bcuc
British Columbia
Utilities Commission

Patrick Wruck
Commission Secretary

Commission.Secretary@bcuc.com
bcuc.com

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

July 7, 2021

Sent via email/eFile

PNG CPCN WESTERN TRANSMISSION REACTIVATION AND DEFERRAL ACCOUNT INCREASE EXHIBIT A-14

Mr. Verlon G. Otto
Director, Regulatory Affairs
Pacific Northern Gas Ltd.
750 – 888 Dunsmuir Street
Vancouver, BC V6C 3K4
votto@png.ca

Re: Pacific Northern Gas Ltd. – Certificate of Public Convenience and Necessity for the Western Transmission Gas System Reactivation and Recommissioning Project Application and Deferral Account Increase Application – Project No. 1599200 – Information Request No. 3

Dear Mr. Otto:

Further to your March 5, 2021 Application for a Certificate of Public Convenience and Necessity for the Western Transmission Gas System Reactivation and Recommissioning Project, enclosed please find British Columbia Utilities Commission Information Request No. 3. In accordance with the regulatory timetable for this proceeding, please file your responses on or before Monday, July 26, 2021.

Sincerely,

Original signed by:

Patrick Wruck
Commission Secretary

PS/dg
Enclosure

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

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TF: 1.800.663.1385
F: 604.660.1102

Pacific Northern Gas Ltd.
Application for a Certificate of Public Convenience and Necessity for the Western Transmission Gas System Reactivation and Recommissioning Project

INFORMATION REQUEST NO. 3 TO PACIFIC NORTHERN GAS LTD.

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A. PROJECT NEED

48.0 Reference: PROJECT NEED
Exhibit B-7, BCUC IR 2.4, 2.4.1
Pipeline Capacity

In response to British Columbia Utilities Commission (BCUC) Information Request (IR) 2.4, Pacific Northern Gas Ltd. (PNG) provided the following table:

Capacity in MMSCFD	Total pipeline transmission capacity		Contracted through the RECAP process (3)	Demand from existing customers (Peak) (2)		Available Capacity
Delivery Point	Current (1)	Following completion of the Project		Firm	Interruptible	
	(a)	(b)	(c)	(d)	(e)	(f) = (b) - (c) - (d)
1. Summit Lake to Terrace	35	115	65	22	17	28
2. Terrace to Kitimat	35	50	-	3	8	47
3. Terrace to Prince Rupert	28	50	45	3	6	2

(1) Current operational capacity under the current configuration of the PNG-West system: One compressor at Station R1 operational.

(2) The Firm and interruptible demand in Line 1 (39 MMSCFD) includes the demand from customers from Vanderhoof to Terrace (20 MMSCFD) and also the demand downstream from Terrace located in Kitimat (11 MMSCFD) and Prince Rupert (9 MMSCFD). Due to rounding, sums do not exactly match the total.

(3) The capacity contracted through the RECAP process shown on line 1 column c (65 MMSCFD) includes the capacity required by a RECAP shipper in Terrace (20 MMSCFD) as well as by the two RECAP shippers located in Prince Rupert (45 MMSCFD)

Further, PNG states:

> From a hydraulic perspective, after gas is delivered to Terrace (Line 1), it can then either be consumed in Terrace, or directed to either Kitimat or Prince Rupert, with the volumes dependent on the relative loads at each location… The remaining capacity of 28 MMSCFD [million standard cubic feet per day] to Terrace (line 1 column f) can be used to meet the interruptible demand on PNG-West during design-day conditions… PNG

designs its system based on Extreme Value Analysis which considers a 20-year return period for firm customers and reviews historical peak day loads which are typically much higher than the average demand… PNG does not consider interruptible (IT) demand as a system capacity design consideration. This includes demand from BC Hydro, who is PNG's largest interruptible customer and has consumed up to 12 MMSCFD on an irregular basis.

In response to BCUC IR 2.4.1, PNG stated:

> The Project has been designed to meet the end point pressure and volumetric delivery needs of existing and newly contracted customers resulting from the RECAP [process for the allocation of reactivated capacity] capacity auction process. While the table provided in response to Question 2.4 indicates residual capacity on the system from Summit Lake to Terrace, and Terrace to Kitimat, these are a result of the hydraulic design requirements necessary to meet customer needs on the downstream end of the NPS 8 section of the transmission system near Prince Rupert. As evidenced by the NPS 8 Terrace to Prince Rupert approximate residual capacity of approximately 3 MMSCFD, and a need to allow for inaccuracy and precision ranges of PNG's model, there is no opportunity for reducing project scope.

48.1 Please clarify whether the peak firm demand in the table above represents historical peak load or forecasted peak demand based on Extreme Value Analysis.

48.1.1 If historical peak load, please provide values for the forecasted peak demand based on Extreme Value Analysis.

48.2 Please provide a detailed explanation of the hydraulic design requirements which necessitate the 28 MMSCFD residual capacity on the Summit Lake to Terrace system.

48.2.1 Please explain the impacts upon PNG's ability to serve firm customer demand if the Summit Lake to Terrace system was designed to have zero available capacity on the Summit Lake to Terrace system (i.e. a maximum capacity of approximately 87 MMSCFD).

48.3 Please explain whether PNG could satisfy the hydraulic design requirements to serve downstream demand with capacity on the Summit Lake to Terrace system of less than 115 MMSCFD.

48.3.1 If yes, please provide the minimum capacity required, and a detailed explanation of any assumptions around the minimum capacity requirement. Please also explain whether PNG would require all aspects of the Project scope to meet this minimum capacity on the Summit Lake to Terrace system.

48.3.1.1 Please discuss whether PNG considered Project alternatives that would reduce the amount of residual capacity on the system.

48.4 Given that PNG states that the 28 MMSCFD of spare capacity on the Summit Lake to Terrace system can be used to meet interruptible demand on PNG-West during design-day conditions, please explain how serving interruptible demand during design-day conditions affects PNG's hydraulic design requirements.

48.4.1 Please clarify whether PNG would be able to serve all firm load downstream of Terrace system under design-day conditions if the 28 MMSCFD of spare capacity on the Summit Lake to Terrace system was used to meet interruptible demand.

48.5 Please estimate the precision range of PNG's model.

B. DESCRIPTION AND EVALUATION OF ALTERNATIVES

49.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1 (Application), Section 4, pp. 40-41, 46, 49-50, 52; Exhibit B-7, BCUC IR 10.5, 12.5, 12.6 Attachment BCUC IR 11.3
Description and Evaluation of Alternatives

On page 41 of the Application, PNG states:

> PNG notes that the financial analysis presented in Section 4 to provide a comparison amongst alternatives relies on Association for the Advancement of Cost Engineering International (AACE International) Class 5 definition level estimates to ensure a fair comparison amongst the identified alternatives.

In response to BCUC IR 10.5, PNG stated:

> The expected accuracy of the Class 5 cost estimates used for the purposes of alternatives evaluation is 100%/-50%. Class 5 estimates were only used in instances where for a given Project element one or more feasible alternatives had no merit for further advancement and estimate refinement. This was applicable for the Interconnect Facilities and the R5 to Terrace By-Pass Pipeline scope element evaluations.
>
> Class 3 and 4 estimates were used for all other project elements during alternatives evaluation where feasible alternatives existed.

On page 46 of the Application, PNG provides cost estimates for alternatives considered for the Existing Compressor Station Reactivation Scope Element, which are noted to be $20.86 million for Reactivation Scenario 1, $28.65 million for Reactivation Scenario 2, and $24.81 million for Reactivation Scenario 3.

49.1 Please confirm the AACE International Class definition level for the above noted cost estimates for alternatives considered for the Existing Compressor Station Reactivation Scope Element (i.e.: Class 3, 4 or 5).

49.1.1 If Class 5, please also provide the Class 3 or 4 cost estimate for each alternative, as referred to in response to BCUC IR 10.5, or provided reference if provided in the Application, Appendices or previous IR responses.

On pages 49-50 of the Application, PNG provides cost estimates for alternatives considered for the New Compressor Stations Scope Element, which are noted to be $6.29 million for Alternative R5A, $10.27 million for Alternative R5B, and $5.68 million for Alternative R5B.

49.2 Please confirm the AACE International Class definition level for the above noted cost estimates for alternatives considered for the New Compressor Stations Scope Element (i.e.: Class 3, 4 or 5).

49.2.1 If Class 5, please also provide the Class 3 or 4 cost estimate for each alternative, as referred to in response to BCUC IR 10.5, or provided reference if provided in the Application, Appendices or previous IR responses.

In Table 4-10 on page 52 of the Application, PNG provides the evaluation of compressor station R5 alternatives.

In response to BCUC IR 12.5, PNG stated the following in regards to how PNG determined Option R5B should be scored '3' in the 'Present Value' category: "A lifecycle cost analysis was conducted on the

alternatives. R5B was shown to have a 34.6% higher present value cost than the minimum result. Based on the scoring shown in Table 4-2 of the Application, this results in a score of 3 for present value."

PNG filed an amended net present value (NPV) analysis as Attachment to BCUC IR 11.3 with its responses to BCUC IR 1. Tab 'Table 4-10; Summary' shows:

Option #	Option	NPV of Incremental Revenue	Difference from Minimum NPV Option
R5			
1	Centrifugal EMD Electric Purchase	19,934,267	4.7%
2	Centrifugal Natural Gas Purchase	34,194,434	79.7%
3	Reciprocating EMD Electric Purchase	**19,031,208**	0.0%

49.3 Please explain the difference between the lifecycle cost analysis, which determined that alternative R5B has 34.6% higher present value cost than the minimum result (as noted in response to BCUC IR 12.5), and the NPV analysis provided in Attachment to BCUC IR 11.3. Please explain why the former was used in the scoring of the alternatives, versus the latter.

In response to BCUC IR 12.6, PNG stated:

> Capital cost scoring is based on the capital costs shown in Table 9 of Appendix I-1 to the Application. Financial scoring was on a 1-5 scale as shown in Table 4-2 of the Application and is based on the percentage increase in cost compared to the minimum cost alternative. The following table shows the relative costs and resulting scores as provided in Table 4-9 of the Application.

Alternative	Capital Cost ($million)	% Increase from Lowest Cost Alternative	Capital Cost Scoring (1-5)
R5A	6.3	111%	4
R5B	10.2	179%	1
R5C	5.7	100%	5
R5D	Not estimated		0

In Table 4-2 on page 40 of the Application, PNG provides the criteria for financial scoring as follows:

Table 4-2: Criteria for Overall 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 of incremental revenue requirement (average over the entire analysis period) and those alternatives that are within 5% of the alternative with the lowest NPV of incremental revenue requirement and the lowest capital cost.

49.4 Please explain why the capital cost score for alternative R5B scores a '1' versus a '2'.

49.5 Based on the previous two IR responses, if the scoring should be different than that provided in Table 4-10, please provide an updated Table 4-10 with updated scoring. Please identify whether the updated scoring impacts the alternative that results in the highest overall score and PNG's selection of its preferred alternative.

C. PROJECT DESCRIPTION

50.0 Reference: PROJECT DESCRIPTION
Exhibit B-7, BCUC IR 16.1
Methane Emissions

In response to BCUC IR 16.1, PNG provided a summary of questions from PNG and responses by the BC Oil and Gas Commission (BC OGC). The summary includes the following response from the BC OGC to a PNG question regarding grandfathering of permitted emission limits:

> There is no grandfathering of methane requirements based on discharge permit date. These are valid, subsisting permits which currently do grant authorization to discharge from the equipment as currently designed. Like any statutory decision, the Province, the Ministry of Environment, the Commission could issue orders at any time, should there be further direction regarding limiting venting from vent stacks and NOx emission reduction from turbine drivers. At this time, we are not actively addressing these topics, although given provincial direction these could be addressed in the future. <u>We would encourage the proponent to lower emission intensity if there is an opportunity to do so, although we are not mandating it at this time.</u> [Emphasis added]

50.1 Please identify the components of the RECAP Project which provide PNG with an opportunity to lower the emission intensity of its compression stations.

50.1.1 Please quantify the emission intensity reductions (e.g. methane, NOx, SOx) that are expected following the completion of the RECAP Project.

Please explain whether PNG is not pursuing emission intensity reductions as part of the RECAP Project scope. If so, please explain why emission reductions are not being pursued. Further in response to BCUC IR 16.1, the following PNG question and BC OGC answer is provided:

> Q5. What are emissions requirements for new diesel generators or natural gas generators if installed after 1 Jan 21.
>
> A. We do not have specific emission requirements when it comes to sources under permit authorization. Instead, we are looking to understand that the Best Achievable Technology is being implemented – often we will see this mirror the emission requirements stipulated within Schedule 1 of the Oil & Gas Waste Regulation. We are also looking to see that the discharges are able to be in compliance with Provincial Ambient Air Quality Objectives. Given that new objectives have been introduced for NO2 & SO2, for older infrastructure we often request that assessment be made against the new & former objectives.

50.2 Please explain whether PNG is implementing the "Best Achievable Technology" for the new generator components of the RECAP Project.

51.0 Reference: PROJECT DESCRIPTION
Exhibit B-7, BCUC IR 19.3, 19.4, 19.5.1
Pipeline Restoration

In response to BCUC IR 19.3, PNG stated:

> Tight crack detection, identification and sizing may require applying a different ILI technology, such as electromagnetic acoustic transducer (EMAT). No EMAT tool was run during the two ILI runs completed on this pipeline because no EMAT ILI tool is commercially available for NPS 8 natural gas pipeline. <u>This indicates that the health condition of the pipeline in terms of tight crack and stress corrosion cracking (SCC) is unknown.</u>
>
> PNG is seeking a solution to address this uncertainty by the end of the restoration work of the pipeline pertaining to this Application. One of the viable solutions has been identified as completing a detailed engineering assessment in accordance with the CSA Z662 requirements, in conjunction with quantitative risk assessment (QRA) based on the probabilistic approach, to determine the susceptibility of the pipeline to cracking and SCC damage mechanisms based on the probability of pipeline failure due to cracking and SCC. <u>This proposed engineering assessment would supplement the recently completed engineering assessment study that defined the scope of the restoration work of this pipeline.</u> The proposed engineering assessment and QRA will be based on the crack/SCC findings of the corrosion and dent integrity digs completed by the end of this restoration work. [Emphasis added]

51.1 Please discuss whether the recently completed engineering assessment study referred to in the preamble included any commentary regarding the susceptibility of this pipeline segment to SCC or the probability of pipeline failure due to SCC. If so, please provide a summary.

51.2 Please clarify the timing of the proposed engineering assessment in accordance with the CSA Z662 requirements and the timing of the QRA based on the probabilistic approach.

51.2.1 Please elaborate on PNG's assessment of the urgency to determine the health condition of the pipeline in terms of tight cracks and SCC.

51.3 Please explain how PNG has accounted for any risks to Project Cost and/or Schedule that may result from the identification of critical SCC features during the restoration work of the pipeline pertaining to this Application.

In response to BCUC IR 19.4, PNG stated: "PNG is agreeable to filing the engineering assessment on the NPS 8 mainline pipeline between Terrace and Salvus on a confidential basis as part of the evidentiary record in this CPCN proceeding. PNG expects the engineering assessment on the NPS 8 mainline pipeline between Terrace and Salvus to be completed in mid to late June 2021."

51.4 Please provide a copy of the engineering assessment on the NPS 8 mainline pipeline between Terrace and Salvus.

In response to BCUC IR 19.5.1, PNG stated:

> The main difference between the initial restoration scope and the latest scope is incorporating corrosion growth rates, field inspection data, and the actual material properties instead of the minimum specified values or assumptions into the assessments as more information has become available in the past few months. This enabled the engineering assessment to identify the integrity features whose severities become critical during the course of this project and allows PNG to address such integrity features before considering the pipeline fit for service at the licensed MOP. <u>As a result, the latest restoration scope has 26 more remediation sites. PNG is seeking to utilize a CSA Z662-19 compliant alternative for performing restoration work through fieldwork to address as many as 30 sites.</u> The alternative is to conduct a Level III FFS engineering assessment on the identified dent defects to support the decision of not remediating the defects passing the assessment criteria. [Emphasis added]

51.5 Please clarify whether the costs associated with the latest restoration scope, which includes 26 additional remediation sites, have been accounted for in the current Project cost estimate.

