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May 10, 2018

Sent via eFile

PNG NE 2018-2019 REVENUE REQUIREMENTS
EXHIBIT A-9

Ms. Janet P. Kennedy
Pacific Northern Gas (NE) Ltd.
2550–1066 West Hastings Street
Vancouver, BC V6E 3X2
jkennedy@png.ca; votto@png.ca

Re: Pacific Northern Gas (NE) Ltd. – 2018–2019 Revenue Requirements Application – Project No. 1598936 – Information Request No. 2 – Fort St. John and Dawson Creek

Dear Ms. Kennedy:

Further to your February 28, 2018 filing of the 2018–2019 Revenue Requirements Amended Application, please find enclosed British Columbia Utilities Commission Information Request No.2 for the Fort St. John and Dawson Creek Divisions.

Sincerely,

Original signed by Katie Berezan for:

Patrick Wruck
Commission Secretary

/ad

Enclosure

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Pacific Northern Gas (N.E.) Ltd. – Fort St. John / Dawson Creek Division
2018–2019 Revenue Requirements Application

INFORMATION REQUEST NO. 2 TO PNG(NE)

Table of Contents **Page no.**

A. DEMAND FORECAST REVENUES AND MARGIN

57.0 **Reference: DEMAND FORECAST, REVENUE AND MARGIN**
Exhibit B-1-1, Section 2.1, pp. 25–28; Exhibit B-5, BCUC IR 6.1
Small industrial sales deliveries and margin

In British Columbia Utilities Commission (BCUC) Information Request (IR) 6.1 Pacific Northern Gas (N.E.) Ltd. (PNG[NE]) states:

> The Decision 2017 deliveries are lower than actual by approximately 70,000 GJ as the Decision 2017 forecast was made in early 2016 when it was anticipated that the liquid nitrogen plant's natural gas requirements would end mid-2017 as they were expected to convert to electric power to be supplied via BC Hydro's new transmission line at that time. This did not come to pass.

57.1 Why did the liquid nitrogen plant remain gas powered after mid-2017? Please discuss.

57.2 When does PNG(NE) anticipate the liquid nitrogen plants conversion from gas to electric power will occur? Has PNG(NE) been in discussions with the plant operator to forecast a switch date? Please elaborate.

58.0 **Reference:** **DEMAND FORECAST, REVENUE AND MARGIN**
Exhibit B-1-1, Section 2.2.2, pp. 29–30; Exhibit B-5, BCUC IR 8.4
Company use gas requirements

In BCUC IR 8.4 PNG(NE) states that: "The forecast has been derived averaging the prior three years of line heater and office usage as a percentage of total deliveries multiplied by the test year deliveries."

58.1 Why does PNG(NE) average over a three-year period when calculating line heater and office usage when it calculates customer's forecast deliveries based on review of historical usage over a five-year period?

58.2 Does PNG(NE) utilize a similar time weighted methodology, giving emphasis to the most recent two years of usage as it does for its customer forecast? Please explain.

B. OPERATING AND MAINTENANCE EXPENSES

59.0 **Reference:** **OPERATING AND MAINTENANCE EXPENSES**
Exhibit B-1-1, Section 2.4, p. 35; Exhibit B-5, BCUC IR 9.1 and 9.2
Account 867 – Regulating Stations and Account 875 – Mains and Services

In response to BCUC IR 9.1, PNG(NE) states:

> Maintenance and inspection activities were not required as they were captured during other capital project work in the area in 2017 where new equipment was installed. These are normally operational activities and will be required to be completed as part of our Integrity Management Plan.
>
> The new provision for contractor services is required for the specific skill sets needed to ensure safe and reliable operation for station valves. Valve specialists will perform this task.

59.1 Please discuss if a similar level of contractor services is expected annually into the foreseeable future. Please explain why or why not.

In response to BCUC IR 9.2, PNG(NE) states:

> 2017 was an abnormally low year for economic activity in PNG(NE) compared to prior years. The Test Year 2018 forecast is less that the 5-year average as Test Year 2018 factors in the recent experience of reduced new services in 2017, as well as the general economic conditions in the region.

Table 18 in the Amended Application shows the following actuals for 2013 to 2017, respectively: $153,000, $187,000, $85,000, $151,000 and $93,000, and forecasts for Test Years 2018 and 2019 as $165,000 and $168,000, respectively.

59.2 Staff calculates that the average actual cost for the past five years is $134,000, and that the forecast for Test Years 2018 and 2019 is more than the average actual cost for the past five years. Please discuss this observation and explain why the forecast for Test Years 2018 and 2019 should not be based on the historical average of actuals from 2013 to 2017.

59.3 Please confirm, or explain otherwise, that the 2017 actual cost is excluded from the calculation of the forecast for Test Year 2018.

59.3.1 If confirmed, please discuss if including the 2017 actual costs in the calculation of the forecast for Test Year 2018 would help smooth the effects of any one "abnormal" year.

59.4 Please discuss if the "reduced new services in 2017" is expected to continue in Test Years 2018 and 2019. Please explain why or why not.

59.4.1 If yes, please explain why the forecast for Test Years 2018 and 2019 should not be closer to Actual 2017.

60.0 **Reference: OPERATING AND MAINTENANCE EXPENSES**
Exhibit B-5, BCUC IR 10.1, 10.2, 13.1.1, 13.7.1 and 13.7.3
Operating labour

In response to BCUC IR 10.2, PNG(NE) states:

> As per revised schedules Actual 2016 and 2017 operating labour expenses were $187,000 and $97,000 lower than Decision 2016 and 2017, respectively. The 2016 variance was primarily due to two budgeted temporary construction positions that were not filled. The 2017 variance was primarily due to two summer student positions that were not filled, late hiring of two temporary construction workers.

60.1 Please explain why it was not necessary to fill the two budgeted temporary construction positions in 2016 and the two summer student positions in 2017.

60.2 Please discuss the number of temporary construction positions and summer student positions forecast for Test Years 2018 and 2019 compared to Actuals 2016 and 2017, and why these positions are necessary for the test period.

In response to BCUC IR 10.1, PNG(NE) provides the following table:

	FSJ/ DC Operating & Maintenance					
Headcount	Test Year 2019	Test Year 2018	Actual 2017	Actual 2016	Test Year 2017	Test Year 2016
Bargaining Unit	25	25	25	25	25	25
Non Bargaining Unit	2.7	2.7	1.8	1.8	1.8	1.8

60.3 Please discuss if the temporary construction positions and the summer student positions are included in the above table.

In response to BCUC IR 13.1.1, PNG(NE) states:

> **Labour**
>
> PNG(NE) has provided an analysis of the labour cost variances for Decision 2017 to Actual 2017, and Actual 2017 to Test Year 2018 on a confidential basis. The Actual 2017 to Decision 2017 unfavourable variance is net of cost savings from a position vacancy. The Test Year 2018 to Actual 2017 positive variance is net of added costs for the NE Engineer position planned to be hired mid-2018.

In response to BCUC IR 13.7.3, PNG(NE) states:

> The NE Project Engineer position will provide engineering support for all PNG(NE) divisions. The position will be based in FSJ and the associated costs will be allocated on a prorate basis to each division based on the number of customers for each division. This is similar to the prorate allocation of the NE Manager of Operations costs which are split 60% to FSJ, 30% to DC and 10% to TR.

In response to BCUC IR 13.7.1, PNG(NE) provides the following:

Position	Expected to begin
Records Clerk	End of Q2 2018
Project Engineer NE	End of Q2 2018

The forecast total cost (salary and benefits) of these positions is approximately $196,000 for Test Year 2018 and $296,000 for Test Year 2019. PNG(NE) notes that the Records Clerk position is based in Terrace and the costs of the position have been budgeted in PNG-West and are included in the cost pools for allocation under the shared services cost allocation methodology.

60.4 Please provide the total forecast labour expense for the new NE Engineer for each of Test Years 2018 and 2019 broken down by BCUC account code for each of PNG(NE)'s divisions.

61.0 **Reference: OPERATING AND MAINTENANCE EXPENSES**
Exhibit B-5, BCUC IR 11.1, 11.2 and 16.3
Operating expenses - other

In response to BCUC IR 11.2, PNG(NE) states:

Employee Expenses

The Decision 2017 vs Actual 2017 variance is primarily due to the Manager of Construction position vacancy for four months in the year. The Test Year 2018 vs Actual 2017 variance is reflective of the vacant manager position being filled.

61.1 Please confirm when the Manager of Construction position was filled.

61.2 Please confirm, or explain otherwise, that the forecast employee expenses and wages for Test Year 2018 has been adjusted, if applicable, to reflect only the months that the Manager of Construction position was filled.

In response to BCUC IR 11.2, PNG(NE) states:

Training Fees and Dues

The Decision 2017 vs Actual 2017 variance was primarily due to unforeseen fusion training that was required for integrity purposes. The Test Year 2018 vs Actual 2017 variance is reflective of training activities returning to normal.

61.3 Please discuss why the Actual 2016 training fees and dues were $17,272 less than Decision 2016.

61.4 Please discuss why Decision 2017 training fees and dues of $36,904 is a closer reflection of "normal" training activities than Actual 2016 and Decision 2016 costs of $10,725 and $27,997, respectively.

In response to BCUC IR 11.2, PNG(NE) states:

Contractors

The Actual 2017 vs Decision 2017 variance was due to preliminary work on the Integrity Management Plan with Dynamic Risk and an early start on the geographical information system (GIS) initiative.

61.5 Please provide a breakdown of the variances of the contractors costs for Test Years 2018 and 2019, and Actual 2017 compared to Decision 2017. Please ensure that the variance caused by the Integrity Management Plan with Dynamic Risk and the Geographical Information System (GIS) initiative is identified, where applicable.

In response to BCUC IR 11.2, PNG(NE) states:

> **Materials**
>
> The Actual 2017 vs Decision 2017 variance was primarily due to less line repairs than forecast and odorant not being purchased in 2017. The Test Year 2018 vs Actual 2017 variance is reflective of the need of purchasing odorant in 2018 and station yard improvements.

In response to BCUC IR 16.3, PNG(NE) confirmed that "odorant is not planned to be purchased in Test Year 2019."

The table provided in response to BCUC IR 11.1 shows material cost increases of $69,269 for Test Year 2018 compared to Actual 2017 and $3,561 for Test Year 2019 compared to Test Year 2018.

61.6 Please explain why there were less line repairs done in 2017 than forecast and whether the decreased level of line repairs is expected to continue in Test Years 2018 and 2019.

61.7 Please provide a breakdown of the $69,269 and $3,561 variances between Test Year 2018 and Actual 2017 and Test Years 2019 and 2018, respectively.

In response to BCUC IR 11.2, PNG(NE) states:

> **Licenses, Permits, Land Rights**
>
> The increase for Test Year 2018 can be attributed to licensing fees for the new Asset Management System.

61.8 Please provide the total consolidated forecast annual licensing fees for the new Asset Management System and the amounts allocated to each of PNG-West and PNG(NE) divisions by BCUC account code for Test Years 2018 and 2019.

61.9 Please discuss the methodology used to allocate the licensing fees for the new Asset Management System.

62.0 **Reference: OPERATING AND MAINTENANCE EXPENSES**
Exhibit B-5, BCUC IR 12.1
Account 670 – Supervision and Account 675 – Mains and Services

In response to BCUC IR 12.1, PNG(NE) states:

> PNG expects the economy in Northeastern BC to continue to have some uncertainty over the course of 2018 and 2019, with both upward and downward pressures. More specifically, there are increases forecasted in commodity prices and mining activity, and also decreases due to issues with softwood lumber tariffs and stalled LNG projects, all leading to an "uncertain economic outlook." Given this uncertainty, PNG(NE) believes it is reasonable to assume a 5-year historical average for the operating costs in Accounts 670 and 675 for Test Years 2018 and 2019 and PNG(NE) has reflected these lower costs compared to Decision 2017 while still continuing to be able to operate and maintain its existing system and ensuring safe, reliable, cost-effective service.

Table 17 in the Amended Application shows the following for Account 670 and 675:

BCUC Account	$000's											
	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
670 Supervision	476	9	2.0%	467	11	2.3%	456	428	462	479	428	431
675 Mains and Services	518	10	2.0%	508	(14)	(2.8)%	523	486	440	440	467	437

62.1 Please confirm, or explain otherwise, that the five-year historical average (2013–2017) for the actual operating costs in Accounts 670 and 675 is $446,000 and $454,000, respectively.

62.1.1 If confirmed, please explain the variance between the forecast costs in Accounts 670 and 675 for Test Years 2018 and 2019 with the five-year historical average in the preceding IR.

63.0 **Reference: OPERATING AND MAINTENANCE EXPENSES**
Exhibit B-5, BCUC IR 13.4 and 13.8
Account 685 – General Operations

In response to BCUC IR 1.13.4, PNG(NE) provided the following table:

CMMS License Fee and Hosting Cost	Test Year 2018				
$	PNG-West	DC	FSJ	TR	Total
	685-110	685-931	685-951		
Amended Application					
License/Hosting (Cost Element 18)	153,000	51,000	51,000	-	255,000
Shared Service Cost Allocation	(52,716)	19,162	30,497	3,057	-
	100,284	70,162	81,497	3,057	255,000
Proper Allocation					
Shared Service Cost Allocation	167,139	31,937	50,828	5,095	255,000
Under (Over) Allocation	66,856	(38,225)	(30,669)	2,038	-

	Test Year 2019				
$	PNG-West	DC	FSJ	TR	Total
	685-110	685-931	685-951		
Amended Application					
License/Hosting (Cost Element 18)	153,000	51,000	51,000	-	255,000
Shared Service Cost Allocation	(53,051)	19,364	30,561	3,126	
	99,949	70,364	81,561	3,126	255,000
Proper Allocation					
Shared Service Cost Allocation	166,581	32,273	50,935	5,211	255,000
Under (Over) Allocation	66,633	(38,091)	(30,626)	2,084	-

In response to BCUC IR 13.8, PNG(NE) states:

> Please see the response to Question 13.4. The allocation of the asset management system (hosting) and licensing costs to Fort St. John (FSJ)/Dawson Creek (DC) for Test Year 2018 is $82,765.

63.1 In response BCUC IR 13.8 PNG(NE) refers to the response to BCUC IR 13.4 for the asset management costs. The response to BCUC IR 13.4 refers to CMMS license fees and hosting costs. Please explain if the CMMS and the asset management costs are related to the same project.

63.2 Please reconcile the asset management system cost of $82,765 for Test Year 2018 with the table provided in response to BCUC IR 1.13.4.

63.3 Please discuss the rate impact of the under (over) allocations identified in the above table for each of PNG's divisions for each test year.

64.0 **Reference: OPERATING AND MAINTENANCE EXPENSES**
Exhibit B-1-1, p. 44; Exhibit B-5, BCUC IR 13.0
Account 685 – General Operations – CMMS and Asset Management System

On page 44 of the Amended Application, PNG(NE) references "licensing costs for the computerized maintenance management system (CMMS)." Further, in response to BCUC IR 13.3, PNG(NE) states that "The primary costs related to this project are system licensing, hosting and technical support costs. This project will commence in Q3 2018, and the CMMS is expected to be functional by Q4 2019."

In response to BCUC IR 13.4 PNG(NE) states that "…the primary cost of the computerized maintenance management system (CMMS) implementation is the system licensing, hosting and technical support costs. On a consolidated basis, these costs are expected to be $255,000 per year." Further, in response to BCUC IR 13.5, PNG(NE) states that "There are no related capital expenditures for the CMMS project. The only incremental cost is for system licensing and hosting which is an annual operating expenditure."

64.1 Please explain the specific functions that CMMS will carry out and why these expenditures are needed for PNG(NE) at this time.

64.1.1 If the asset management system is a separate project/system, please explain the specific functions that the asset management system will carry out and why these expenditures are needed for PNG(NE) at this time.

64.2 Please describe the process that was undertaken to select the system for the CMMS, including any alternatives that were considered.

64.2.1 If the asset management system is a separate project/system, please describe the process that was undertaken to select the system, including any alternatives that were considered.

65.0 **Reference: OPERATING AND MAINTENANCE EXPENSES**
Exhibit B-5, BCUC IR. 15.1
Account 718 – Uncollectible Accounts

In response to BCUC IR 15.1, PNG(NE) states:

> PNG(NE) will implement a formal change in practice effective 2018, as described in response to Question 15.4, whereby those customer accounts that have had active collection efforts by a third party collection agency for greater than one year (in addition to several months of collection efforts by PNG(NE)) will be written-off for accounting purposes. PNG(NE) will continue to monitor its bad debt and collection process to ensure that overdue accounts are monitored effectively.

65.1 Please confirm, or explain otherwise, that the $56,000 and $52,000 bad debt provision for Test Years 2018 and 2019, respectively, reflects the "change in practice effective 2018" mentioned above.

65.1.1 If not confirmed, please explain why.

65.2 Please discuss what the effect the change in practice described above would have on future years' bad debt provision.

66.0 **Reference:** **OPERATING AND MAINTENANCE EXPENSES**
Exhibit B-5, BCUC IR 16.1, 16.2.1 and 16.3; PNG-West 2018-2019 RRA Proceeding, Exhibit B-3, IR 7.4
Account 665/673 – Other

In response to BCUC IR 16.1, PNG(NE) provides the following table:

Activities/Expenses	Test Year 2019	Test Year 2018	Decision 2017	Decision 2016
Brushing	58,000	57,000	55,000	54,000
CIS/DCVG/ILI	56,000	56,000	28,000	39,000
CNR Crossing Fees	25,000	25,000	24,000	24,000
Investigative Digs	19,000	19,000	18,000	18,000
Leak Survey	20,000	20,000	19,000	19,000
Odorant Supply	25,000	25,000	10,000	10,000
Other (Pipeline Operations,	28,000	27,000	27,000	26,000
Purchasing/Warehousing	10,000	9,000	7,000	7,000
Air Survey	7,000	6,000	6,000	6,000
Total	248,000	244,000	194,000	203,000

In response to BCUC IR 16.2, PNG(NE) provides the following table:

	KM of CIS/DCVG/ILI
Test Year 2019	33
Test Year 2018	44
Plan 2017	29
Actual 2017	29
Plan 2016	65
Actual 2016	65

In response to BCUC IR 7.4 in the PNG-West 2018-2019 RRA proceeding, PNG-West states the following with respect to CIS/DCVG cost variances:

- Test Year 2018 vs Decision 2017

  Significantly greater level of effort required for completion of the surveys planned for 2018 relative to Decision 2017 and Actual 2017 due to overall length of pipelines to be surveyed and access requirements including private land owner considerations.

66.1 Please explain why CIS/DCVG/ILI costs are expected to be 44 percent more in Test Years 2018 and 2019 compared to Decision 2016 considering the kilometres of pipeline planned to be inspected in Test Years 2018 and 2019 are 32 percent and 49 percent less than in 2016, respectively.

66.2 Please discuss any expected differences in access requirements for the surveys planned for Test Years 2018 and 2019 compared to Actuals 2016 and 2017, and whether this is expected to increase the survey costs for the Test Years. Please explain why or why not.

66.3 Please discuss the responsibilities for access allowances outlined in PNG(NE)'s Terms and Conditions.

66.3.1 Please discuss the costs that the customer or private landowner is responsible for incurring with respect to access requirements.

66.3.2 Please discuss if PNG(NE) has the right to charge back its customers or private landowners the additional costs incurred when rights of way or access was denied.

In response to BCUC IR 16.3, PNG(NE) confirmed that "odorant is not planned to be purchased in Test Year 2019."

66.4 Please explain why odorant supply should be reduced to the same amount as Decision 2017 at $10,000 for Test Year 2019.

C. ADMINISTRATIVE AND GENERAL EXPENSES

67.0 **Reference: ADMINISTRATIVE AND GENERAL EXPENSES**
Exhibit B-5, BCUC IR. 20.1
Account 723 – Insurance

In response to BCUC IR 19.1, PNG(NE) states:

> PNG(NE) notes that Actual 2016 and Actual 2017 costs are recorded per invoiced amounts that are allocated amongst the divisions based on the proportional amount as per the decision budgets. Note that the D&O and Fiduciary premiums were paid in 2011 and were amortized over a period of six years from 2011 to 2017 in the RRA forecast amounts.

67.1 Please discuss if PNG-West and PNG(NE) have coverage for D&O and Fiduciary insurance for Test Years 2018 and 2019.

67.1.1 If there is coverage, please also identify the amounts and the accounts that these premiums were recorded to for each of the PNG divisions, and explain why they were not recorded to Account 723.

67.1.2 If there is no coverage, please explain why D&O and Fiduciary insurance is no longer necessary.

68.0 **Reference: ADMINISTRATIVE AND GENERAL EXPENSES**
Exhibit B-1-1, Section 2.5, p. 37; Exhibit B-5, BCUC IR. 20.1
Account 725 – Employee Benefits

Table 19 in the Amended Application shows the following:

- Test Year 2019: $769,000
- Test Year 2018: $774,000
- Decision 2017: $781,000
- Actual 2017: $742,000
- Actual 2016: $756,000

In response to BCUC IR 20.1, PNG(NE) provides the following tables:

Employee Benefit Components ($'s)	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016
725 - Employee Benefits					
Canada Pension Plan	83,739	81,300	78,429	69,612	72,775
Life and disability insurance	75,686	71,740	57,138	59,895	58,311
Unemployment insurance	31,615	30,694	37,785	29,245	35,715
Employee Savings Plan	129,234	125,470	116,867	111,055	102,885
Company pension plan	272,343	295,100	318,020	326,000	316,000
Medical and hospital insurance	40,755	40,755	38,762	37,879	36,309
Workers Compensation Board	23,768	23,533	8,750	10,898	9,592
Other Programs	114,276	107,503	127,078	99,942	124,608
	771,416	776,095	782,829	744,526	756,195

Other Program Components ($'s)	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016
Other Programs					
Non-Pension Post Ret. Benefits (non-tax deduct.)	60,326	55,000	103,000	83,000	103,000
Other					
Coffee and water service	8,965	8,789	8,617	5,961	4,391
Educational	4,162	4,080	4,526	550	-
Other	40,823	39,634	10,935	10,431	17,217
	114,276	107,503	127,078	99,942	124,608

68.1 Please reconcile the totals in Account 725 for each of years represented in the above table with the information provided in Table 19 of the Amended Application.

68.2 Please explain why Workers Compensation Board (WCB) benefits are forecast to increase by more than double in Test Years 2018 and 2019 compared to Actual 2017.

68.3 Please explain why "Other" costs under "Other Programs" is forecast to almost quadruple in Test Years 2018 and 2019 compared to Actual 2017.

69.0 **Reference: ADMINISTRATIVE AND GENERAL EXPENSES**
Exhibit B-5, BCUC IR. 20.2
Employees by department/function

In response to BCUC IR 20.2, PNG(NE) provides the following table:

Departments/Functions	Test Year 2019	Test Year 2018	Actual 2017	Actual 2016	Decision 2017
FSJ/DC					
Management	2	2	2	2	2
Engineering	1	1	0	0	0
Sales & Service	15	15	15	15	15
Construction & Maintenance	8	8	8	8	8
Measurement	2	2	2	2	2
	28	28	27	27	27
TR					
Plant Operators	2	2	2	2	2
Total	30	30	29	29	29

69.1 Please provide the number of FTEs for the PNG(NE) divisions for Test Years 2018 and 2019, Actuals 2016 and 2017 and Decision 2016 and 2017 broken down by Department/Functions and expense categories (i.e. operating, maintenance and administrative and general expense).

69.2 Please provide a table with the actual and BCUC approved amounts for wages and benefits for the past five years (2013 to 2017) broken down by BCUC account for each of operating, maintenance and administrative expenses. Please ensure the amounts agree to the amounts on Tab 1, page 2 of the Amended Application (lines 2, 8, 12 and 13).

69.2.1 Please provide explanations for any significant variances between actual and BCUC approved amounts identified in the table requested in the preceding IR.

D. DEPRECIATION

70.0 **Reference: DEPRECIATION**
Exhibit B-1-1, pp. 51–53 and Appendix C; Exhibit B-5, BCUC IR 25 and 27
Net salvage – rate impact

In its response to BCUC IR 25.2, PNG(NE) provides the Test Year 2018 and Test Year 2019 rate impact of incorporating the negative salvage values recommended in the Depreciation Study, as "…approximately 7.1% in Test Year 2018 and a very minor decrease in rates of approximately 0.1% in Test Year 2019 compared to the rates for these test periods presented in the Amended Application."

70.1 Please explain why a rate decrease, as opposed to rate increase, would be expected in Test Year 2019.

70.2 In the event that the negative salvage values recommended in the Depreciation Study were incorporated by PNG(NE), please discuss if there is an expected trend in the rate impact that this would have beyond 2019? For example, would rate decreases be expected to continue and would the rate decreases become more significant? Please provide a detailed explanation.

In its response to BCUC IR 25.4.1, PNG(NE) states: "In the event that Concentric's recommendation regarding negative salvage values were adopted, PNG(NE) would consider a transition period given the significant rate impact from making this change."

In its response to BCUC IR 27.1, PNG(NE) states: "Newfoundland and Labrador Hydro, have filed a current proposal where they have included a gradual phase in of net negative salvage into their proposed depreciation rates."

70.3 Please discuss how a transition period could be implemented from a regulatory accounting perspective, the number of years that PNG(NE) would consider appropriate and provide an illustrative example.

70.3.1 Please describe how the gradual phase-in of net negative salvage will be implemented in the Newfoundland and Labrador proposal and discuss how this differs from PNG(NE)'s transition period described in the preceding IR.

In its response to BCUC IR 25.5, PNG(NE) states:

> [i]f Concentric's recommendations regarding negative salvage accounting were adopted, PNG(NE) submits that it would likely record the negative salvage accrual collected from customers in a rate base credit deferral account. Any actual costs incurred in the future for asset retirements and abandonments would then be recorded in the same deferral account.

70.4 Please provide an illustrative example of recording the actual costs incurred in the future for asset retirements and abandonments in the rate base deferral account.

70.4.1 Please confirm, or explain otherwise, that the asset retirements and abandonments would be recorded as a debit to the rate base deferral account.

70.4.2 Please explain how the asset retirements and abandonments recorded in the rate base deferral account would be amortized into rates. Please confirm that additional future approvals from the BCUC would be required.

70.5 Please provide an illustrative example of the annual accounting entry that would be required for the net salvage depreciation provision.

70.6 Please discuss what is meant by the term, "Life Aspect Depreciation Provision" included in the response to BCUC IR 25.5.

The following statement is included on pages I-4 and I-5 of the Depreciation Study:

> The reason for the lower revenue requirements with the accrual of net salvage is the impact of the accruals on rate base. That is, as net salvage accruals are recorded to the depreciation reserve, the accumulated depreciation balance in the reserve increases and reduces subsequent determinations of rate base in future periods.

70.7 Please discuss if the method of accounting for negative salvage described on pages I-4 and I-5 of the Depreciation Study and referenced above in the preamble is the same as the method of accounting described by PNG(NE) in its response to BCUC IR 25.5. If there are differences between the two methods, please discuss the differences and specify if the differences between the two methods results in different costs to be included in the proposed revenue requirement.

71.0 **Reference: DEPRECIATION**
Exhibit B-1-1, pp. 51–51 and Appendix C; Exhibit B-5, BCUC IR 26
Plant gains and losses deferral account

In its response to BCUC IR 26.1.1 PNG(NE) states that it: "…believes that the plant gain losses deferral accounts for salvage values and retirement costs would no longer be required in the event that all of the net salvage values recommended in the Depreciation Study were adopted by PNG(NE)."

71.1 Please provide a description of the type of items that are included in each category of the plant gains and losses deferral account.

71.2 Please explain why the "extraordinary" and "ordinary" categories of the plant gains and losses deferral account would still be required in the event that negative salvage accounting was adopted by PNG(NE).

In its response to BCUC IR 26.1, PNG(NE) provides a table of the additions and amortization of the different categories in the plant gains and losses deferral account.

71.3 Please provide the approximate FSJ/DC Division rate impact for each of Test Year 2018 and Test Year 2019 related to the combined amortization expense for the salvage value and retirement costs categories of the plant gains and losses deferral account.

72.0 **Reference: DEPRECIATION**
Exhibit B-1-1, p. 53 and Appendix C; Exhibit B-5, BCUC IR 28
US Generally Accepted Accounting Principles

In its response to BCUC IR 28.1, PNG(NE) describes ASC 410-20-25-4 of US Generally Accepted Accounting Principles (GAAP) as it relates to negative salvage accounting.

72.1 Based on the content of ASC 410-20-25-4 provided in response to BCUC IR 28.1, please discuss if PNG(NE) considers negative salvage accounting for asset retirement obligations which arise from legal obligations to be in accordance with US GAAP.

72.1.1 Approximately what percentage of PNG(NE)'s asset retirement obligations for the FSJ/DC Division, arise from legal obligations?

In its response to BCUC IR 28.1, PNG(NE) states that "PNG(NE) does not record a provision for the estimated cost to ultimately retire assets as it is not possible to make a reasonable estimate of the fair value of the liability due to the indeterminate timing and scope of the asset retirements."

72.2 Please reconcile the statement in the preamble that "it is not possible to make a reasonable estimate of the fair value of the liability due to the indeterminate timing and scope of the asset retirements" with Concentric's recommendations in the Depreciation Study for specific negative salvage percentages.

73.0 **Reference: DEPRECIATION**
Exhibit B-1-1, Appendix C; Exhibit B-5, BCUC IR 29
Negative salvage – specific accounts

In its response to BCUC IR 29.1 PNG(NE) states that: "the negative 10 percent is low and that negative 25 percent would be a more reasonable expectation for the equipment" in Account 418.

73.1 Please elaborate on why 25 percent is considered to be a more reasonable expectation for the equipment in Account 418 as compared to the peer comparison net salvage value of negative 10 percent.

74.0 **Reference: DEPRECIATION**
Exhibit B-1-1, p. 53 and Appendix C; Exhibit B-5, BCUC IR 30
Depreciation rates

In its response to BCUC IR 30.2, PNG(NE) describes the Average Life Group Procedure (ALG), Equal Life Group Procedure (ELG) and Amortization Accounting. PNG(NE) states that:

> The other procedure commonly used for other Canadian and North American utility companies is the Equal Life Group (ELG) procedure. As compared to the ALG procedure, the ELG procedure is considered to more accurately estimate the actual consumption of a company's fixed assets and the most mathematically correct procedure for capital recovery.

74.1 In the Depreciation Study, Concentric states that "ELG procedure is considered to more accurately estimate the actual consumption of a company's fixed assets and the most mathematically correct procedure for capital recovery." Please discuss if PNG(NE) agrees with this statement and if so, please elaborate on the reasons why the ALG procedure has been used to calculate the annual and accrued depreciation for PNG(NE), as opposed to the ELG procedure.

74.2 Please confirm how long PNG(NE) has used the ALG method to calculate annual and accrued depreciation.

74.3 If the ELG procedure were used to calculate depreciation rates and the negative salvage values recommended in the Depreciation Study were incorporated by PNG(NE), please provide a discussion on the impact, if any, that using the ELG procedure as opposed to the ALG procedure would have on the annual provision for net salvage.

75.0 **Reference:** **DEPRECIATION**
Exhibit B-1-1, p. 52 and Appendix C; Exhibit B-5, BCUC IR 32
Land rights

In its response to BCUC IR 32.3, PNG(NE) indicates that it "is not aware of any other Canadian gas distribution utilities that use the same methodology for Land Rights as proposed by PNG."

75.1 Please confirm, or explain otherwise, that if other Canadian gas distribution utilities don't apply the same methodology as PNG(NE), then the normal accounting process is to amortize land rights.

E. DEFERRAL ACCOUNTS AND AMORTIZATION

76.0 **Reference:** **DEFERRAL ACCOUNTS**
Exhibit B-1-1, p. 55; Exhibit B-5, BCUC IR 33; PNG(NE) 2017 Demand-Side Management Annual Report, dated April 30, 2018
Demand-side management deferral account

On page 55 of the Amended Application, PNG(NE) states that "The amortization in Test Year 2018 and Test Year 2019 reflect actual DSM expenditures incurred of $55,000 in 2015 and $16,000 in 2016, and $33,000 in 2017 and forecast expenditures of $165,000 in Test Year 2018."

In its response to BCUC IR 33.1 PNG(NE) states that "DSM expenditures approved for 2018 under Order G-203-15A are $410,000, of which $187,000 are allocated to the PNG(NE) FSJ/DC division."

Further, in its response to BCUC IR 33.2, PNG(NE) states that:

> PNG(NE) recognizes that customer uptake on some of its programs has been less than forecast and PNG(NE) is undertaking activities that are expected to improve the impact of its current DSM programs. PNG(NE) will also be launching additional programs in 2018. The 2017 DSM Annual Report will include a description of activities currently in progress. PNG(NE) will file its 2017 DSM Annual Report on or before April 30, 2018.

In its 2017 Demand-Side Management (DSM) Annual Report filed on April 30, 2018, PNG(NE) states that "While PNG has increased the intensity of its activities beginning in early 2018, PNG forecasts that it will remain underspent over the entire three year period of its approved budget."

76.1 Please explain if the forecast 2018 additions of $165,000 to the DSM deferral account reflect the expected underspending indicated in the 2017 DSM Annual Report. If not, please provide the revised forecast additions to the DSM deferral account for 2018.

76.2 Please provide a breakdown of the forecast 2018 DSM deferral account by program.

77.0 **Reference:** **DEFERRAL ACCOUNTS**
Exhibit B-1-1, p. 56; Tab 2, pp. 12–13; Exhibit B-5, BCUC IR 34
DC industrial deliveries deferral account

In its response to BCUC IR 34.1, PNG(NE) states that "The DC industrial deliveries deferral account captures the variance between the forecast and actual margin for two of the three customers in the small industrial sales customer classification."

Further, in its response to BCUC IR 34.2, PNG(NE) states that:

> The industrial deliveries deferral account only captures the impact of delivery variances for customers that PNG(NE) has specifically requested and received Commission approval to include in this deferral account. PNG(NE) has not requested any of the FSJ small industrial sales customer to be included in the deferral account.

77.1 Please confirm the two customers that are captured in the DC Industrial Deliveries deferral account and explain why only these two customers, and not the others in the FSJ/DC Division, have been requested to include in the deferral account.

F. MISCELLANEOUS OTHER INCOME AND CREDITS

78.0 **Reference: MISCELLANEOUS OTHER INCOME AND CREDITS**
Exhibit B-5, BCUC IR 1.35.1 and 35.2
Penalty charges and overheads recovered

In response to BCUC IR 35.1, PNG(NE) states:

> Penalty charges are to be estimated using a historical two-year average which were calculated at the time the Original Application was filed.
>
> In preparing the response to this question, it came to PNG(NE)'s attention that the average for 2016 and 2017 actual penalty charges is in fact $72,000....

In response to BCUC IR 35.2, PNG(NE) states:

> Overheads recovered are estimated using a historical two-year average at the time of the Original Application. The average for 2015 and 2016 actual overheads recovered was $44,000.

78.1 Please explain why the forecast overheads recovered for Test Years 2018 and 2019 are not estimated using the average for 2016 and 2017 actual overheads recovered, consistent with the method used to calculate penalty charges.

G. RATE BASE

79.0 **Reference: RATE BASE**
Exhibit B-1-1, Section 2.1, pp. 26-28, Section 2.13, p.62, 67 and Section 3.1, p. 83, 86;
Exhibit B-5, BCUC IR 37.0
Recurring capital expenditures – new services

In response to BCUC IR 37.1, PNG(NE) states it estimates that approximately 340 new distribution service lines will be installed in each of the Test Years 2018 and 2019.

Tables 12, 13 and 14 in the Amended Application provides PNG(NE)'s actual customer counts for Residential, Small Commercial and Other Customer Classes for 2008 to 2017 as well as the forecasted customer counts for Test Years 2018 and 2019. The forecasted customer counts are summarizes in the table below:

Service Area	Customer Count	Actual 2017	Test Year 2018	Test Year 2019
FSJ	Residential	10,962	11,057	11,192
FSJ	Small Commercial	1,739	1,744	1,752
FSJ	Other - Large Commercial Sales	8	8	8
FSJ	Other - Commercial Transport	14	14	14
FSJ	Other - Small Industrial Sales	6	7	7
FSJ	Other - Small Industrial Transport	16	14	14
DC	Residential	6,312	6,352	6,397
DC	Small Commercial	907	913	915
DC	Other - Large Commercial Sales	13	16	16
DC	Other - Commercial Transport	7	7	7
DC	Other - Small Industrial Sales	4	3	3
DC	Other - Small Industrial Transport	1	1	1
	Total	**19,989**	**20,136**	**20,326**
	Forecast increase per year		**147**	**190**
	Forecast percentage increase per year		**0.74%**	**0.93%**

79.1 There are 340 new distribution service lines forecasted for each of the Test Years 2018 and 2019. The information provided in Tables 12, 13 and 14 of the Amended Application forecasts the total number of new customers in Test Year 2018 to be 147 and the total number of new customers in Test Year 2019 to be 190. Please reconcile these figures and elaborate as to why the 340 new distribution service line forecast for each of the Test Years 2018 and 2019 is reasonable considering the information provided in Tables 12, 13 and 14.

PNG(NE) states in response to BCUC IR 37.2 that the new service lines will be in the FSJ and DC service areas, however the locations of the new service lines are "not specifically identified at this time."

79.1.1 Given that the locations of the new distribution service lines are not identified at this time, please explain the criteria used to estimate the number of new distribution service lines forecasted for Test Years 2018 and 2019.

Tables 36 and 38 of the Amended Application identify variances of $631,790 and $889,816 between the Approved Expenditure and Actual Expenditure for New Services in 2016 and 2017 respectively. PNG(NE) attributes the variances to "the fact that all areas experienced a [*sic*] economic down turn in construction".

79.1.2 Please provide a table comparing the number of new distribution service lines forecast for 2016 and 2017 and the actual number of new distribution service lines installed in 2016 and 2017. Please elaborate on any variances.

79.1.2.1 If variances are present, please discuss if PNG(NE) considered these variances and applied any adjustments when forecasting the number of New Services in Test Years 2018 and 2019.

80.0 **Reference:** **RATE BASE**
Exhibit B-1-1, Section 2.13, p. 62 and 67; Exhibit B-5 BCUC IR 38.0
Planned-recurring capital expenditures – distribution main improvements – couplings, PE2306 replacement and other

On pages 62 and 67 of the Amended Application, PNG(NE) forecast $490,000 in Test Year 2018 and $510,000 in Test Year 2019 for the removal of mechanical couplings.

In response to BCUC IR 38.1, PNG(NE) states that 40 percent of the mechanical couplings have been removed in FSJ and less than 10 percent have been removed in DC. PNG(NE)'s targets for removal for 2016 and 2017 were 100 and 20 for FSJ and DC, respectively. PNG(NE) removed 110 and 115 in the FSJ service area in 2016 and 2017 respectively and 20 were removed each year in the DC service area. PNG(NE) states that "in the FSJ area, 100 are again scheduled to be removed each year. The DC area will be doing further analysis to increase the amount of mechanical couplings to be removed to 30-40."

PNG(NE) further states in response to BCUC IR 38.1.1 that "full removal of all Dressers will not be conducted until 15-20 years in the future."

80.1 Please confirm if the target number of mechanical coupling to be removed in the DC service area in Test Years 2018 and 2019 is 20. In your answer please also confirm that the forecast costs reflect this target number. If not, please provide the target used to forecast the costs for Test Years 2018 and 2019.

80.1.1 Given that the 100 target for the FSJ service area was exceeded in both 2016 and 2017, please explain why the targets for Test Years 2018 and 2019 have not been increased.

80.1.2 Please explain the variance in the forecast costs for Test Years 2018 and 2019, given the same number of mechanical couplings are forecast to be removed in each test period.

80.2 Please provide the unit cost for the removal for mechanical coupling. If different, please provide the unit cost of removal according to service area.

In response to BCUC IR 38.1.4, PNG(NE) states that "failed couplings produce risks to public safety and system integrity. These leaks could potentially happen at any time. Leaking gas can migrate and put numerous other areas under risk of combustion or explosion."

80.3 Please elaborate on the risk assessment undertaken to assess mechanical couplings and the level of risk failing couplings pose to public safety and system integrity.

80.3.1 Given the level of risk identified in the preceding IR and the potential for failure to happen at any time, please discuss the suitability of the 15 to 20 year timescale for completing the removal of all mechanical couplings In your response please identify how PNG(NE) ensures compliance with CSA and any other applicable standards."

On pages 62 and 67 of the Amended Application, PNG(NE) forecast $320,000 in Test Year 2018 and $333,000 in Test Year 2019 for the replacement of PE2306 Pipe.

In response to BCUC IR 38, PNG(NE) states that 2,898 m of PE2306 pipe was forecast and actually removed in 2016 and 1,894 m of PE2306 pipe was forecast and actually removed in 2017. PNG(NE) plans to remove 1159 m and 1200 m of pipe in Test Years 2018 and 2019 respectively. There is no formal estimate available for the DC service area. PNG(NE) states in response to BCUC IR 38.1.2 that it expects the program to be completed within the next 15-20 years.

80.4 Please break down the $320,000 and $333,000 forecasted costs, in table form, according to service areas (FSJ and DC) and elaborate on the criteria used to determine the allocation of costs.

80.5 Please break down the 2,898 m and 1,894 m of pipe removed in 2016 according to service areas (FSJ and DC).

In response to BCUC IR 38.2.4, PNG(NE) states that "underground leaks caused by PE2306 failures produce risks to public safety and system integrity…These underground gas leaks could potentially happen at any time and could migrate, thereby putting other areas under the risk of combustion or explosion."

80.6 Please elaborate on the risk assessment undertaken to assess PE2306 and the level of risk PE2306 failures pose to other areas.

80.6.1 Given the level of risk identified in the preceding IR and the potential for failure to happen at any time, please discuss the suitability of the 15 to 20 year timescale for completing the PE2306 removal program. In your response please identify how PNG(NE) ensures compliance with CSA and any other applicable standards.

On pages 62 and 67 of the Amended Application, PNG(NE) forecasts $461,000 in Test Year 2018 and $480,000 in Test Year 2019 for other distribution mains improvements "for the lowering of distribution main in public thoroughfares to meet the needs of changes to the surrounding roadway and to avoid conflict with new civil works and ensure on-going safety of the pipe."

In response to BCUC IR 38.3, PNG(NE) states that the lowering "may be required" due to infrastructure enhancements or geological changes in the environment.

80.7 Please explain whether the forecast costs relate to specific expenditures.

80.7.1 If so, please provide a breakdown, in table form, of the forecast costs according to forecasted expenditures.

80.7.2 If not, please elaborate on how the forecast costs are estimated.

81.0 **Reference: RATE BASE**
Exhibit B-1-1, Section 2.13, p. 63-64; Exhibit B-5, BCUC IR 40.0
Non-recurring capital expenditures – replace Dawson Creek #1 Gate Station

In response to BCUC IR 40.0, PNG(NE) states that construction of the Dawson Creek #1 Gate Station has not yet commenced, the project is on track for completion in 2018 and "costs incurred to date equal $309,900 for engineering, permitting, and long lead materials and services procurement, with an additional $328,400 in outstanding commitments."

PNG(NE) provided the total project cost by year, in the following table form:

Cost Element			
Eng/Permit/Plan	2017	2018	
Labour	$ -	$ -	
Materials	$ -	$ -	
Contractor	$ 14,000	$ 92,000	
Construction			
Labour	$ -	$ 14,000	
Materials	$ -	$ 230,000	
Contractor	$ -	$ 771,000	Total
Totals	$ 14,000	$ 1,107,000	$ 1,121,000

81.1 Please provide a table comparing the project budgets provided in the table in response to BCUC IR 40.2 against the actual costs to date. Please explain any variances greater than 10 percent.

81.2 What is the percentage portion and dollar amount of contingency that is included in the total project cost.

In response to BCUC IR 40.3, PNG(NE) provided the following information on the schedule and key milestones for the Dawson Creek #1 Gate Station:

- Detailed Design – Complete
- Long Lead Time Materials and Services Procurement – Complete
- Mechanical/Civil/EIC Construction Contract Award – May 2018
- Construction Commencement – June 2018
- Construction Completion – July 2018

81.3 Please confirm that the Mechanical/Civil/EIC Construction Contract Award remains on schedule and will be awarded in May 2018.

81.4 Please confirm, or explain otherwise, that the project remains on schedule for completion in July 2018.

In response to BCUC IR 40.5, PNG(NE) states that:

> No alternatives to the station replacement were considered given the safety and integrity related compliance concerns related to the underground piping, fittings, and the building that need to be addressed. Project scope and cost limiting opportunities related materials were designed into the project and will be realized.

81.5 Please provide a scope of works for the project. Please elaborate on whether the station replacement project scope is on a 'like for like' basis.

81.5.1 If not, please elaborate on, and give examples of, the variances between the existing and planned station. Please provide reasons for the variances (for example equipment upgrades to improve efficiency).

82.0 **Reference:** **RATE BASE**
Exhibit B-1-1, Section 2.13, pp. 64 and 68; Exhibit B-5, BCUC IR 41.0
Non-recurring capital expenditures – Cecil Lake aluminium replacement

In response to BCUC IR 41.2, PNG(NE) states that:

> The skilled trades required for the repair and construction [*sic*] aluminum piping has become increasingly more difficult to source over the course of the last several years. The last remaining contractor known to PNG(NE) has elected to no longer maintain the required certifications. In the event of a pipeline incident, PNG(NE) has no means of enacting repair. Not only does this situation result in a state of non-conformance with maintenance, repair, and integrity management aspects of CSA Z662, but this also subjects PNG(NE), the rate payers, and the general public to risk above tolerable levels. As a result, PNG(NE) believes it is prudent to carry out the project across the 2018 and 2019 test years."

On page 64 of the Amended Application, PNG(NE) states that the piping will be replaced with standard PE piping.

82.1 Please confirm that the project scope is for replacement of the aluminium pipe with the standard PE pipe and that all other aspects of the project are on a 'like for like' basis. If not, please elaborate and provide details of the project scope compared to the existing infrastructure.

82.2 Please elaborate on the risk assessment process undertaken to evaluate the risks associated with limited skilled trades for the repair and construction of aluminium piping.

82.3 Please describe and provide examples of the tolerable levels of risks PNG(NE) uses to undertake risk assessments.

82.4 Please provide a description of the work undertaken by PNG(NE) to date to assess the wider impact of limited skilled trades. In your response, please elaborate on whether PNG(NE) has identified other sections of aluminium pipework and what measures PNG(NE) anticipates it will take to mitigate the identified risks associated with these sections of pipework.

82.5 What is the percentage portion and dollar amount of contingency that is included in the total project cost.

In response to BCUC IR 41.4, PNG(NE) states that a detailed project schedule "has not yet been developed. Engineering, design, and permitting are planned for 2018 with construction to span 2019. Spending and scope planned for 2018 is on track to be completed in 2018."

82.6 Please provide an estimate of when the engineering, design and permitting is anticipated to be complete.

82.7 Please provide an estimate of when the construction is anticipated to start.

83.0 **Reference:** **OPERATING AND MAINTENANCE EXPENSES**
Exhibit B-5, BCUC IR 52.3; PNG-West 2018–2019 RRA proceeding, Exhibit B-1-1, p. 90; Exhibit B-3, BCUC IR 47
Asset records modernization and digital data mapping

On page 90 of Exhibit B-1-1 in the PNG-West 2018–2019 RRA proceeding, PNG-West references the Asset Records Modernization project which is a "multi-year program by PNG to digitize all pipeline and associated facility design and construction records."

Further, in response to BCUC IR 47.2, PNG-West provides the following table with the total project costs for the Asset Records Modernization:

Response:

The total project cost and forecast spend per year is as follows:

	2018	2019	2020 - 2022	
Contractor	$ 207,000	$ 204,000	$ 208,080	
Labour	$ 62,400	$ 67,600	$ 69,200	
Other	$ 16,800	$ 20,400	$ 20,900	TOTAL
	$ 286,200	$ 292,000	$ 298,180	$ 1,472,740

Forecast expenditures in 2020 and beyond are approximate and subject to change based on rate of budget consumption in 2018/2019 relative to the project's overall lifecycle scope.

In response to BCUC IR 9.1.2, PNG-West states:

> For the asset records modernization, digital data mapping and GIS projects, these are annually phased capital projects with improvements realized throughout the years as each one of PNG's assets is digitally captured and effectively "capitalized."

In response to BCUC IR 52.3 in the PNG(NE) 2018–2019 RRA, PNG(NE) states that "The 2018 budget increase is primarily due to the purchase of a tent to store and protect pipe from UV damage ($33,000), as well as activities related to asset records modernization to digitize the physical pipeline system ($15,000)."

83.1 With respect to the table provided in response to BCUC IR 47.2 in the PNG-West 2018-2019 RRA proceeding, please clarify if these are consolidated costs including both PNG-West and PNG(NE).

83.1.1 Please provide a table of total project costs for the Asset Records Modernization project with a breakdown by year, by division (i.e. PNG-West, PNG[NE] FSJ/DC and PNG[NE] TR) and with a breakdown between capital and operating costs.

83.1.2 Please elaborate on the need for the asset records modernization project, including the specific functions of the project.

83.1.3 Please provide details of any alternatives to the Asset Records Modernization project that were considered.

83.2 Please provide a table of total project costs for the Digital Data Mapping project with a breakdown by year, by division (i.e. PNG-West, PNG[NE] FSJ/DC and PNG[NE] TR) and with a breakdown between capital and operating costs.

83.2.1 Please elaborate on the need for the digital data mapping, including the specific functions of the project.

83.2.2 Please provide details of any alternatives to the digital mapping project that were considered.

83.2.3 Please discuss when the activities related to the digital data mapping project is expected to begin and be completed.

84.0 **Reference:** **RATE BASE**
Exhibit B-1-1, p. 64; Exhibit B-5, BCUC IR 42.5, Attachment 1.42a
GIS – justification and need

In its response to BCUC IR 42.5, PNG(NE) provides details of the need for the GIS Project and states that "[i]mplementing GIS technology provides PNG with opportunities for streamlining and standardizing business processes to improve process efficiency and consistency between geographic locations, integrate with key business systems, improve communication and streamline workflows within PNG."

Section 2 of Attachment 1.42a includes information on the GIS project justification.

84.1 Please elaborate on how the GIS Project will:

a) streamline and standardize business processes;
b) improve efficiency and consistency between geographic locations;
c) integrate with key business systems;
d) improve communication; and
e) streamline workflows.

Please provide specific examples for each of the preceding categories.

84.1.1 For each of the above-noted items, please quantify the annual financial benefit, where possible.

85.0 **Reference:** **RATE BASE**
Exhibit B-1-1, p. 64; Exhibit B-5, BCUC IR 1, 42.2, Attachment 1.42a and 1.42b
GIS - benefits

On page 8 of the GIS Business Case, PNG(NE) identifies the following three major categories of benefits of implementing an enterprise GIS: (i) risk reduction; (ii) regulatory compliance; and (iii) simplified business and work processes. Further, on page 12 of the GIS Business Case, PNG(NE) states that it, "wishes to achieve the benefits from the GIS implementation as soon as is practical, and there is a sense of urgency to improve the current processes, tools and data."

On page 6, PNG(NE) further states that:

> …[The] primary motivating factors for moving forward with the PNGISI Project are (1) to develop an authoritative system of record for PNG's asset data; (2) to provide an enterprise-wide system to allow PNG staff (particularly field staff) to operate much more efficiently and consistently; (3) to improve integration between key business systems; (4) to improve capabilities and capacity for reporting and regulatory compliance (i.e. CSA standards, BC Oil and Gas Commission and Technical Safety BC regulations); and (5) to incorporate industry best practices and technology into PNG's operations.

On page 18 of Attachment 1.42b, PNG(NE) includes a list of the potential benefits of the GIS Project.

Further on page 19 of Attachment 1.42b, PNG(NE) states that:

> The primary motivating factors for moving forward with the GIS implementation from PNG Management's perspective are to embrace contemporary industry best practices and technology, develop an authoritative System of Record with regards to PNG's assets, and provide a system which will allow PNG staff (particularly field staff) to operate much more efficiently and consistently than what can be achieved with the

current tools and processes.

On page 4 of Attachment 1.42a, PNG(NE) states that "GIS is a mainstream technology implemented across the North American utility sector due to its recognized strategic and economic value in organizations."

