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Verlon G. Otto
Director, Regulatory Affairs

Via E-file

July 6, 2020

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

File No.: 4.2.7(2020)

Attention: Marija Tresoglavic
Acting Commission Secretary

Dear Ms. Tresoglavic:

Re: Pacific Northern Gas (N.E.) Ltd.
Fort St. John/Dawson Creek and Tumbler Ridge Divisions
2020-2021 Revenue Requirements Application
Applicant's Final Argument

Accompanying, please find the written Final Argument of Pacific Northern Gas (N.E.) Ltd. in the referenced proceeding.

Please direct any questions regarding the application to my attention.

Yours truly,

Original on file signed by:

Verlon G. Otto

Enclosure

PACIFIC NORTHERN GAS (N.E.) LTD.

APPLICATION
to the
BRITISH COLUMBIA UTILITIES COMMISSION

FOR APPROVAL OF THE
FORT ST. JOHN/DAWSON CREEK
AND
TUMBLER RIDGE DIVISION
2020-2021 REVENUE REQUIREMENTS

APPLICANT'S FINAL ARGUMENT

July 6, 2020

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1. INTRODUCTION

1. On November 29, 2019, Pacific Northern Gas (N.E.) Ltd. (PNG(NE)) filed its 2020-2021 Revenue Requirements Application (Application) with the British Columbia Utilities Commission (BCUC) seeking, among other things, approval of interim rates effective January 1, 2020 for the Fort St. John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) divisions (Exhibit B-1).

2. On December 18, 2019, the BCUC approved interim rates for PNG(NE) effective January 1, 2020 under BCUC Order G-331-19 (Exhibit A-2) and established a regulatory timetable for the proceeding to review PNG(NE)'s Application. The order also included a directive for PNG(NE) to file an amended application on or before February 28, 2020 that would seek permanent rates effective January 1, 2020 and January 1, 2021.

3. The regulatory timetable established under Order G-331-19 provided for a written hearing process for the review of the Application and included provision for two rounds of information requests.

4. One party, British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, Tenants Resource and Advisory Center and Together Against Poverty Society, known collectively as BCOAPO et al. (BCOAPO), registered as an Intervener in the proceeding. One party, FortisBC Energy Inc., registered as an Interested Party in the proceeding.

5. On February 28, 2020, PNG(NE) filed an updated application (Amended Application) (Exhibit B-2) with the BCUC to, among other things:

(i) Provide actual results for 2019 under an additional column heading on the regulatory schedules in the Amended Application entitled Actual 2019;

(ii) Reflect the impact of Actual 2019 year-end balances on the January 1, 2020 opening balances and the resulting adjustments to the forecast 2020 and 2021 cost of service;

(iii) Adjust the 2020 and 2021 gas requirements forecasts having regard to actual deliveries in 2019, customer counts at the end of 2019, and the impact of 2019 actual amounts on the determination of the projected 2020 and 2021 use per account figures for residential and small commercial customers; and

(iv) Reflect a number of adjustments for known updates to estimates, including economic indicators, pension and non-pension expenses and certain capital projects.

6. Two rounds of information requests on the Amended Application were issued by the BCUC to PNG(NE). Responses were filed by PNG(NE) on April 29, 2020 (Exhibits B-3 and B-4) and June 3, 2020 (Exhibits B-6 and B-6-1). The BCUC also issued a single confidential information request, which PNG(NE) responded to on June 3, 2020 (Exhibit B-6-1). PNG(NE) notes that it also submitted one evidentiary update on June 16, 2020 (Exhibit B-2-2) to address an identified error related to the calculation of income tax impacts of certain IT-related capital additions (see Section 15 of this submission).

7. Two rounds of information requests on the Amended Application were issued by the BCOAPO to PNG(NE). Responses to these information requests were filed by PNG(NE) on April 29, 2020 and June 3, 2020 (Exhibits B-5 and B-7, respectively).