51.5.1 Please clarify whether the 26 additional remediation sites are sites which include "integrity features whose severities become critical during the course of this project".

51.6 Please clarify whether the costs associated with "performing restoration work through fieldwork to address as many as 30 sites" have been accounted for in the current Project cost estimate.

51.7 Please explain how many dent defect sites PNG intends to assess through a Level III FFS engineering assessment.

51.7.1 Please discuss whether PNG has estimated how many identified dent defects are expected to pass the assessment criteria.

51.7.2 Please clarify whether the costs associated with performing restoration work for the identified dent defects which do not pass the assessment criteria have been accounted for in the Project cost estimate or in the Project contingency/Quantitative Risk Analysis.

52.0 Reference: PROJECT DESCRIPTION
Exhibit B-7, BCUC IR 28.1
New Right of Way Agreements

In response to BCUC IR 28.1, PNG provided the following table:

Project Element	Landownership Type	PID	SRW Agreement	OGC Permit
Top Speed – Skeena Interconnection	Private	029-411-424	Permanent – not yet acquired	Required
Top Speed – Totem Interconnection	Vacant Crown	NO PID	Permanent – Not yet acquired	Required
Port Edward	Crown MOT	017-006-830	Permanent – Not yet acquired	Required
R5 Compressor	Private – PNG Land	006-205-968	Permanent - PNG owned	Required
R6 Compressor	Crown	Crown Land Pin 2262750 Private Land PID 028-270-291	Permanent – Not yet acquired	Required

Project Element	Landownership Type	PID	SRW Agreement	OGC Permit
Terrace Bypass	PNG has an existing ROW. It is a mixture of private, municipal, Crown, MOT and Parks. If additional ROW is required, it will be a new SRW.	006-205-968 029-304-008 029-322-128 029-322-120 029-304-075 029-304-075 PIN 15949320 015-318-591 015-322-866	SRW Agreement 34724D and Doc348345	Required

52.1 Please provide an update regarding the status of acquiring the rights of way identified in the above table. Please include an expected date for finalizing the right of way agreements.

D. PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACTS

53.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACTS
Exhibit B-1, Section 1.1.5.2, p. 8, Section 6.5.3, p. 131; Exhibit B-7, BCUC IR 37.1, 37.1.1, 37.3, 37.3.1
Future Rate Impact Mitigation

On page 8 of the Application, PNG states:

> PNG expects that the revenues and margin associated with the Project will more than offset the combined cost of service impact of both the proposed Project and the Salvus to Galloway project over the average initial 20-year term of the TSAs [Transportation Service Agreements] executed following RECAP. As a result, all PNG customers will have lower rates than they otherwise would in the absence of the new revenues and margin.

On page 131 of the Application, PNG provides Table 6-12 showing an example of how various deferral accounts, including the LVIDA, can be used to mitigate rate volatility in the initial years of the TSAs, illustrating a constant annual rate increase of 1.8 percent. PNG states that "[t]he example also illustrates that new industrial customer revenues in excess of the proposed Project's cost of service will be captured in the LVIDA for future amortization and to provide flexibility in avoiding rate shock if and when the new industrial customer TSA contracts expire, as well as to mitigate rate impacts of unforeseen circumstances in the future."

In response to BCUC IR 37.1, PNG stated:

> The illustrative example provided in Table 6-12 was provided to communicate that with the approval of Reactivation Project and the Salvus to Galloway projects, there is a high likelihood of volatility in customer rates during the lengthy period of construction of the two projects unless mitigation strategies are employed. The illustrative example is not meant to suggest that customers will experience either rate increases or rate decreases.

In response to BCUC IR 37.1.1, PNG stated that "[b]y inference, PNG's customers will experience reduced rates relative to the rates that would be set if the Reactivation Project does not proceed."

53.1 Please clarify whether there is a scenario where PNG customers may experience no rate decrease as a result of the Project due to the use of the LVIDA.

In response to BCUC IR 37.3, PNG stated:

> PNG strongly believes that customer rates should be set with consideration of future risks related to the RECAP customer volumes, including: (i) failure of one or more RECAP customer projects getting completed; (ii) financial failure of one or more of the RECAP customer projects following their completion; and (iii) as mentioned above, termination of one or more of the RECAP Transportation Service Agreements (TSAs) any time prior to full amortization of the investment in the Reactivation Project.

53.2 In PNG's view, please explain, with rationale, who bears the risks related to the RECAP customer volumes identified in the preamble.

53.2.1 For each of the risks identified in the response to BCUC IR 37.3, please summarize how these risks are mitigated by the existing TSAs and Interconnection Agreements.

In response to BCUC IR 37.3.1, PNG stated:

> In the event that PNG did not build a sufficient balance in the LVIDA over the primary term of the TSAs and rather used the RS 80 margin <u>to provide reduced customer rates</u> and RS 80 customers did not extend their TSAs beyond the primary term, PNG would not be able to avoid rate shock. [Emphasis added]

53.3 Under a scenario whereby the RS 80 margin is used to maintain existing rates rather than to reduce customer rates and RS 80 customers did not extend their TSAs beyond the primary term, please explain whether it would still be possible to avoid rate shock as the TSAs expire. If yes, please provide a brief description of how this may be achieved (e.g. through the use of deferral accounts).

54.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACTS
Exhibit B-7, BCUC IR 35.2
Project Cost

In response to BCUC IR 35.2, PNG provided the following breakdown of the Project Management Office (PMO) cost estimate in 2020 dollars:

Cost Category	2021	2022	2023	2024	Total
Project Sponsor	$33,800	$67,600	$67,600	$67,600	$236,600
Project Director	39,000	78,000	78,000	78,000	273,000
Project Manager	135,200	270,400	270,400	270,400	946,400
Admin	62,400	124,800	124,800	124,800	436,800
Sr. Project Engineer	117,000	234,000	234,000	234,000	819,000
Regulatory/Permitting	20,800	41,600	41,600	41,600	145,600
Indigenous Relations	20,800	41,600	41,600	41,600	145,600
Lands / 3rd Parties	20,800	41,600	41,600	41,600	145,600
Environment, Health, and Safety	41,600	83,200	83,200	83,200	291,200
Construction Management	130,000	260,000	260,000	260,000	910,000
Health, and Safety	41,600	83,200	83,200	83,200	291,200
Supply Chain Lead	83,200	166,400	166,400	166,400	582,400
Cost	52,000	104,000	104,000	104,000	364,000
Scheduling	52,000	104,000	104,000	104,000	364,000
Pipeline Engineer	26,000	52,000	52,000	52,000	182,000
Document Management	41,600	83,200	83,200	83,200	291,200
IT	8,320	16,640	16,640	16,640	58,240
Operations	20,800	41,600	41,600	41,600	145,600
Finance	46,800	93,600	93,600	93,600	327,600
Flight, Hotel, Other expenses	110,400	220,800	66,000	66,000	772,800
Legal	33,000	66,000	33,000	33,000	231,000
Commercial Advisor	16,500	33,000	78,000	78,000	115,500
Total	$1,153,620	$2,307,240	$2,307,240	$2,307,240	$8,075,340

54.1 Please discuss what the cost category "Cost" relates to.

54.2 Please provide a breakdown by year and cost category of any PMO costs included in the table provided in response to BCUC IR 35.2 that were included in PNG's 2020 and 2021 revenue requirements used to set BCUC approved delivery rates.

54.2.1 For any such costs, please explain if these amounts are being recovered from ratepayers twice.

55.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACTS
Exhibit B-7, BCUC IR 32.6, 32.7
Maintenance Expenditures

In response to BCUC IR 32.6, PNG confirmed that "all maintenance anticipated to be directly associated with the project assets, or otherwise incremental to PNG's current maintenance requirements for existing assets, are included as [either capital maintenance or under operating expenses under the category "small repairs and consumables]."

In response to BCUC IR 32.7, PNG stated:

> PNG has assumed in its financial analysis that all items that are associated maintenance capital expenditures are capitalized and depreciated over specified asset lives. PNG has assumed in its financial analysis that all items categorized as operating expenses are expensed in the year that they are incurred.

55.1 Please elaborate on how PNG determines whether maintenance activities are categorized as either maintenance capital expenditures or operating expenses.

E. CONSULTATION AND ENGAGEMENT

56.0 Reference: Consultation and Engagement
Exhibit B-1, p. 167; Exhibit B-7, BCUC IR 41.3, BCUC IR 42.3
Consultation and Engagement with Indigenous Communities

On page 167 of the Application, PNG notes engagement with affected Indigenous communities began in November 2020. PNG sent out an introductory letter and Project Fact Sheet to individual First Nation Groups. PNG appended a communications log that includes all correspondence with all 18 First Nations since engagement commenced in November 2020 (confidential Appendix O5); and a log outlining questions, concerns and comments made by First Nations in regard to the overview presentations and PNG responses (Appendix O6).

In response to BCUC IR 41.3, with respect to environmental studies, PNG stated:

> No additional studies have been completed. Further planning since February 2021 has remained focused on desktop level review of potential interactions and risks, pending additional focused engineering, survey and scope definition (i.e. identification of specific dig sites, access and land tenure requirements, stream crossings, etc.).

In response to BCUC IR 42.3, PNG stated:

> <u>PNG will conduct detailed engagement with potentially affected Indigenous communities once environmental (terrestrial and aquatics) and archaeological information have been collected</u>. This information will form the basis for permitting applications as well as construction-related environmental planning documents. All applications and documents will be shared with First Nations for input, identification of potential impacts to rights and title interests and jointly developed mitigations. [Emphasis added]

56.1 Considering no detailed environmental studies have been completed at the time of this Application, please discuss how the BCUC could assess the public interest of this Application from an environmental standpoint.

56.1.1 Please describe the First Nations engagement that PNG considers appropriate for the BCUC to assess the public interest, taking into account the limited scope of the environmental and archeological studies to date.

56.2 Please describe if further rounds of First Nations consultations and engagement activities have been conducted by PNG.

56.2.1 If applicable, please provide an updated communications log (similar to Appendix O5) that summarizes all the correspondence with the First Nations.

56.2.2 If applicable, please provide a list of concerns and issues (similar to Appendix O6) raised by the First Nations groups.

57.0 Reference: Consultation and Engagement
Exhibit B-11, Lax Kw'alaams-Metlakatla IR 3.5-3.6
Consultation and Engagement with Indigenous Communities

In response to Lax Kw'alaams-Metlakatla IR 3.5, PNG states that:

> PNG acknowledges generally that project proponents of new pipelines in British Columbia have entered into impact benefits agreements with First Nations or have

> attempted to enter into impact benefits agreements with First Nations, although the terms of such agreements have not been made available to the public […] PNG expects further discussion with Lax Kw'alaams and Metlakatla regarding potential adverse impacts to their respective interests and consideration of accommodation opportunities throughout this process where appropriate.

In response to Lax Kw'alaams-Metlakatla IR 3.5, PNG stated that:

> PNG is not aware of any BCUC or other regulatory or industry standard requiring impact benefits agreements for economic development projects in British Columbia. PNG acknowledges generally that some project proponents in British Columbia have entered into impact benefits agreements with First Nations, although the terms of such agreements are usually not made available to the public.

57.1 Please explain whether PNG anticipates entering into any impact benefits agreements with First Nations for this Project.

57.1.1 If yes, please explain how PNG has accounted for potential costs relating to impact benefits agreements for this Project, including a breakdown of such costs where applicable.