In its response to BCUC IR 42.2 PNG(NE) states:

> The lack of a GIS system is putting PNG at risk of being out of compliance with codes, standards, and regulations. PNG's delay in adopting GIS technology is increasing its exposure to risks related to the safe and reliable delivery of natural gas to its customers.

85.1 Please describe and quantify the economic value of the proposed GIS Project for PNG(NE).

85.2 Please provide details and specific examples of the risk reduction associated with the proposed GIS project as it relates to system integrity, emergency management, and safe and reliable service. Please also discuss any financial benefits associated with the risk reduction for PNG(NE) and quantify, where possible.

85.3 For any other benefits of the proposed GIS project that have not been quantified in the preceding IRs, please identify and describe the benefit and quantify, where possible.

85.4 Please provide an expected forecast of the benefit-to-cost ratio of the GIS project for PNG(NE).

85.5 Please discuss if there are any other specific benefits for ratepayers of the GIS project.

85.6 Please discuss the risks associated with the proposed GIS project and quantify where possible.

86.0 **Reference:** **RATE BASE**
Exhibit B-1-1, p. 64; Exhibit B-5, BCUC IR 1, 42.2; Attachment 1.42a, pp. 8–10 and Attachment 1.42b pp. 56–64
GIS - alternatives

In its response to BCUC IR 42.2, PNG(NE) states:

> The comparison of the alternatives considered was completed in the context of alternatives in GIS configurations and implementation. In the third quarter of 2017, PNG engaged Spatial Vision Group Inc. (SVG) – an engineering/geomatics consultant – to complete an in-depth evaluation of alternative GIS platforms, along with alternative implementations of the preferred technology.
>
> A review of potential vendor solutions was conducted by SVG to identify commercially available GIS oriented technology, product and services offerings that may be a good fit with PNG's requirements. The scope of this review was constrained to include only those solutions that were considered leaders based on industry trends and/or had significant market share in the utilities (and particularly natural gas distribution) sector. An initial assessment of potential candidates was conducted to arrive at a short list of candidates subject to a more thorough assessment that concluded that Esri's ArcGIS platform is currently the de-facto standard for GIS in the utilities sector; industry trends indicate the Esri will continue to occupy this position in the marketplace for the foreseeable future.
>
> SVG considered the following four alternatives for implementation of PNG's GIS:
>
> 1. Greenfield – PNG, using internal resources, implements its GIS from the ground up;

2. AUI Leveraged – PNG teams with AUI to leverage its experience and expertise to implement its GIS;
3. ENSTAR Leveraged – PNG teams with ENSTAR to leverage its experience and expertise to implement its GIS;
4. Outsource – PNG uses a team of contractors to develop and deliver a turn-key GIS.

After comprehensive and informative discussions with both AUI and ENSTAR, it quickly became apparent that the Greenfield option was not a competitive alternative to one that would benefit from the expertise of both AUI and ENSTAR. In addition, the Greenfield option was not consistent with the strategic direction set out for IT implementations at AltaGas' Canadian Utilities. Accordingly, the Greenfield option was dropped from the list of alternatives considered in the detailed evaluation.

The alternatives are also discussed on pages 9–10 of the GIS Business Case, with an assessment of candidate GIS solution vendors outlined on Table 3. Further, pages 56–64 include a detailed assessment of the alternatives.

86.1 Please explain how the information contained in Table 3 of the GIS Business Case, specifically the information related to the vendor Esri ArcGIS, is related to the four alternatives for implementation that are included in response to BCUR IR 42.2 and on page 10 of the GIS Business Case.

86.2 Please explain if there are any other gas distribution companies in Canada outside of the AltaGas group of companies that use Esri's ArcGIS platform for GIS.

86.3 Please clarify if the vendor/product list in Table 3 of Attachment 1.42a and Table 6 of Attachment 1.42b relates to the initial assessment of potential candidates, or the short list of candidates subject to a more thorough assessment.

86.3.1 If the above-noted tables relate to the short list, please provide a list of all GIS vendors that are considered leaders based on industry trends and/or had significant market share in the utilities (and particularly natural gas distribution) sector and identify those that were considered as part of the PNG(NE) GIS Project. For those that were considered, please discuss why they ultimately were not considered an appropriate alternative to short list and for those not considered, please explain why not.

86.3.2 If the above-noted tables do not relate to the short list, please confirm that the three vendors are the only GIS vendors that are considered leaders based on industry trends and/or had significant market share in the utilities (and particularly natural gas distribution) sector.

On page 12 of the GIS Business Case, PNG(NE) states that the, "budget assessment compares the expected costs of each of the GIS implementation alternatives."

Table 5 on page 13 of the GIS Business Case includes a summary table of the alternatives rankings, including quality component scores, schedule component scores and budget component scores.

Further, pages 56 to 61 of Attachment 1.42b includes a detailed analysis of the alternatives and identifies the following alternatives that were considered: AUI, ENSTAR and Outsource.

86.4 Please provide the results of the project cost estimates for each of the four alternatives that were developed in determining the budget component score in Table 5 of the GIS Business Case.

86.5 Please provide a detailed discussion as to whether PNG(NE) considered maintaining the status quo, rather than proceeding with the proposed GIS project and ultimately why this was not considered to be an appropriate alternative.

86.5.1 Please provide a comparison of expected cost benefits and expected cost risks of maintaining the status quo versus GIS implementation.

87.0 **Reference: RATE BASE**
Exhibit B-1-1, p. 64; Exhibit B-5, Attachment 1.42b p. 33
GIS – peer interviews

On page 33 of Attachment 1.42b, PNG(NE) states that SVG held meetings with "two similar gas transmission and distribution utilities, AltaGas Utilities Inc. and ENSTAR (both are subsidiaries of AltaGas Limited).

87.1 Please discuss if PNG(NE) and/or SVG considered expanding the scope of the peer review beyond subsidiaries of AltaGas Limited. Please explain why or why not.

87.2 Please provide any available information on the permeation of GIS technology in other gas distribution utilities in Canada and specifically in BC, other than companies in the AltaGas Limited group.

88.0 **Reference: RATE BASE**
Exhibit B-1-1, p. 64; Exhibit B-5, BCUC IR 42.1 and Attachment 1.42a, Appendix A5
GIS – project schedule

Appendix A5 of the GIS Business Case includes the implementation schedule and milestones.

In its response to BCUC IR 46.1, PNG(NE) states that:

> PNG-West and PNG(NE) (collectively, PNG, in response to this series 42 of questions) are currently defining the organization and planning the implementation of this project. At this time, PNG has identified the major tasks and timeline for the first phase of the project (Phase One) that will implement a useful GIS having a subset of the ultimate data and functionality that will be delivered over the three-year span of the overall project. Included is a task to identify, acquire and migrate spatial data related to the scope of work that will be defined for Phase One. PNG anticipates undertaking a competitive bid process for this part of the project.

88.1 Please confirm or otherwise explain if the organization and planning phase of the project is now complete.

88.2 Please explain any expected delays to the project schedule that have been identified at present.

89.0 **Reference: RATE BASE**
Exhibit B-1-1, p. 64; Exhibit B-5, BCUC IR 42; Attachment 1.42a, p. 3
GIS - costs

In its response to BCUC IR 42.1, PNG(NE) states:

> PNG-West and PNG(NE) (collectively, PNG, in response to this series 42 of questions) are currently defining the organization and planning the implementation of this project. At this time, PNG has identified the major tasks and timeline for the first phase of the project (Phase One) that will implement a useful GIS having a subset of the ultimate data and functionality that will be delivered over the three-year span of the overall

> project. Included is a task to identify, acquire and migrate spatial data related to the scope of work that will be defined for Phase One. PNG anticipates undertaking a competitive bid process for this part of the project.

On page 3 of the Attachment 1.42a (GIS Business Case), PNG(NE) states that the scope of the GIS project includes, "establishing the resources to provide ongoing maintenance and support."

On page 8 of the GIS Business Case, PNG(NE) states that:

> PNG adopts AUI's established GIS as the platform for its own implementation. PNG's GIS server applications will be hosted on servers located in AUI's offices, and maintained by AUI. PNG's GIS implementation will be completely aligned with the configuration in place at AUI. This will allow PNG to adopt existing applications and reports that AUI has developed, and to benefit from configuration-specific expertise at AUI for the support of PNG's GIS services and applications.

In its response to BCUC IR 42.7 and in Table 1 of Attachment 1.42a, PNG(NE) provides a cost estimate for the GIS Project. Further, in its response to BCUC IR 42.6, PNG(NE) states that "PNG has defined the organization and is currently developing a more detailed implementation plan for this project. This work is being completed by PNG's project manager, who is an employee of PNG, with the support of a GIS consultant, PNG's Engineering/Drafting group, and AUI's GIS Department."

On page 14 of the GIS Business Case, PNG(NE) states that subsequent phases will be defined during the completion of Phase One.

89.1 Please expand the table provided in response to BCUC IR 42.7 to categorize the component costs by operating, maintenance, administrative and capital costs, and by BCUC account for each of 2018, 2019 and 2020. Please ensure that the total costs for each year agrees to the totals in the table provided in response to BCUC IR 42.7.

89.2 Please provide a breakdown by year of the project costs associated with internal labour, third party consultant costs and other resources (i.e. SVG, Esri Canada).

89.3 Please provide a summary of costs that have been incurred prior to Test Year 2018 related to the GIS Project broken down by cost category (i.e. operating, maintenance, administrative and capital) and year.

89.4 Please identify the operating expenses that are ongoing or recurring costs related to the GIS Project for Test Years 2018 and 2019.

89.5 Please discuss if PNG(NE) is currently on budget with the GIS Project. If there is a revised cost estimate, please provide this including a breakdown of the costs.

89.6 Given that phases subsequent to phase one will be defined during the completion of phase one, please discuss the probability that the project cost estimate will change.

90.0 **Reference: RATE BASE**
Exhibit B-1-1, p. 64; Exhibit B-5, BCUC IR 1, 42.4;
Attachment 1.42a, p. 13 and Attachment A3
GIS – revenue requirements and rates

In its response to BCUC IR 42.4, PNG(NE) states that it, "has also provided a detailed cost estimate for the implementation, along with a forecast impact on customer rates, and details of its project governance and implementation plans."

On page 13 of the GIS Business Case, PNG(NE) further states:

> An analysis of the impact on the revenue requirement, and customer rates, was completed. The analysis was carried out at current regulatory rates of return, a depreciation rate of 10 percent, using a discount rate set to the nominal after tax weighted average cost of capital, and an inflation rate of 2%. The project impact on the revenue requirement was determined over 13 years, consisting of the three year implementation and 10 year post-implementation period. The initial capital costs, net present value ("NPV") of the impact to the revenue requirement and the one time equivalent rate impact is summarized in Table 6, below. The complete analysis for each of PNG-West, PNG(NE) FSJ/DC and PNG(NE) TR is provided in Appendix A3.

90.1 Please provide a working excel model with the NPV Analysis provided in Appendix A3.

90.2 Please provide a justification for the selected 10 percent depreciation rates for the GIS project capital costs.

90.3 Please justify the 13-year term selected for the NPV analysis, specifically the 10-year post-implementation period.

90.4 The NPV Analysis includes a line item for "AUI Support" under operating costs. Please elaborate on the support that will be provided in relation to these costs and explain why this isn't provided as part of the services already recovered through the inter-affiliate charge.

90.5 The NPV Analysis included in Appendix A3 does not include any operating cost reductions related to the GIS Project. Please discuss if there are any expected reductions in operating and maintenance costs or any other quantifiable financial benefits associated with the GIS Project that should be included in the NPV analysis. If so, please quantify by category and provide a revised NPV analysis.

91.0 **Reference: RATE BASE**
Exhibit B-1-1, Section 2.13, p. 69, BCUC IR 1, 44.0
Non-recurring capital expenditures – Baldonnel line lowering

In response to BCUC IR 44.1, PNG(NE) states:

> A privately owned sewage lagoon immediately adjacent to and encroaching upon the PNG(NE) right of way has breached on several occasions, resulting in super saturation of the soils supporting the PNG(NE) high pressure pipeline and geotechnical failures that have potential to impact the pipeline and result in integrity concerns related to stress and strain as a result of shifting pipeline bedding and cover. A geotechnical investigation complete with borehole drilling must be completed in order to determine necessary and feasible lowering and relocation options.

91.1 Please elaborate on the risk assessment undertaken to evaluate the impact of the geotechnical failures on the integrity of the pipeline.

91.2 Please elaborate on the anticipated scope of works. In your response please explain and provide details on whether the work will entail repair works or pipe replacement works on a 'like for like' basis.

91.3 Please elaborate on the relocation options, providing information on possible permitting or consultation requirements.

In response to BCUC IR 44.2, PNG(NE) states that it "will make a determination and seek approval for the remainder of the project, either in the next RRA or through a separate application, should it be considered necessary."

91.4 Please explain under what circumstances PNG(NE) will seek approval for the remainder of the project as part of a separate application.

92.0 **Reference:** **RATE BASE**
Exhibit B-1-1, Section 2.13, pp. 61 and 69, BCUC IR 45.0
Non-recurring capital expenditures – steel main replacements

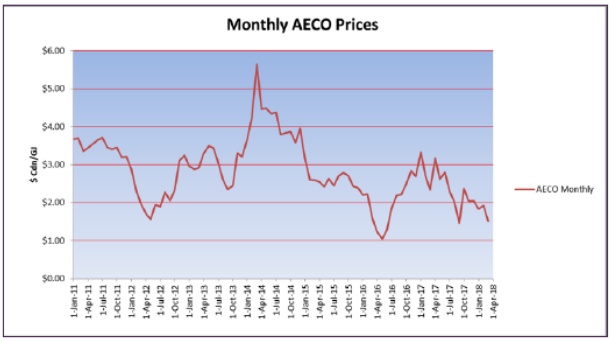
On pages 61 and 69 of the Amended Application, PNG(NE) forecast Total Capital Expenditure excluding overhead of $158,245 and $156,068 for Steel Main Replacement in Test Years 2018 and 2019 respectively.

92.1 Please provide a schedule for phase one of the Steel Main Replacement project for Test Years 2018 and 2019.

H. CAPITAL STRUCTURE AND RETURN ON CAPITAL

93.0 **Reference:** **BUSINESS RISK ASSESSMENT**
Exhibit B-5, BCUC IR 50.2.1; Exhibit B-1-1, Appendix F
Business risk assessment – market price volatility

In response to BCUC IR 50.2.1 regarding PNG(NE)'s assertion that "market prices have shown less volatility in recent years". PNG(NE) provided graphs showing the Monthly AECO prices and Station 2 daily prices, since 2011.



93.1 PNG(NE) showed the raw data of AECO monthly and Station 2 daily prices as noted above. Please provide further analysis to support PNG(NE)'s assertion that "market prices have shown less volatility in recent years." For example, did PNG(NE) compare any standard deviations, minimum/maximum range, or relied on any volatility index for natural gas prices?

93.2 Please discuss the impact of PNG(NE)'s cost portfolio resulting from the spikes in AECO and Station 2 market prices around January 2014, and confirm that PNG(NE)'s annual contracting plan has mechanisms in place to mitigate such market events.

94.0 **Reference:** **BUSINESS RISK ASSESSMENT**
Exhibit B-5, BCUC IR 50.3; Exhibit B-1-1, Appendix F
Business risk assessment – customer growth

In response to BCUC IR 50.3, PNG(NE) states:

> The FSJ/DC service area experienced approximately 2% growth for the period 2010 to 2016, but a slowdown in 2017.

94.1 Please provide the average customer growth rates of each year by rate class for the period from 2010 to 2017.

94.1.1 What is the average customer growth for the period 2010 to 2017?

94.1.2 Please explain why PNG(NE) experienced lower customer growth in 2017. Discuss PNG(NE)'s outlook for future customer growth.

I. IDENTIFIED SERVICE QUALITY METRICS

95.0 **Reference: IDENTIFIED SERVICE QUALITY METRICS**
Exhibit B-5, BCUC IR 55.1
Key service quality metrics

In response to BCUC IR 55.1, PNG(NE) states:

> PNG(NE) is a member of the Canadian Gas Association and compares its quality service metrics to those of other utilities across Canada, where applicable. Each utility has its own unique influences that affect their metrics. For example, PNG(NE) is one of the smallest utilities and is spread over a very large geographical area and this influences response times to customers in remote areas. A larger utility may have many resources in a heavily populated area, which may provide a different impact on response times. PNG(NE) monitors the metrics regularly for change and then address accordingly. The Lost-time Injury Frequency Rate is also a key metric that has benchmarking with the Canadian Gas Association.

95.1 Please provide a high level discussion of how PNG(NE) compares to other comparable utilities within the Canadian Gas Association with respect to the key service quality metrics provided in the Amended Application.

J. OTHER MATTERS TO BE ADDRESSED FROM PRIOR YEAR DECISIONS

96.0 **Reference: OTHER MATTERS TO BE ADDRESSED FROM PRIOR YEAR DECISIONS**
Exhibit B-1-1, Appendix B, pp. 5-6; Exhibit B-5, BCUC IR 56.0 – 56.17
Unaccounted for gas – unbilled days of service estimates

In response to BCUC IR 56.4, PNG(NE) states:

> The residential and small commercial unbilled estimates is based on a third order linear relationship between a representative customer's daily average consumption and the ambient temperature characterized by the daily heating degree day value over a calendar month:

$$\begin{aligned} &\textit{Daily Average Consumption (GJ)} \\ &\quad = Baseload + Heatload_1 \times HDD(18)_{Avg} + Heatload_2 \times HDD(18)^2 + Heatload_3 \times HDD(18)^3 \end{aligned}$$

Where:

Baseload	*= the per-customer, average daily gas consumption in GJ.*
$Heatload_{1,2,3}$	*= the first, second and third order factors determining the heat sensitive portion of a customer's daily gas consumption in GJ.*
$HDD(18)_{avg}$	*= Average daily heating degree day for the calendar month (i.e. The total heating degree days for the calendar month divided by the number of days in the month.)*

96.1 Please discuss PNG(NE)'s definition of a 'representative customer'.

96.2 What criteria does PNG(NE) use to obtain a representative of a customer's daily average consumption? Does the per customer average daily gas consumption include consumption from a basket including both core and transportation customer? Please discuss.

96.2.1 Over what time period is customer consumption averaged and why? Please explain.

96.2.2 Please confirm, or explain otherwise, that the daily average consumption is calculated separately for residential and small commercial customers.

96.3 How does the heat sensitive portion of a customer's daily gas consumption change if the customer is residential or small commercial? Please elaborate.

96.4 Please discuss how PNG(NE) utilizes temperature correction factors to determine the volume of gas delivered.

96.5 Please discuss how PNG(NE) uses pressure adjustment factors to determine the volume of gas delivered.

In response to BCUC IR 56.7, PNG(NE) states:

> PNG(NE) tracks unbilled DOS which are the number of days between the last date on which a customer's meter is read, and the end of the current calendar month. With the exception of a handful of larger customers, meters are read, and customers are subsequently billed, on a bi-monthly basis. Those customers whose meters have been read on a day during the current calendar month are referred to as "OnCycle" customers, and the unbilled DOS as OnCycle unbilled DOS. Customers whose meters are not read during the current calendar month are referred to as "OffCycle" customers.

In response to BCUC IR 56.13, PNG(NE) states:

> PNG(NE) has a number of processes in place to ensure that customers' meter readings have been accurately recorded and applied to the billing process. All gas meters used for billing customers are subject to inspection and verification procedures specified and reviewed by Measurement Canada.

In response to BCUC IR 56.7.2, PNG(NE) states that: "The change in DOS reporting only affected residential customers."

PNG(NE) further provides the following tables:

Fort St. John

TERM1 February Adjustment (Accrual for unbilled of OnCycle customers in current month):

Estimated reduction in OnCycle Customers due to reclassification of Offcycle Budget Customers =	A	(1,561)
Estimated average unbilled DOS of Offcycle Budget Customers =	B	53.84
Reduction in OnCycle unbilled DOS =	C = A x B	(84,010)
Reduction in OnCycle Unbilled Accrual (GJ) =	D = C x 0.384 GJ per mo[1]	(32,257)

TERM2 February Adjustment (Accrual for unbilled of OffCycle customers in current month):

Estimated increase in OffCycle Customers =	E = A	1,561
Estimated average unbilled DOS of Offcycle Budget Customers during February =	F	29
Increase in OffCycle DOS in February =	G = E x F	42,255
Increase in OffCycle Unbilled Accrual (GJ) =	H = G x 0.369 GJ per mo[2]	16,683

Dawson Creek

TERM1 February Adjustment (Accrual for unbilled of OnCycle customers in current month):

Estimated reduction in OnCycle Customers due to reclassification of Offcycle Budget Customers =	A	(1,076)
Estimated average unbilled DOS of Offcycle Budget Customers =	B	53.97
Reduction in OnCycle unbilled DOS =	C = A x B	(58,088)
Reduction in OnCycle Unbilled Accrual (GJ) =	D = C x 0.373 GJ per mo[1]	(21,658)

TERM2 February Adjustment (Accrual for unbilled of OffCycle customers in current month):

Estimated increase in OffCycle Customers =	E = A	1,076
Estimated average unbilled DOS of Offcycle Budget Customers during February =	F	29
Increase in OffCycle DOS in February =	G = E x F	31,211
Increase in OffCycle Unbilled Accrual (GJ) =	H = G x 0.359 GJ per mo[2]	11,204

96.6 How does PNG(NE) calculate gas consumption and subsequently bill non-residential customers? Please explain.

96.7 How many large customers does PNG(NE) supply where the meter reading and billing is not performed on a bi-monthly basis? Please provide this data for each service area.

