / Confidence Level	Cost Estimate Uncertainty (incl. deterministic cost)	Net Cost Estimate Uncertainty	Estimate Range %	Event Risk Cost	Event Risk %	Total Net Cost Risk	Total Probabilistic Cost	Net Cost Risk %
5%	$2,387,357	-$295,598	-11%	$106,777	4%	-$188,820	$2,494,135	-7%
10%	$2,456,666	-$226,289	-8%	$131,187	5%	-$95,102	$2,587,853	-4%
15%	$2,513,838	-$169,117	-6%	$151,763	6%	-$17,354	$2,665,601	-1%
20%	$2,567,431	-$115,524	-4%	$171,820	6%	$56,296	$2,739,251	2%
25%	$2,615,939	-$67,016	-2%	$190,897	7%	$123,881	$2,806,836	5%
30%	$2,662,267	-$20,688	-1%	$210,178	8%	$189,491	$2,872,446	7%
35%	$2,706,226	$23,271	1%	$230,726	9%	$253,997	$2,936,952	9%
40%	$2,750,825	$67,870	3%	$251,714	9%	$319,584	$3,002,539	12%
45%	$2,782,597	$99,642	4%	$275,979	10%	$375,621	$3,058,576	14%
50%	$2,812,886	$129,931	5%	$311,419	12%	$441,350	$3,124,305	16%
55%	$2,843,406	$160,451	6%	$355,426	13%	$515,877	$3,198,832	19%
60%	$2,900,241	$217,286	8%	$392,364	15%	$609,650	$3,292,605	23%
65%	$2,945,211	$262,256	10%	$428,933	16%	$691,189	$3,374,144	26%
70%	$2,992,489	$309,534	12%	$460,878	17%	$770,412	$3,453,367	29%
75%	$3,043,695	$360,740	13%	$496,588	19%	$857,328	$3,540,283	32%
80%	$3,095,872	$412,917	15%	$545,309	20%	$958,226	$3,641,181	36%
85%	$3,150,309	$467,354	17%	$602,403	22%	$1,069,757	$3,752,712	40%
90%	$3,208,414	$525,459	20%	$655,280	24%	$1,180,739	$3,863,694	44%
95%	$3,292,202	$609,247	23%	$737,110	27%	$1,346,357	$4,029,312	50%
Deterministic Cost	$ 2,682,955							

O&M - Quantitative Cost Risk Assessment Summary Table

	Cost Estimate Range Uncertainty			Project-Specific Risk (Risk Register)		Total Cost Risk		
P-Value / Confidence Level	Cost Estimate Uncertainty (incl. deterministic cost)	Net Cost Estimate Uncertainty	Estimate Range %	Event Risk Cost	Event Risk %	Total Net Cost Risk	Total Probabilistic Cost	Net Cost Risk %
5%	$25,504	-$8,196	-24%	$0	0%	-$8,196	$25,504	-24%
10%	$27,198	-$6,502	-19%	$0	0%	-$6,502	$27,198	-19%
15%	$28,618	-$5,082	-15%	$0	0%	-$5,082	$28,618	-15%
20%	$29,747	-$3,953	-12%	$0	0%	-$3,953	$29,747	-12%
25%	$30,840	-$2,860	-8%	$0	0%	-$2,860	$30,840	-8%
30%	$31,844	-$1,856	-6%	$0	0%	-$1,856	$31,844	-6%
35%	$32,765	-$935	-3%	$0	0%	-$935	$32,765	-3%
40%	$33,840	$140	0%	$0	0%	$140	$33,840	0%
45%	$34,668	$968	3%	$0	0%	$968	$34,668	3%
50%	$35,545	$1,845	5%	$0	0%	$1,845	$35,545	5%
55%	$36,448	$2,748	8%	$0	0%	$2,748	$36,448	8%
60%	$37,667	$3,967	12%	$0	0%	$3,967	$37,667	12%
65%	$38,729	$5,029	15%	$0	0%	$5,029	$38,729	15%
70%	$39,821	$6,121	18%	$0	0%	$6,121	$39,821	18%
75%	$41,049	$7,349	22%	$0	0%	$7,349	$41,049	22%
80%	$42,340	$8,640	26%	$0	0%	$8,640	$42,340	26%
85%	$43,892	$10,192	30%	$0	0%	$10,192	$43,892	30%
90%	$45,544	$11,844	35%	$0	0%	$11,844	$45,544	35%
95%	$47,556	$13,856	41%	$0	0%	$13,856	$47,556	41%
Deterministic Cost	$ 33,700							

TOTAL - Quantitative Cost Risk Assessment Summary Table

	Cost Estimate Range Uncertainty			Project-Specific Risk (Risk Register)		Total Cost Risk		
P-Value / Confidence Level	Cost Estimate Uncertainty (incl. deterministic cost)	Net Cost Estimate Uncertainty	Estimate Range %	Event Risk Cost	Event Risk %	Total Net Cost Risk	Total Probabilistic Cost	Net Cost Risk %
5%	$2,412,861	-$303,794	-11%	$106,777	4%	-$197,017	$2,519,638	-7%
10%	$2,483,865	-$232,790	-9%	$131,187	5%	-$101,603	$2,615,052	-4%
15%	$2,542,455	-$174,200	-6%	$151,763	6%	-$22,437	$2,694,218	-1%
20%	$2,597,178	-$119,477	-4%	$171,820	6%	$52,343	$2,768,998	2%
25%	$2,646,780	-$69,875	-3%	$190,897	7%	$121,021	$2,837,676	4%
30%	$2,694,112	-$22,543	-1%	$210,178	8%	$187,635	$2,904,290	7%
35%	$2,738,991	$22,336	1%	$230,726	9%	$253,062	$2,969,717	9%
40%	$2,784,665	$68,010	3%	$251,714	9%	$319,724	$3,036,379	12%
45%	$2,817,265	$100,610	4%	$275,979	10%	$376,589	$3,093,244	14%
50%	$2,848,430	$131,775	5%	$311,419	12%	$443,194	$3,159,849	16%
55%	$2,879,854	$163,199	6%	$355,426	13%	$518,625	$3,235,280	19%
60%	$2,937,908	$221,253	8%	$392,364	15%	$613,617	$3,330,272	23%
65%	$2,983,940	$267,285	10%	$428,933	16%	$696,218	$3,412,873	26%
70%	$3,032,310	$315,655	12%	$460,878	17%	$776,533	$3,493,188	29%
75%	$3,084,745	$368,090	14%	$496,588	19%	$864,677	$3,581,332	32%

80%	$3,138,213	$421,558	16%	$545,309	20%	**$966,867**	**$3,683,522**	**36%**
85%	$3,194,201	$477,546	18%	$602,403	22%	**$1,079,949**	**$3,796,604**	**40%**
90%	$3,253,958	$537,303	20%	$655,280	24%	**$1,192,583**	**$3,909,238**	**44%**
95%	$3,339,759	$623,104	23%	$737,110	27%	**$1,360,213**	**$4,076,868**	**50%**
Deterministic Cost	**$ 2,716,655**							

Top 5 Cost Estimate Range Drivers

Estimate Item / Category	Deterministic Cost Estimate	Min %	Max%	Approx. Net P90 Cost Risk	Comment
Capital - 2025-C - Job #279 - Sales pipeline gas filter. Install sales gas filter. 2025	$ 220,000	-50%	100%	$ 113,547	Class 5 Estimate
Capital - 2025-A - Job #2 - Amine Tower Replace, Review current realities of gas demand for the plant. Redesign processing equipment to updated design basis parameters for gas rate and inlet compostion.	$ 450,500	-20%	30%	$ 67,397	Class 3 Estimate
Capital - 2025 Engineering and Procurement	$ 290,000	-20%	30%	$ 43,376	Class 3 Estimate
Capital - 2025-X - Job #552 - 2025 Execution per Jun20 scrub scope. Construction, coordination, support, oversight. S2F site execution phase	$ 165,000	-20%	30%	$ 24,679	Class 3 Estimate
Capital - 2025 TA Planning	$ 146,650	-20%	30%	$ 21,939	Class 3 Estimate

Top 5 Risk Register / Event Risk Drivers

Risk	Probability	Impact	Approximate Net P90 Cost Risk	Comment
2025-E - Job #115 - Inspection H-100 amine reboiler. This will be the largest inspection scope of the outage. Requires specialised services to setup the deck to pull and cradle the firetube bundles to enable access to the shell and the fire tubes Risk: Found work, excess corrosion 1. Below Tmin Pitting or swathing corrosion of vapour space of the shell above liquid level. 2. Large areas below Tmin, not practical to repair. 3. Fire tube damage from historical low level in the boiler, corrosion or hot spots	10% - 20%	$183,750 - $367,500	$ 201,196	1. within existing contingency 2a. Should be within existing contingency 2b. Get quote placeholder from the OEM (Foremost) for shell. ~180K plus installation, 2025. ** Assume installation $20K. 3. materials should be within existing contingency. Welder/fabricator for 3 days to replace sections of tube ~15K
2025-E - Job #139 - H-103 HMS EG Reboliler External NDE Inspection Risk: Found work, excess corrosion 1. Below Tmin Pitting or swathing corrosion of vapour space of the shell above liquid level. 2. Large areas below Tmin, not practical to repair. 3. Fire tube damage from historical low level in the boiler, corrosion or hot spots	10% - 20%	$105,000 - $210,500	$ 113,649	1. within existing contingency 2a. Should be within existing contingency 2b. Get quote placeholder from the OEM (Foremost) for shell. ~80K plus installation, 2025. Assume installation is $20K. 3. materials should be within existing contingency. Welder/fabricator for 2 days to replace sections of tube ~10K
2025-E - Job #116 - Inspection H-101 TEG dehy reboiler. This. Requires specialised services to setup the deck to pull and cradle the firetube bundles to enable access to the shell and the fire tubes Risk: Found work, excess corrosion 1. Prepare a welding deposit-thickness buildup procedure to address pitting and small area build-up. 2a. Queue and have available an engineering service to perform fit for service assessment based on found condtion and achievable repairs. Deem the repairs temporary or temp-permanent. 2b. Replace the reboiler shell 2025 if assessment fails to extend the life of the vessel. 3. Prepare an at the ready welding procedure and material specifications to replace sections of the firetubes (simple pipe)	10% - 20%	$101,250 - $202,500	$ 110,067	1. within existing contingency 2a. Should be within existing contingency 2b. Get quote placeholder from the OEM (Foremost) for shell. ~80K plus installation, 2025. Assume installation $50K. 3. materials should be within existing contingency. Welder/fabricator for 1 days to replace sections of tube ~5K

2025-E - Job #122 - Inspection. V-101 Amine regenerator UPPER **High pressure cleaning** **Risk: Found work, excess corrosion.** **1. Prepare a welding deposit-thickness buildup procedure to address pitting and small area build-up where accessible and practical** **2a. Queue and have available an engineering service to perform fit for service assessment based on found condition and achievable repairs. Deem the repairs temporary or permanent.** **3. Do nothing wrt trays in 2024. Replace trays cartridge set in 2025.**	**10% - 20%**	**$61,875 - $123,750**	**$ 67,198**	**1. within existing contingency** **2a. ~2500** **3. In 2025, ~80K**
2025-E - Job #129 - Inspection V-107 Flare KO Drum, LOWER **Risk: Found work, excess corrosion.** **1. Prepare a welding deposit-thickness buildup or repad procedure to address pitting and small area build-up where accessible and practical** **2. Queue and have available an engineering service to perform fit for service assessment based on found condition and achievable repairs. Deem the repairs temporary or permanent**	**65% - 100%**	**$16,875 - $25,000**	**$ 18,613**	**1 within existing contingency** **2a. Assessment ~2500** **2b. Repairs ~15-20K**

SUMMARY OF RESULTS

The basis of the risk analysis is the total 2025 cost of $2,716,655; this value excludes contingency. This is comprised of $2,682,955 of capital cost and $33,700 of O&M. The total cost, without any contingency has a 19% confidence level (81% chance of the cost being greater then $2,716,655)

The probabilistic range of outcomes is from a 7% underrun to a 50% overrun around the $2,716,655 base cost (5% confidence to 95% confidence range).

The current planned contingency of $1,083,137 (from the estimate summary sheet) carries an 86% confidence level based on this assessment.

Appendix D – Risk Register (Confidential)