8. On June 16, 2020, PNG(NE) wrote to the BCUC to advise that it had identified an error in the Amended Application that pertained to the modelling and calculation of the income tax impacts of certain IT-related capital additions in the test period under review.[1] Pursuant to Order G-159-20, the BCUC admitted PNG(NE)'s letter in the evidentiary record (Evidentiary Update) and established further process permitting the BCUC and the BCOAPO to submit information requests to PNG(NE) based upon the Evidentiary Update. On June 30, 2020, PNG(NE) responded to the BCUC information request on the Evidentiary Update (Exhibit B-8). The BCOAPO did not submit an information request on the Evidentiary Update.

9. The remainder of this submission will address the areas of the Amended Application that were the subject of information requests during the proceeding, and sets forth PNG(NE)'s

[1] Exhibit B-2-2

Final Argument in support of its Amended Application to the BCUC for approval of the FSJ/DC and TR 2020-2021 revenue requirements and resultant rates.

10. PNG(NE)'s reply submission, to be filed with the BCUC on July 6, 2020, will address any issues that may be raised by the Intervener in its final submission to be filed with the BCUC on June 26, 2020.

2. IMPACTS OF COVID-19 PANDEMIC

11. Top of mind throughout this proceeding, and continuing through to the time of preparing this submission, has been the COVID-19 pandemic and the potential for impacts to the forecasts underlying the Amended Application, including demand and operating and capital costs. In response to information requests,[2] PNG(NE) observed that it was closely monitoring the effects of COVID-19 on its customers and on its current and planned operating activities, and noted that a separate application had been made to the BCUC for the creation of a COVID-19 deferral account to capture unrecovered revenues and unplanned costs arising from the COVID-19 pandemic.[3]

12. As the proceeding advanced, PNG(NE) addressed specific impacts of COVID-19 on the amounts underlying the Amended Application, including:

i) Customer Demand: In response to BCUC IR 65.1.2 (Exhibit B-6) PNG(NE) indicated that it does not yet have evidence of any substantial impact to gas consumption as a result of COVID-19. PNG(NE) further noted in response to BCUC IR 65.3 (Exhibit B-6) that mechanisms are in place to capture use per account variances related to residential and small commercial customers and load variances for some industrial customers.

ii) Financing Costs: In response to BCOAPO IR 1.6 (Exhibit B-5) PNG(NE) observed that despite rate reductions in underlying government debt instruments, underlying rates for corporate instruments have not moved significantly, with financial institutions significantly increasing credit spread requirements and

[2] Exhibit B-5, BCOAPO IR 1's; Exhibit B-6, BCUC IR 65's and 82.3's; Exhibit B-7, BCOAPO IR 1's and 13.1

[3] Exhibit B-5, BCOAPO IR 1.2; Exhibit B-6, BCUC IR 65.3

standby charges for debt that have more than offset the reductions in prime rates. PNG(NE) observed that it has established deferral accounts in place to capture variances in short-term and long-term interest rates and that it will rely on these deferral accounts to capture any differences in financing costs that may arise for Test Years 2020 and 2021.

iii) Capital Expenditures: In response to BCUC IR 65.1.1 (Exhibit B-6), PNG(NE) advised that it does not anticipate the COVID-19 pandemic having a material impact on the timing of any IT projects or capital projects, and that it was not expecting any material impacts to the spend on capital programs.

iv) Return on Equity: In response to BCOAPO IR 1.9 (Exhibit B-5), PNG(NE) observed that while equity markets are highly volatile, it continues to be appropriate to use the return on equity and capital structure approved for 2018 and 2019 for Test Years 2020 and 2021. PNG(NE) further noted that attempting to determine a change to any utility's return on equity and capital structure during current volatile equity markets would not be appropriate.

13. Based on the foregoing, PNG(NE) does not believe that any significant revision to the Amended Application is warranted at this time as a result of the impacts of COVID-19.

3. BCUC APPROVALS SOUGHT

14. For the reasons set forth in this argument and in PNG(NE)'s filings for this proceeding, PNG(NE) respectfully requests BCUC approval of the following:

3.1 Fort St. John / Dawson Creek Division

(i) