PACIFIC NORTHERN GAS

Verlon G. Otto
Director, Regulatory Affairs

Pacific Northern Gas Ltd.
750 – 888 Dunsmuir Street
Vancouver, BC V6C 3K4
Tel: (604) 691-5680
Fax: (604) 697-6210
Email: votto@png.ca

Via E-File

February 23, 2021

B.C. Utilities Commission
Suite 410 - 900 Howe Street
Vancouver, BC V6Z 2N3

File No.: 4.2 (2021)

Attention: Patrick Wruck
Commission Secretary

Dear Mr. Wruck:

Re: Pacific Northern Gas Ltd.
Application for a Certificate of Public Convenience and Necessity for the Salvus to Galloway Gas Line Upgrade Project
Response to BCUC Information Request No. 2

Accompanying, please find the response of Pacific Northern Gas Ltd. (PNG) to the referenced information request.

In addition, PNG would like to take this opportunity to clarify its intentions for the accounting of Salvus to Galloway Project (Project) capital expenditures planned for 2021 and requests consideration of the discussion that follows.

Return on 2021 Capital Expenditures Placed into Service in 2021

Section 7.2.3, AFUDC on Work in Progress, of PNG's Application highlights that there are multiple discrete undertakings associated with the Project and that the majority of capital expenditures will be placed into service in the year that the capital is spent. Further, Section 7.2.3 observes that capital expenditures carried over into a future period will be accounted for as work in progress and, in accordance with PNG's established practice, will attract Allowance for Funds Used During Construction (AFUDC) at PNG's after-tax weighted average cost of capital.

It has come to PNG's attention that, pending CPCN approval, it may not have been entirely clear how PNG intends to capture the allowed return on project capital costs that are both incurred and placed into service in 2021, particularly given that there is no clear mechanism

to do so as PNG's delivery rates for 2021 have already been established and do not reflect the inclusion of any of the project-related capital expenditures.

As a mechanism to remedy this peculiar circumstance, PNG is proposing that all 2021 capital expenditures be accounted for as work in progress during 2021 and be permitted to attract AFUDC in 2021. Subsequently, any project assets identified as being placed in service during 2021 would then be transferred to assets in service at the end of 2021, and thus properly reflected in 2022 opening rate base balances for the purposes of PNG's next revenue requirements application.

For illustrative purposes, PNG provides the following example of the potential AFUDC associated with the planned project capital spend for 2021 of $24.8 million under two different capital spending profiles. As illustrated, PNG estimates AFUDC on the 2021 capital expenditures could be in the range of $375,000 to $500,000, with only a portion of this attributable to capital spending on assets also placed into service in 2021.

Scenario	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
Annual AFUDC Rate*	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%	
Illustrative Capital Spend 1							
S2G Capital Spend	$2,760,318	$2,760,318	$2,760,318	$5,520,637	$5,520,637	$5,520,637	$24,842,865
Cumulative Capital Spend	$2,760,318	$5,520,637	$8,280,955	$13,801,592	$19,322,228	$24,842,865	
AFUDC on WIP Balances	$14,022	$28,044	$42,067	$70,111	$98,155	$126,200	**$378,599**
Illustrative Capital Spend 2							
S2G Capital Spend	$5,520,637	$5,520,637	$5,520,637	$2,760,318	$2,760,318	$2,760,318	$24,842,865
Cumulative Capital Spend	$5,520,637	$11,041,273	$16,561,910	$19,322,228	$22,082,547	$24,842,865	
AFUDC on WIP Balances	$28,044	$56,089	$84,133	$98,155	$112,178	$126,200	**$504,799**

*Annual AFUDC Rate is the approved 2021 after-tax weighted average cost of capital

Please direct any questions regarding the application to my attention.

Yours truly,

Original on file signed by:

Verlon G. Otto

Encl.

Pacific Northern Gas Ltd.
Application for a Certificate of Public Convenience and Necessity for the Salvus to Galloway Gas Line Upgrade Project

INFORMATION REQUEST NO. 2 TO PACIFIC NORTHERN GAS LTD.

Table of Contents **Page no.**

A. HISTORY AND CONTEXT OF APPLICATION

43.0 Reference: HISTORY AND CONTEXT OF APPLICATION
Exhibit B-2, BCUC IR 3.1.1, 3.2; PNG West 2020-2021 RRA proceeding, Exhibit B-7, Attachment BCUC 103.1d
BC Oil and Gas Commission (BC OGC) Ongoing Reviews and Audits

In response to British Columbia Utilities Commission (BCUC) Information Request (IR) 3.1.1, regarding whether the outcomes of BC OGC's aged pipeline review would impact the scope of work proposed within this Application for a Certificate of Public Convenience and Necessity for the Salvus to Galloway Gas Line Upgrade Project (Application), Pacific Northern Gas Ltd. (PNG) stated:

> PNG notes that the scope of work proposed within this Application meets the intent of maintenance of safe and reliable gas service through the execution of pipeline integrity management improvement and hazard reduction to the degree it is practicable through the application of the 'As Low As Reasonably Practicable' (ALARP) approach. As such, the work proposed within the scope of the Application is required by CSA Z662 and is independent of any final outcomes related to ongoing and/or future initiatives by the BC OGC.

43.1 Please clarify whether the BC OGC has provided PNG with an anticipated date by which the review of PNG's aged pipeline assets will be complete. If so, when?

Response:

A completion date for the review of PNG's aged pipeline assets has not been provided by the BC OGC. Comprehensive engineering assessments for review of each of the pipeline segment are due to the BC OGC by June 2021. The results of these assessments will be inputs to the BC OGC's subsequent review process. As a result, the BC OGC review and discussion around any outcomes is not expected to be completed until at least late in the third quarter of 2021.

In response to BCUC IR 3.2, PNG stated:

> The BC OGC audit of the PNG IMP is in progress. A virtual interview between BC OGC integrity, engineering, and audit department staff and PNG representatives was held on November 26, 2020. A draft report of BC OGC findings was released for PNG review and comment on December 23, 2020 as part of an iterative process leading to the finalization of BC OGC findings, recommendations, and/or requested actions in 2021.