96.7.1 How does PNG(NE) carry out meter reading and billing for these customers, and how frequently is this process carried out? Please explain.

96.7.2 Please provide the gas volume associated with these customers for the period January 2016 to December 2017.

96.8 What is meant by 'gas meters used for billing customers'? Are these meters only used for a certain subset of PNG(NE)'s customers? Please explain.

96.8.1 Do gas meters for these customers differ from those customers where the meter is read, and subsequently billed on a bi-monthly basis? How does PNG(NE) ensure accurate meter reading for these customers? Please elaborate.

96.8.2 Are these meters subject to inspection and verification procedures specified and reviewed by Measurement Canada? Please discuss.

96.9 What was the rationale for PNG(NE) implementing the change to the way unbilled days of service (DOS) were reported in February 2016? Please explain.

96.10 Please confirm, or otherwise explain, that the UAF volume adjustment made by implementing changes in February 2016 were exclusively as a result of customer reclassification.

96.10.1 Please explain why 1,561 FSJ customers were reclassified from OnCycle to OffCycle customers in February 2016.

96.10.2 Please explain why 1,076 DC customers were reclassified from OnCycle to OffCycle customers in February 2016.

96.10.3 Was this reclassification isolated to February 2016? If so, please explain why this was the only occurrence of reclassification. If not, please provide detail of other instances when PNG(NE) has reclassified customers.

96.10.4 Please identify and provide the excerpt from PNG's Terms and Conditions related to customer reclassification.

96.11 Please explain why the change in the reporting of OnCycle and Offcycle unbilled DOS only affected residential customers.

96.11.1 Why were no small commercial customers or other customers affected by this change? Please explain.

97.0 **Reference: OTHER MATTERS TO BE ADDRESSED FROM PRIOR YEAR DECISIONS**
Exhibit B-1-1, Appendix B, pp. 3–9; Exhibit B-5, BCUC IR 55.2–56.17 BCOAPO IR 3.1
Unaccounted for gas

In response to BCUC IR 56.1 PNG(NE) states: "Utility or third party activities include construction or excavation activity in proximity to PNG(NE)'s buried pipe which raise the potential for damage and with that the possible resultant loss of gas."

97.1 How is third party construction and excavation activity in proximity to pipelines coordinated with PNG(NE)? Please discuss.

In response to BCUC IR 56.2, PNG(NE) states:

> Electronic flow metering (EFM) is installed at all of PNG(NE)'s interconnections with Westcoast T-North, at connections receiving gas supply from producers at Stoddard and Wonowon in the Fort St. John delivery area, and Tomslake in the Dawson Creek delivery area, and at a handful of larger customers. All EFMs are checked and calibrated on a monthly basis in accordance with Measurement Canada requirements.

In response to BCUC IR 56.5, PNG(NE) states:

> The UAF volume is determined by subtracting the sum of all metered and unbilled consumption, changes in line pack, and estimates of known gas losses over a calendar month, from metered deliveries over the same period that are received onto Fort St. John and Dawsons Creek Systems.

97.2 What are the main causes of Electronic Flow Metering (EFM) measurement inaccuracies? Please elaborate.

97.3 Please explain how changes in line-pack can influence the determination of UAF volumes.

97.4 How does PNG(NE) estimate volumes of known gas losses over a calendar month? What are the main causes of known gas losses? Please discuss.

97.4.1 Please provide monthly volume estimates of known gas losses, attributing losses to those causes identified in response to the preceding IR, for the period January 2016 to December 2017.

In Directive 4 of Order G-105-17, it is stated that:

> PNG (N.E.) is directed to file a status report for the Gas Cost Variance Account (GCVA) by April 30th of each year showing the closing balance and the actual gigajoule amounts and costs/recoveries recorded in the GCVA for the previous calendar year with separate line entries for commodity purchases and sales, Company Use quantities, UAF losses and gains up to the percentage approved in the applicable RRA decision, and the UAF gains and losses over the percentage approved in the applicable RRA decision. The 2016 GCVA status report should be filed with the next PNG (N.E.) RRA.

97.5 Please provide a copy of the 2016 GCVA status report, with a breakdown by month. Please clearly demonstrate how the UAF amounts (or percentages) are calculated.

97.5.1 If the above status report does not include any of the months between January 2016 to January 2017 please provide details for the missing months in the same format as the 2016 GCVA status report.

On February 24, 2017, PNG(NE) filed an application for approval of the 2016 UAF Loss above 1.5 percent (2016-UAF Loss). PNG(NE) states:

> PNG further notes that large monthly UAF volumes were also recorded in the northeast on the PNG(NE) Fort St. John and Dawson Creek systems during December 2016. These results suggest that a cause may be found in the processes and reports common to all three systems…Depending on its findings, PNG may initiate a field review of its measurement facilities at its large customer sites and at Spectra's custody transfer meter facilities delivering gas onto the PNG-West, Fort St. John and Dawson Creek systems. The focus of this review would be to verify the appropriateness and correctness of the field equipment, equipment configurations and volume calculations.

In response to British Columbia Old Age Pensioners Organization *et al.* (BCOAPO) IR 3.1, PNG(NE) states:

> Additional drivers of the month-to-month variation in UAF volumes are physical losses of gas and measurement errors, although these are generally not significant. Measurement errors are generally systemic, introducing a constant level of error and only contribute to the month-to-month variation in UAF volumes when the meters are recalibrated. On one or two occasions over the past few years, PNG(NE) has encountered errors in the statement of metered deliveries received from Enbridge.

On page 3 of Appendix B, PNG(NE) states:

> The running 12-month total UAF exceeded its historical range only during the period from December 2016 to January 2017. A reversal of these losses occurred over the following two months (February and March 2017) with the result that the running 12-month total UAF returned to within historical bounds...Notable also, is the increase in the running 12-month total UAF in February and March 2016. A similar trend was exhibited by the UAF on the PNG-West system.

97.6 Please explain why PNG(NE) first attributed the large December 2016 UAF volumes to processes and reports common to all three systems instead of a cold weather event. What analysis did PNG(NE) undertake to ensure a cold weather event was the most likely cause of large UAF volumes?

97.7 How has PNG(NE) verified that the cause of UAF in February and March 2016 and again in December 2017 is not due to systemic measurement errors when large UAF was observed on all three systems (Fort St. John and Dawson Creek systems & PNG-West)? Please explain.

97.7.1 How can PNG(NE) ensure UAF losses observed in its Fort St. John and Dawson Creek systems are not attributed to processes or common reports? Please discuss.

97.8 Did PNG(NE) perform a field review of its measurement facilities at its large customer sites, as indicated in its February 24, 2017, 2016-UAF Loss Application? If yes, please provide this analysis. If not, why was this review not performed?

97.8.1 Please provide a breakdown of the costs associated with performing a field review of PNG(NE)'s measurement facilities.

97.9 Were any changes made to field equipment that could impact measurement of gas volumes? Please explain.

97.10 Please provide examples of issues that can arise with field equipment and configurations that could impact measurement of gas volumes, and measurement of UAF.

97.11 Please explain why the peak UAF volume, as a percentage of deliveries, occurred in January 2017, when the cold snap occurred in early December 2016? Specifically, please explain why a similar trend was not observed on the PNG-West system.

97.12 Please explain why there is a lag between the cold snap observed in December 2016 and when UAF, as a percentage of deliveries, falls to within historical bounds in February 2017.

97.13 Were meters recalibrated in these periods by PNG(NE) that could contribute to UAF volumes? Please elaborate.

97.14 Please provide detail on when PNG(NE) encountered errors in the statement of metered deliveries received from Enbridge. What were the volume errors as a percentage of total deliveries and UAF in these periods?

In response to BCUC IR 56.10, PNG(NE) states:

> PNG(NE) eliminated as probable causes, non-weather related effects in its analysis of the data and calculations associated with the determination of the UAF volume for December 2016. PNG(NE) then examined the daily temperatures experienced in its Fort St. John and Dawson Creek service areas during December and determined that average daily temperatures recorded by Environment Canada from December 7 to December 11, 2016 approached those expected to occur once in 50 years.

In response to BCUC IR 56.10.2 PNG(NE) states:

> PNG(NE) has completed a statistical analysis of weather patterns that occur in its delivery areas in order to determine the once-in-50-year temperatures that are used in load forecasts during system planning and gas supply procurement. Based on this analysis, PNG(NE) estimates the likelihood of a cold weather event, similar to the one observed during December, 2016 to be approximately once every 10 years.

97.15 Please explain how PNG(NE) determined the daily temperatures experienced in its Fort St. John and Dawson Creek service areas from December 7 to December 11, 2016 approached those expected to occur once in 50 years in BCUC IR 56.10 and once every 10 years in BCUC IR 56.10.2.

97.16 Please explain why PNG(NE) did not experience a reversal of the UAF losses in February and March 2016. Please provide a detailed explanation for each loss event that experienced large UAF losses with reference to the stated reason for the UAF loss (i.e. change in reporting, cold snap).

In response to BCUC IR 56.14, PNG(NE) state:

> PNG has not completed an analysis related to the correlation between significant cold snaps, and monthly UAF volumes…PNG(NE) does not suggest that December 2016 was the first occurrence of a cold snap affecting the estimate of unbilled consumption and therefore the UAF volume recorded. It is likely that other such examples can be found.

97.17 Please explain why PNG(NE) has not historically observed UAF volumes comparable to those recorded in December 2016, if it is likely that other examples of cold snaps affecting estimated unbilled consumption and therefore the UAF volume can be found.

On page 9 of Appendix B, PNG(NE) states:

> The total 2016 UAF loss amounts to $385,448 before tax (i.e. 203,081 GJs times $1.898/GJ, which is the approved Company use gas commodity cost applied throughout 2016). The difference between the 1.5 percent UAF not requiring further Commission approval and the 5.3 percent actual UAF is 145,572 GJs which amounts to $276,296 before tax (i.e. 145,572 GJs times $1.898/GJ).

97.18 Please confirm, or otherwise explain, that the Company Use Rider rate effective January 1, 2018, includes the value of UAF losses over the 1.5 percent ($276,296).

97.18.1 Please provide the amount of the company use rate rider per GJ that relates to the 2016 UAF losses over 1.5 percent.

97.19 Please confirm the time period over which the 2016 UAF value above 1.5 percent ($276,296) is amortized into rates.