43.2 Please provide a copy of the draft report of BC OGC findings released to PNG on December 23, 2020.

Response:

PNG has received the final version of the BC OGC's IMP audit findings report, including a listing of required Corrective Action Plans derived to ensure ongoing continuous improvement of PNG's IMP. Given the sensitivity of detailed risk and integrity related materials, PNG has submitted the requested report on a confidential basis, along with its responses to BCUC Confidential IR No. 2.

For reference, PNG has also provided a copy of the Corrective Action Plans developed and submitted by PNG to the BC OGC for review and approval on February 17, 2021, along with its responses to BCUC Confidential IR No. 2.

PNG notes that the BC OGC audit findings and associated requested corrective actions are in alignment with those presented by PNG in response to BCUC IR 3.2.1.

43.3 Please clarify when PNG expects BC OGC's audit of PNG's Integrated Management Plan (IMP) will be completed.

Response:

Please see the response to Question 43.2.

In response to BCUC IR 103.1 in the PNG West 2020-2021 RRA proceeding, PNG attached an email it had received from the BC OGC in which the BC OGC requests specific aged pipeline integrity records. The BC OGC concludes its email to PNG with the following statement: "The Commission [the BC OGC] will review the information received. After the review, the Commission may contact the permit holders [PNG] for any follow up."

43.4 Please clarify whether the BC OGC has provided PNG with any further information regarding the anticipated outcomes of its aged pipeline review.

Response:

Please see the response to Question 43.2.

43.4.1 Please discuss the likelihood that the BC OGC will mandate remediation work on segments of the Salvus to Galloway pipeline not currently included within the proposed scope of this Certificate of Public Convenience and Necessity (CPCN) for the Salvus to Galloway Gas Line Upgrade Project (Project).

Response:

PNG is not able to speculate on this matter at this time, as such direction will be subject to the BC OGC findings from their aged pipeline asset review process which is expected to be completed no earlier than late in the third quarter of 2021.

That said, as emphasized by PNG response to BCUC IR 3.1.1, PNG believes the scope of work proposed within the Application will address the highest priority integrity repairs required to ensure fitness for service of the Salvus to Galloway segment while maintaining prudency and reducing hazard and risk, and notes that the scope of the Application encompasses the entirety of the Salvus to Galloway segment.

43.4.1.1 Should the BC OGC mandate remediation work on segments of the Salvus to Galloway pipeline not currently included within the proposed scope of this Project? Please discuss, with rationale, whether PNG would seek to include the mandated work as part of the Project for review in this Application.

Response:

Scope growth on the Salvus to Galloway segment in terms of additional, discrete, remediation activities identified by the BC OGC aged asset review but not clearly identified within the Application would be considered candidacy for draw down on project contingency and/or management reserve, depending on the nature and extent of the identified remediation.

Anything of significant enough additional scope (complex in nature) that could not be accommodated as an in-flight change to the existing project scope would likely require considerable additional scoping, engineering study, and design before getting to a place where overall cost, schedule, and scope could be well understood. As a result, it would be unlikely for PNG to consider any such hypothetical scenario as an addition to the Project presently under review in this Application.

In the event that significant remediation is identified by the BC OGC that is not part of the project scope and could not be undertaken within the project contingency and/or management reserve, PNG would evaluate its regulatory options which may include seeking an amendment to the approved CPCN through some manner of expedited proceeding, filing an application for a new CPCN seeking approval of the work, or seeking approval for the work in a future revenue requirements application. Prior to making a decision on this matter, PNG would inform the BCUC and consult with BCUC Staff as to the most appropriate course of action.

43.4.1.2 If yes, please discuss how such Project changes could be included in the current review of the Application.

Response:

Please see the response to Question 43.4.1.1.

43.4.1.3 If no, please explain whether the mandated remediation work would require or trigger a new CPCN or other review and approval by the BCUC.

Response:

Please see the response to Question 43.4.1.1.

B. PROJECT DESCRIPTION

44.0 Reference: PROJECT DESCRIPTION
Exhibit B-1 (Application), Section 6.4.1, p. 88; PNG West 2020-2021 Revenue Requirements Application (RRA) proceeding, Exhibit B-7, BCUC IR 117.2
Project Schedule

On page 88 of the Application, PNG states:

> Specific project activities and their respective milestone dates are summarized in Table 6-6. The anticipated project schedule is based on receiving BCUC project approval by June 30, 2021 and an assumed construction start in the third quarter of 2021. Typically, for the given project location, in-field construction activities correspond to aquatic and terrestrial habitat related least risk timing windows which generally occur in summer months. Construction is planned for each of 2021, 2022, and 2023.

Table 6-6 from page 88 of the Application is reproduced below:

Table 6-6: Project Schedule

Activity	Timeline		
Project Planning			
FEED	Completed		
Indigenous and Stakeholder Consultation	Ongoing		
CPCN Preparation	January 2020 – October 2020		
CPCN Regulatory Review	October 2020 – June 2021		
Project Execution	**2021 Construction**	**2022 Construction**	**2023 Construction**
Engineering Detailed Design	September 2020 - January 2021	September 2021 – December 2021	September 2022 – December 2022
Contractor Selection and Award	October 2020 - January 2021	October 2021 - January 2022[1]	October 2022 - January 2023[1]
Materials Tendering / Orders Placed	January 2021 – August 2021	January 2022 – March 2022	January 2023 – March 2023
Submit OGC Application	December 2020	August 2021	August 2022
OGC Pipeline Approval	March 2021	January 2022	January 2023
Award Contractor (or Extend)	April 2021	April 2022[1]	April 2023[1]
Materials Delivery	March 2021	March 2022	March 2023
Construction Start	July 2021	May 2022	May 2023
In Service	November 2021	November 2022	November 2023
Restoration	September – November 2021	September – November 2022	September – November 2023

[1] If necessary.

In response to BCUC's IR 117.2 in the PNG West 2020-2021 RRA proceeding, PNG stated:

> The costs incurred and previously approved for 2018 and 2019 and the forecast costs for Test Years 2020 and 2021 pertain primarily to the design, planning and prioritization, permitting, and detailed design and construction package development of the project, as well completion of critical access improvements and high priority integrity repairs in a readily accessible portion of pipeline…

The costs for Test Years 2020 and 2021 are required to get the project to the point of a CPCN application and approval of that application, and to progress the critical and high-priority pipeline risk mitigation and procurement activities in order to avoid the loss of both the 2020 and 2021 construction windows for a pipeline with known appreciable integrity risk and currently subject to the focus of the BCOGC under their pipeline segment specific risk assessment and aged pipeline condition assessment program intended to validate fitness for service…

Based on PNG's evaluation, the costs incurred in 2018, 2019, and forecast to be spent in 2020 and 2021 are considered discrete projects, and include the completion of the feasibility/planning documents, construction of staging sites, and remediation to specific sections. As these are discrete projects and the physical construction is planned to be completed in 2020 and 2021, and therefore completed and available for use, PNG will be capitalizing these costs to plant in service.

44.1 Please differentiate between the scope of remediation work on the Salvus to Galloway pipeline to be completed in 2021 as part of this CPCN Application and the scope of remediation work to be completed in 2021 on the same pipeline already approved as part of PNG's 2020-2021 RRA.

Response:

The scope of work being completed in 2021 as approved in PNG's 2020-2021 Revenue Requirements Application is narrow in nature as compared to the much larger scope intended in 2021 following the approval of this Application.

The following table summarizes the extent of scope for each and their respective budget/costs anticipated to be incurred in 2021.

Approval Authority	Scope of Remediation Activities	Cost Estimate
2020-2021 RRA (Jan 1 to Jun 30 2021)	Segment 4 – FEED Study completion Segment 4 – detailed design, procurement, permitting Segment 4 – clearing, access and bridge construction[1] Segment 3 – engineering/procurement Segment 3 – dig site repairs[2]	$2,218,500
CPCN Application (Jul 1 to Dec 31 2021)	Segment 4 – construction/remediation[3] Segment 1 – planning for 2022 works	$24,194,000

[1] Required to be completed prior to July 1, 2021 to meet required environmental least risk timing windows and bird nesting season.
[2] 2021 Segment 3 works associated with MP 344.8 to MP 349.1
[3] 2021 Segment 4 works associated with MP 349 to MP 361

44.1.1 Please explain the need for CPCN approval by June 2021, if PNG has already received approval for remediation work on the Salvus to Galloway pipeline for 2021 as part of the PNG West 2020-2021 RRA approval.

Response:

As presented in response to Question 44.1, the scope of work that is proposed to be completed within the limits of the approved 2020-2021 RRA budget is minimal in comparison to the work required to be completed in 2021 as outlined in the Application. PNG notes that at the time of the 2020-2021 RRA proceeding the final scope of the proposed Salvus to Galloway Project was not yet known. Study work required to identify and define the final scope was underway and only those activities known to be required regardless of the Project's final scope were intended for the funding approved in the 2020-2021 RRA.

Based on the work required to be completed in the 2021 construction window of April 2021 to October 2021, a June 2021 Application approval dates is aligned with the necessary start of key field construction activities, including access bridge construction scheduled around the salmon species Least Risk Timing Window (LRTW) of July 1- July 30 for at least two required crossings, the Kloiya River and Fortune Creek. Due to Department of Fisheries and Oceans (DFO) constraints related to instream works at these crossings, necessary work can only occur in the LRTW.

Approval of this Application later than mid-June 2021 has the potential to compromise the ability to complete this work, which will have a compounding affect on other project-related activities given the required linear work methodology along the right of way, with passage of these streams being necessary in order to progress work further up-chain on the pipeline. This would result in a significant shift of scope and cost from 2021 to 2022, which will be very difficult to recover from in terms of overall project execution.

Furthermore, given the overall magnitude of construction work required to be completed in each of the Project's calendar years to meet the Project's objectives, and recognizing the weather and sensitive habitat related limitations in some of the work areas, optimizing the availability of the narrow construction windows will be required for project success. Consequently, the Application approval date does have the potential to impact broader works considered necessary for 2021.

C. PROJECT NEED AND JUSTIFICATION

45.0 Reference: PROJECT NEED AND JUSTIFICATION
Exhibit B-2, BCUC IR 9.5
Elevated Integrity Risk Management

In response to BCUC IR 9.5, PNG stated:

> As part of the works contemplated within this Application, PNG plans to address pressure-dependent known pipeline anomalies and defects required to safely operate at the pressures necessary to serve RECAP customers and/or other future load growth. At the proposed future higher operating pressures there will be reduced tolerances on threats like corrosion depth, mechanical damage related metal loss, and dent depth and cycling, resulting in the need for increased frequency of inspection and subsequent repair as required to sustain safe operation and compliance. With the reduced safety margins that come with increased operating pressure (resulting in increased hoop stress as a percentage of minimum yield strength, for example), further hazard identification and risk management related to operating parameters, external threats, and overall pipeline condition will be required into the future. Relatedly, but independent of the above, this degree of ongoing and elevated integrity risk management is expected to be required via the technical and safety governance of the BC OGC and its direct association with the continuous improvement aspects of CSA Z662.

45.1 Please compare PNG's historical and forecasted pipeline inspection schedule and associated risk management activities.

Response:

The following table compares, and contrasts PNG's historic and forecasted pipeline inspection, monitoring, and maintenance schedules and associated risk management activities related to time dependent threats such as corrosion and dent and external threats such as force related to geohazards for the Salvus to Galloway pipeline segment.

IMM and Risk Management Activities	Description	Frequency		Forecast Future Cost Differential	Comments
		Historic	Forecasted		
Remote Supervisory Control and Data Acquisition	Remote control room monitoring 24/7 of pipeline system process condition including pressure, flow, and process variable rate of change.	Continuous	Continuous	N/A	No change. 24/7 remote monitoring and control sustained.

IMM and Risk Management Activities	Description	Frequency		Forecast Future Cost Differential	Comments
		Historic	Forecasted		
In-Line Inspection (ILI)	Smart tool internal inspection to identify internal and external corrosion, linear anomalies, dents and deformation, mechanical damage and displacement from external force.	10 Years	5 Years	$750,000 / 5 Years	• ILI historically inspected the Salvus to Galloway segment on a 10 year or greater frequency. • Based on results of the 2018 inspection and adjusting to a risk based inspection frequency for the specific pipeline, including the need for improving certainty around corrosion growth and affects of geotechnical activity, for example, PNG is forecasted to move to a 5 year inspection frequency for minimum 2 inspection cycles. • This will be adjusted / informed by inspection and monitoring results, outputs of PNG's segment-based risk assessment models, and direct assessment findings.
Over-the-Line Inspection (OTLI)	Inclusive of external coating condition survey via Direct Current Voltage Gradient/ Alternating Current Voltage Gradient (DCVG/ACVG) and cathodic protection close interval survey.	None	5 Years	$150,000 / 5 Years	• PNG has not historically conducted DCVG/ACVG or CIS on transmission system segments subject to in-line inspection. • PNG will begin incorporation of OTLI on a go-forward basis to better align with industry standard best practice. • This will be done on a risk-adjusted basis for the purposes of frequency determination and priority. • Frequency is proposed to match ILI frequency.

IMM and Risk Management Activities	Description	Frequency		Forecast Future Cost Differential	Comments
		Historic	Forecasted		
Corrosion Prevention System Inspection and Monitoring	End point and mid point testing and monitoring of impressed current cathodic protection system.	Monthly	Monthly	N/A	• Frequency and activity detail sustained. • PNG will increase test lead locations and remote monitoring capabilities during Salvus to Galloway project activities. Remote monitoring is conducted daily.
Direct Assessment (DA)	Investigative digs associated with ILI and OTLI outputs.	>10 Years	5 Years	$5 million / 5 Years	• Historic frequency of direct assessments was variable, with periods greater than 10 years. • On a go forward basis direct assessments will be planned following ILI and OTLI and executed as required. • DA quantity will be driven by ILI and OTLI outputs and will be managed / reduced through detailed engineering assessment.
Aerial Patrol	Helicopter and fixed wing aircraft patrol	>2 Per Year	>2 Per Year	$20,000 / Year	• PNG standard practice requires a minimum of 2 aerial patrols annually. • This is supplemented as required based on special conditions such as extreme weather events, evidence of third party activity in proximity, and/or geotechnical and hydrotechincal risk. • PNG expects frequency of patrols to increase in direct association with ongoing development of comprehensive geohazard management plans. • Additionally PNG will incorporate aerial leak survey using methane

IMM and Risk Management Activities	Description	Frequency		Forecast Future Cost Differential	Comments
		Historic	Forecasted		
					detection instrument technologies and high resolution cameras where this was historically limited to ocular observation of ground staining or vegetation die-off.
Pipeline System Risk Review	Office-based risk review of the pipeline system, incorporating the elements of PNG Risk Management Program and the inputs of various subject matter experts and stakeholders.	Annual	Annual	N/A	• Taking the form of PNG's Annual Risk Review Meeting (ARRM), and resulting in an Annual Risk Mitigation Report, this activity frequency is forecasted to be sustained. • Steps and other inclusions will evolve to further align with CSA Z662 Annex B and the continuous improvement measures ongoing associated with PNG's documented Risk Management Program within its IMP. • Specific focal point improvement for the Salvus to Galloway segment will be associated with geohazards.
Engineering Assessment	Engineering assessment up to Level 3 fitness for service assessments.	Irregular	As Required	$50,000 / 5 Years	• Follow-on engineering assessments at frequencies warranted by identified appreciable change to the pipeline integrity condition.
Geohazard Assessment	Site specific geohazard assessments.	None	As Required	$100,000 / 3 Years	• Follow on geohazard assessments of newly identified or currently monitored existing geohazards. • Specifics to be formalized as part of BC OGC driven mandate

IMM and Risk Management Activities	Description	Frequency		Forecast Future Cost Differential	Comments
		Historic	Forecasted		
					related to comprehensive geohazard management.

PNG notes that as an outcome of the BC OGC's 2020 audit of the PNG IMP, specific risk management plans and program documents will be developed for stress corrosion cracking, geotechnical, and hydrotechnical hazards. These plans and program documents will be comprehensive in nature and will document how, and at what frequency, PNG will monitor, inspect, and mitigate hazard and risk associated with these identified threats.

45.2 Please elaborate on any cost increase for pipeline integrity management activities related to the proposed higher operating pressure.

Response:

Please refer to the cost differential values provided in response to Question 45.1. While these anticipated increases in cost for pipeline integrity management activities are not exclusively associated with the proposed higher operating pressure, the higher operating pressure will contribute to the need as previously described in response to BCUC IR 9.5 and presented in the preamble to this series of questions.

45.3 Please explain why PNG expects that the BC OGC will require this degree of ongoing and elevated integrity risk management.

Response:

As provided in PNG's response to BCUC IR 9.5, and other associated references and responses provided throughout the Application process, CSA Z662 specifies a need for continuous improvement around integrity management. This is enforced by the BC OGC through their regular audit of operator IMPs and through application of their associated compliance protocols. How this translates to the active and improved management of aging assets has been formalized in the BC OGCs rollout of their Aged Pipeline Asset Condition Assessment program under which the Salvus to Galloway segment is subject to review. Furthermore, specific IMP improvement requirements related to inspection, maintenance, and monitoring, geohazard management, and risk management have been identified through the OGCs 2020 audit of PNGs pipeline system IMP.

46.0 Reference: PROJECT NEED AND JUSTIFICATION
Exhibit B-2, BCUC IR 11.3
Residual Pipeline Integrity Risk

In response to BCUC IR 11.3, PNG stated:

> PNG has not specifically quantified the residual risk associated with each of the Upgrade Pipeline sub-options. Based on the scope contemplated for each of the sub-options relative to a complete pipeline replacement and relocation, it can be stated that there would be residual risk associated with each upgrade sub-option. Given that the highest priority corrosion and dents will be addressed and line lowering in high risk locations will be completed for each sub-option, PNG is of the believe [sic]that the best relative representation of residual risk between the four sub-options is based on what high risk geohazards will remain unaddressed.

46.1 Please explain why PNG has not quantified the residual risk associated with each of the Upgrade Pipeline sub-options.

Response:

PNG is of the belief that for the purposes of this Application, and in the context of required comparison of each of the Upgrade Pipeline sub-options relative to one another and relative to complete pipeline replacement and relocation in order to identify a preferred project alternative, that residual risk quantification was not warranted, or necessary in coming to the preferred alternative.

As described in response to BCUC IR 11.3, the respective scopes of each Upgrade Pipeline sub-option as they pertain to high-priority pipe defect repair and high-risk area line lowering to address pipeline exposure or exposure threat are generally similar with the exception of UA 1 that has a reduced scope. As such, PNG is of the belief that presentation of residual-risk quantification associated with high-risk geohazards provides the most appropriate quantified representation for the purposes of the Application.

This is represented in the work of BGC Engineering as residual Monetized Risk post mitigation and is provided graphically in Figure 5-2 of BGC's 2020 Geohazard Mitigation Plan report included as Appendix D to the Application. The table below provides the approximated residual geohazard related monetized risk for each Upgrade Pipeline sub-option. As demonstrated in the table, a move to UA 3 or UA 4 would decrease the residual monetized risk but it is not a cost-effective solution to do so. For example, moving from UA 2 to UA 3 increases the NPV by $54 million but the monetized residual risk only decreases by $15 million.

Additionally, as recommended in response to BCUC IR 11.3, Section 5.5 of the Application can be referred to for a significant listing of qualifying details associated to risk mitigation and residual risk for each of the sub-options, noting the details within Table 5-7 thru Table 5-11 of the Application.

Future additional work associated with pipeline risk and residual risk quantification for the Salvus to Galloway pipeline segment will be encompassed within the recently implemented segment-based risk model and ongoing refinements and improvements to PNG risk identification, assessment, and management practices as explored in PNG's response to BCUC IR 3.3 and associated sub-series responses.

Project Alternative	Risk Related Scope Variation	NPV of Project Alternative ($million)	Residual Monetized Risk of High / Very High Geohazards ($million)
UA 1	• No line lowering • No geohazard mitigations	84	38
UA 2	• Geohazard mitigation with CBR < 1.0 • High risk area line lowering	92	27
UA 3	• Geohazard mitigation with CBR < 2.0 • Additional line lowering	146	12
UA 4	• Mitigation of all remaining high / very high geohazards • All remaining line lowering	233	0

46.2 Please discuss whether PNG has defined its level of acceptable risk for the pipeline. If not, why not.

Response:

PNG has defined its level of acceptable risk for the pipeline. As emphasized throughout the Application, given the challenges and inherent risks associated with original construction practices, access complexities associated with the terrain, and the high cost of proactive risk reduction, balanced against the extreme remoteness of the pipeline alignment and its separation from the public and other infrastructure, PNG has employed a risk-adjusted approach to its management of the pipeline in order to maintain safe and reliable operation. All variables considered, through the application of the 'ALARP' approach to risk management, PNG accepts a risk level of this pipeline that is moderately greater than its typical tolerance line in its established risk matrix.

Through application of the PNG risk matrix (include in confidential Appendix M to the Application), the following tables provide summarized representation of the pipeline's accepted risk line and respective risk category scores.

Threat / Hazard Likelihood	Consequence of Incident				
	1	2	3	4	5
5					
4	HS	EN, RG	RP, OI	FR	
3					
2					
1					

Consequence Category	Risk Table Symbol
Health & Safety	HS
Environmental	EN
Regulatory	RG
Reputation	RP
Operational Impact	OI
Financial Risk	FR

46.2.1 Please state PNG's level of acceptable risk for the pipeline at current operating conditions and at the proposed higher operating pressure, if different.

Response:

Please see the response to Question 46.2. PNG's level of acceptable risk is not operating pressure dependent.

46.2.2 Please confirm, or otherwise explain, that the residual risk associated with each of the Upgrade Pipeline sub-options is within PNG's level of acceptable risk.

Response:

The residual risk associated with Upgrade Pipeline sub-options UA 2, UA 3, and UA 4 are within PNG's level of acceptable risk, recognizing that only levels of residual geohazard risk set them apart materially and that it is accepted industry practice to actively monitor residual geohazard risk in remote areas of low safety likelihood and/or consequence particularly for operators with a prevalence of geohazards in tight and challenging terrain with unusually high costs of mitigation. This was discussed in PNG response to BCUC Confidential IR 7.3.1.

Due to the absence of any high-risk geohazard mitigation or high-risk area line lowering associated with UA 1, PNG would not be accepting of the residual risk associated with that sub-option.

46.2.3 Please explain PNG's methodology for determining whether the residual risk with each Upgrade Pipeline sub-option is within PNG's level of acceptable risk.

Response:

PNG leverages its risk matrix for the purposes of this determination. In the case of this very remote pipeline, with a history of safe and reliable service, some of the higher risk categories such as financial risk are offset equally or greater by the low risk to health, safety, and the environment. Please refer to the responses to the Question 46 series of information request presented above for further discussion regarding residual risk and PNG's acceptance thereof.

47.0 Reference: PROJECT DESCRIPTION
Exhibit B-2, BCUC IR 23.3, 23.4; Exhibit B-1, Section 6.8.1, p. 97
Acceptable Level of Pipeline Integrity Risk

In response to BCUC IR 23.3, PNG stated:

> If extreme challenges related to achieving the design specified minimum depth of cover were encountered that prevented going deeper via excavation, blasting, or rock hammering, PNG would look to employ other mitigation measures such as rock jacketing, other forms of external pipe protection, and/or adding to surface grade elevation in order to achieve risk reduction in line with the 'As Low As Reasonably Practicable' approach. When the cost and effort intensiveness increases to the point where it is met with unbalanced incremental improvement in risk reduction, PNG may elect to move closer to its defined tolerance line within its risk matrix, effectively accepting higher risk relative to the lowest risk possibly achieved in the presence of infinite time, money, and resources.

In response to BCUC IR 23.4, PNG stated:

> PNG's risk assessment and management processes are documented within Section 4 of its current Integrity Management Program Manual. This is written and practiced in accordance with CSA Z662-19 Annex B Guidelines for Risk Assessment of Pipeline Systems, including the principles of risk evaluation and consideration and effective decision making related to risk reduction measures. Provided residual risk is not considered significant, or if significant, is being managed appropriately given potential consequences, PNG may determine through application of the 'As Low As Reasonably Practicable' [ALARP] approach to accept and manage risk above the lowest risk possibly achieved in the presence of infinite time, money, and resources.

On page 97 of the Application, PNG states: "For reference, PNG's risk matrix has been incorporated into the Risk Registry that is appended as confidential Appendix M."

47.1 Please provide a copy of Section 4 of PNG's Integrity Management Program Manual, confidentially if necessary.

Response:

The requested documentation has been appended as a PDF file named: Attachment BCUC 47.1 - PNG IMP - Section 4 Risk.

47.1.1 With reference to CSA Z662-19 Annex B and PNG's Integrity Management Program Manual, please explain how the application of PNG's risk assessment and management processes establish the residual risk to a pipeline as not significant.

Response:

Based on PNG's risk matrix and the other contributing and applicable content within PNG's risk management program(s), a risk found to present either a 'low loss' or 'no loss' condition based on the combination of either pre- or post-mitigation (control) hazard and consequence may synonymously be considered 'not significant' as phrased in the context of response to BCUC IR 23.4 and provided in the associated preamble above.

This pre- or post-risk mitigation state would indicate that controls are adequate, associated procedures for monitoring of the risk condition were in place, and that no further mitigations or controls would be warranted. Conversely, if found to have 'significant' residual risk, but within PNG's tolerance for the specific hazard and consequence case, and managed within the intents of the 'As Low as Reasonably Practicable (ALARP)' approach, PNG may elect to manage such risk through active monitoring and inspection until a future mitigation is considered. This is in line with Section 4 Risk Management of the PNG IMP, which itself is aligned with the requirements of CSA Z662 Annex B.5.3.1 on Risk Significance where it is stated that the assessment of risk significance involves consideration of the importance of the estimated level of risk to those who can be affected by the outcome of the hazardous event and that the significance of the estimated risk depends on the context within which the risk assessment is being undertaken. CSA Z662 Annex B.5.3.1.2 speaks to the accepted consideration of the costs associated with any incremental reduction in the estimated risk level, contributing to the overall concept of adjusted risk tolerances on a situation specific basis and the acceptability of the use of levels of reasonableness and practicality.

47.2 Please explain the processes that PNG would undertake if pipeline repair circumstances encountered during execution of this Project required the acceptance of higher risk.

Response:

Any project-related requirement for proposed adjustment to PNG's already accepted level of risk for the pipeline segment (as presented in the responses to Questions 46.2 and 46.2.3) would require review and authorization at the project steering committee level. This is inclusive of PNG Senior Director and Vice President level authorizations, informed by the inputs of PNG's EHS, Asset Integrity, Operations, Engineering, Finance, and Regulatory leadership teams. Any resultant acceptance of higher risk would be documented in a Project Decision Record as part of the Projects Change Management execution plan.

47.2.1 Please discuss how PNG defines its "tolerance line within its risk matrix." Wherever possible in a non-confidential manner, please provide any quantitative risk thresholds which define the tolerance line.

Response:

PNG's tolerance line within its risk matrix is clearly defined in its default state. This is achieved through the quantification of the contributing hazards and consequences for each documented consequence category. This default tolerance line is indicative of PNG being balanced in its acceptance and aversion to risk in order to maintain an appropriate and prudent balance between risk reduction and cost impact while continuing to maintain primary focus on safe and reliable service. As explained within the Application and throughout numerous related information request responses, this risk tolerance line may be adjusted on a case-specific basis through consideration of the potential outcomes of a hazardous event. PNG's risk tolerance associated with the pipeline segment applicable to the Application has been described in response to Questions 46.2 and 46.2.3.

PNG's risk matrix (confidential Appendix M) and risk management section of its IMP (appended in response to Question 47.1) provide greater detail on processes and quantifications.

47.3 Please discuss whether any of the proposed scope of work for this Project can be deferred through application of the ALARP approach, in such cases where "residual risk is not considered significant, or if significant, is being managed appropriately given potential consequences."

Response:

PNG does not believe any of the proposed scope of work for the Project can be deferred given that the proposed scope is limited to only the highest-priority corrosion-related metal loss features impacting operating pressure, dents defined as defects by CSA Z662, and one geohazard band of very-high risk that is cost favorable to mitigate now versus conducting future emergent pipeline repairs in its vicinity. It is through the application of the ALARP approach that PNG believes it has developed and proposed the most reasonable and prudent project solution, electing to continue inspection and monitoring of lower-risk pipe anomalies and geohazards and deferring mitigation and repair in the short term.

PNG notes that as part of the proposed Project, level 3 engineering assessment with finite element analysis will be performed on dents identified as defects under CSA Z662 in order to determine if any associated intended repairs can be avoided.

47.3.1 If so, please discuss changes to Project cost and schedule that would result from such a deferral.

Response:

Please see the response to Question 47.3.

47.3.2 If so, please discuss why PNG has not chosen to defer this work.

Response:

Please see the response to Question 47.3.

47.4 Please discuss whether any of the proposed scope of work for this Project could be deferred by implementing pipeline monitoring. If not, why not.

Response:

Please see the response to Question 47.3. PNG will continue with its current pipeline monitoring and inspection regime, increase the frequency of ILI (including inertial movement for bend strain analysis) from its historic frequency of 10 years to 5 years, and increase the frequency of geohazard-specific inspection and monitoring. PNG will also be increasing the number of corrosion prevention related test lead posts and remote monitoring units in order increase monitoring related to the existing impressed current cathodic protection system.

47.4.1 If yes, please discuss whether PNG considered implementing pipeline monitoring and why it was not pursued.

Response:

Please see the response to Question 47.4.

48.0 Reference: PROJECT NEED AND JUSTIFICATION
Exhibit B-2, BCUC IR 8.1; 7.3
Location and Nature of Pipeline Failure

In response to BCUC IR 8.1, PNG explained:

> The ability and duration to which the pipeline can sustain gas supply to customers in the event of an incident resulting in a failure is largely dependent on the load on the system at the time of the failure, the location of the failure, and the nature of the failure (leak or rupture).

In response to BCUC IR 7.3, PNG stated: "In order to serve the RECAP customers located at Prince Rupert and Port Edward, additional compression will be required at Salvus in order to maintain minimum required end-point pressure at the Prince Rupert terminus of the Western Transmission Gas Line."

48.1 Please discuss whether the future compressor at Salvus to serve Reactivation Capacity Allocation Process (RECAP) customers could affect the location of a potential pipeline failure.

Response:

The pipeline downstream of the proposed compressor station location was originally designed and tested to operate at the pressures proposed in order to sustain RECAP customers. Repairs proposed to be enacted as part of the Project within this Application will be performed to ensure fitness for service at the future proposed operating pressure. The proposed compressor station will be on a dry natural gas system with minimal pressure cycling imposed to the pipeline owing to the compressibility characteristics of gas, limiting the detrimental pressure cycling impacts found on liquids pipelines.

With the future Salvus compressor station, the pipeline downstream of the compressor will experience higher temperatures. A cooler will be installed at the compressor station to reduce the gas product temperature to acceptable levels. Nevertheless, the pipeline may be subject to higher temperatures at which the soil surrounding the pipe can be dried out causing higher soil electrical resistance and negative impacts on the established cathodic protection systems. This could facilitate initiation of stress corrosion cracking (SCC) in the pipeline. However, this effect has only been previously reported within the industry for pipeline tape coatings, not for the yellow jacket and Stopaq coating systems employed during original construction and subsequent repair. Higher operating temperatures can cause the temperature differential between the soil restraint temperature and operating temperature to increase, with possible impact on the pipeline stress condition. The stress impact will be more pronounced for the axial and combined stresses at the pipeline bends. A detailed stress analysis will be completed to support the selection of the maximum operating temperatures and to identify the high-stress locations along the pipeline for lowering, short-span realignment, or additional restraint to be carried as part of localized repairs within the Project and/or for ongoing monitoring post-Project and the implementation of any necessary future mitigations.

As a result, PNG does not believe that the future compressor station at Salvus will be a contributing factor to the location of a potential future pipeline failure.

48.1.1 If yes, please explain any potential impacts to the ability and duration of the pipeline to sustain gas supply to customers and PNG's ability to access and repair the pipeline.

Response:

Please see the response to Question 48.1.

48.2 Please discuss whether the proposed future higher operating pressure could affect the mode of a potential pipeline failure (leak or rupture).

Response:

The failure of a pipeline defect results in either a leak or a rupture. If the stress is low or the defect is short, then the defect will fail as a leak. If the stress is high or the defect is long, then the defect will fail as a rupture. A rupture may result in a propagating fracture. The failure of a partially through-wall defect results in a through-wall defect. If the resulting through-wall defect is unstable and therefore fails (i.e., the length of the through-wall defect increases), then the failure of the part-wall defect is described as a rupture. If the resulting through-wall defect is stable, then the failure of the partially through-wall defect is described as a leak.

A partially through-wall defect fails as a rupture when its length is equal to or exceed a specific defect length and fails as a leak when its length is shorter than the specific length. This critical length is defined as the leak-rupture boundary of the defect. The leak-rupture boundary depends on the pipe geometry, the strength and toughness of the pipe steel, and the applied load. In general, the leak-rupture critical length decreases as the hoop stress, thereby operating pressure, increases. This indicates that the pipeline is more susceptible to rupture failure with higher operating pressure.

48.2.1 If yes, please describe any studies to assess the potential failure mode (leak or rupture) of the pipeline at current operating pressure and at the proposed future higher operating pressure and provide the results of this assessments.

Response:

The PNG standard practice to assess in-line inspection (ILI) features is to conduct the engineering assessments and the associated prioritizations based on the design maximum operating pressure (MOP), which is 9,335 kPa (1,354 psi) for the NPS 8 pipeline, regardless of the maximum operating pressure at the time of inspection or assessment. Both leak and rupture failure modes are considered in the prioritization and mitigation decision-making process of the critical ILI features to ensure the overall integrity of the pipeline. The same methodology is utilized in the ongoing BC OGC Aged Pipeline Asset Engineering Assessment of the NPS 8 mainline.

D. PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACTS

49.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACTS
Exhibit B-1, Section 7.3, pp. 107–108; Exhibit B-2, BCUC IR 32.5
Rate Impacts

On page 107 of the Application, PNG provides the following table showing the rate impacts of the project including all costs and revenues related to the 65 MMSCFD RECAP volumes:

Table 7-7: Rate Impact of the Project plus RECAP Volumes of 65 MMSCFD

	2021E	2022E	2023E	2024E	2025E	2026E	2027E
RECAP Revenue	-	852,506	12,343,726	24,370,404	30,056,127	29,838,886	29,939,060
Cost of Service							
2021 Revenue Requirements Application	42,248,182	42,248,182	42,248,182	42,248,182	42,248,182	42,248,182	42,248,182
Salvus to Galloway	(158,783)	1,643,914	5,287,684	6,623,484	6,661,147	6,685,911	6,698,807
RECAP	-	33,766	1,084,999	946,820	4,664,359	4,056,342	4,312,079
Total	42,089,399	43,925,863	48,620,865	49,818,486	53,573,688	52,990,435	53,259,068
Revenue Deficiency/(Sufficiency)							
Salvus to Galloway Project	(158,783)	1,643,914	5,287,684	6,623,484	6,661,147	6,685,911	6,698,807
RECAP Margin	-	(818,740)	(11,258,727)	(23,423,584)	(25,391,768)	(25,782,544)	(25,626,981)
Total	(158,783)	825,174	(5,971,043)	(16,800,100)	(18,730,621)	(19,096,633)	(18,928,174)
CAGR Relative to 2021 Rates		2.0%	-7.3%	-15.5%	-13.6%	-11.3%	-9.4%
Year over Year Rate Increase		**2.0%**	**-15.8%**	**-29.9%**	**-7.6%**	**-1.6%**	**0.7%**
Residential delivery rates ($/GJ)	12.68	12.93	10.89	7.64	7.06	6.95	7.00

On page 108 of the Application, PNG provides the following table showing the rate impacts of the project including costs and revenues "associated with the smaller of the two RECAP proponents' load of 30 MMSCFD":[1]

Table 7-8: Rate Impact of the Project plus RECAP Volumes of 30 MMSCFD

	2021E	2022E	2023E	2024E	2025E	2026E	2027E
RECAP Revenue	-	-	2,113,652	10,568,258	12,681,910	12,983,074	13,167,848
Cost of Service							
2021 Revenue Requirements Application	42,248,182	42,355,682	42,031,611	42,358,967	42,248,182	42,248,182	42,248,182
Salvus to Galloway	(158,783)	1,643,914	5,287,684	6,623,484	6,661,147	6,685,911	6,698,807
RECAP	-	-	(181,957)	664,826	888,763	905,331	929,570
Total	42,089,399	43,999,596	47,137,338	49,647,276	49,798,092	49,839,424	49,876,560
Revenue Deficiency/(Sufficiency)							
Salvus to Galloway Project	(158,783)	1,643,914	5,287,684	6,623,484	6,661,147	6,685,911	6,698,807
RECAP Margin	-	-	(2,295,609)	(9,903,433)	(11,793,147)	(12,077,743)	(12,238,277)
Total	(158,783)	1,643,914	2,992,075	(3,279,949)	(5,132,000)	(5,391,832)	(5,539,470)
CAGR Relative to 2021 Rates		3.9%	3.5%	-2.7%	-3.2%	-2.7%	-2.3%
Year over Year Rate Increase		**3.9%**	**3.1%**	**-13.9%**	**-4.8%**	**-0.7%**	**-0.4%**
Residential delivery rates ($/GJ)	12.68	13.18	13.58	11.70	11.14	11.06	11.02

[1] Exhibit B-1, Section 7.3, p. 106.

In response to BCUC IR 32.5, PNG stated:

> PNG notes that it expects to file a CPCN for the RECAP Project early in 2021 which will detail the cost of service components by cost category. PNG further notes that the capital costs and timing of the costs are currently being refined and the analysis will be different from that provided in the instant Application. As such, PNG believes that it not meaningful to provide a breakdown the RECAP cost of service each year by cost category at this time as the RECAP project estimates are not yet final. [*Emphasis Added*]

49.1 Please explain whether PNG expects the rate impact analysis in Table 7-7 and Table 7-8 to change significantly as a result of the final RECAP cost of service estimates.

Response:

PNG notes that while it has significantly advanced its work on the scope, engineering and cost components of the reactivation and recommissioning (RECAP) project, the project cost estimates are not yet finalized. However, at present PNG does expect the RECAP cost of service estimates to be higher than those shown in Table 7-7 and Table 7-8 of the Application, and consequently the rate impact analysis will change.

49.1.1 If yes, please provide details on the expected impact the refinements will have on the rate impact analysis in Table 7-7 and Table 7-8 of the Application.

Response:

Based on PNG's current expectations, the RECAP cost of service estimate will be higher and will reduce the revenue sufficiency to result in a compounded annual growth rate (CAGR) of approximately -6% by 2027 versus a CAGR of -9.4% as shown in Table 7-7 as reproduced in the preamble. PNG notes that the RECAP project, in combination with the Salvus to Galloway Project, is expected to generate a revenue sufficiency increase of approximately 35% relative to PNG's 2021 cost of service over the 19-year period when the RECAP customers are operating at the contracted demand as per the RECAP Transportation Service Agreements (TSAs). In the absence of any other cost of service adjustments or changes in revenues, PNG's most recent analysis indicates that with both the Project and the realization of 65 MMSCFD in RECAP volumes, residential delivery rates would decline by approximately a cumulative 34% from 2021 and 2025 versus 44% indicated in the instant Application.

PNG notes that its future revenue requirement applications will include rate impact mitigation proposals that reflect PNG's cost of service and revenues at the time those applications are filed and will not reflect the reductions in rates as illustrated in Table 7-7. PNG further notes that other factors will have an impact on customer rates in the near future, including the full amortization of the LNG Option Fee deferral account, an increase in provision from the continued phase-in of negative salvage, the expiry of the LDS#2 contract and the amortization of deferred Shared Corporate Services Costs.

Under the 30 MMSCFD scenario whereby only the smaller of the two proponent's load was assumed to come into service under RECAP, the revised cost of service estimates will result in a CAGR of approximately -0.4% by 2027 versus a CAGR of -2.3% as shown in Table 7-8 reproduced in the preamble above. Assuming a 30 MMSCFD increase in demand, the RECAP project, in combination with the Salvus to Galloway Project, is expected to generate a revenue sufficiency increase of approximately 5% relative to PNG's 2021 cost of service over the 19-year period when the RECAP customers are operating at the contracted demand as per the TSAs. In the absence of any other cost of service adjustments or changes in revenues, PNG's most recent analysis indicates that with both the Project and the realization of 30 MMSCFD in RECAP volumes, residential delivery rates will decline by approximately a cumulative 4% from 2021 and 2025 versus 12% indicated in the instant Application.

Once again, PNG notes that its future revenue requirement applications will include rate impact mitigation proposals that reflect PNG's cost of service and revenues at the time those applications are filed and will not reflect the reductions in rates illustrated in Table 7-8. PNG also notes that other factors will have an impact on customer rates in the near future, including the full amortization of the LNG Option Fee deferral account, an increase in provision from the continued phase-in of negative salvage, the expiry of the LDS#2 contract and the amortization of deferred Shared Corporate Services Costs.

49.2 Please explain how the RECAP cost of service estimates provided in Table 7-7 and Table 7-8 were developed.

Response:

The RECAP cost of service estimates provided in Table 7-7 and Table 7-8 were developed through a detailed financial model that will be included as an appendix to PNG's forthcoming CPCN application for reactivation and recommissioning associated with new industrial customer demand coming from the RECAP.

Key elements of the financial modeling for both the 65 MMSCFD and the 30 MMSCFD scenarios include:

- Underlying capital and operating cost estimates were prepared at the BCUC account level along with estimates spending profiles and timing of in-service for the specific assets. However, the capital cost and maintenance inputs to Tables 7-7 and 7-8 were high level and preliminary in nature as further engineering and scoping were underway to advance the estimates from a Pre-FEED scoping and accuracy level to the more detailed Class 3 project estimate that will support the forthcoming reactivation and recommissioning CPCN application.

- Depreciation, salvage value and capital cost allowances were modeled based on identified capital asset classifications.

- Cost of capital and debt were modeled based on PNG's current regulated capital structure and an estimate of incremental debt costs calculated using indicative debt rates provided by PNG's parent company, TriSummit Utilities.

- The overall cost of service for each year was constructed using estimates for depreciation, tax on depreciation, amortization of net salvage, tax on amortization of net salvage, interest, return on equity, tax on the return on equity, capital cost allowance tax reduction, property taxes and operating costs.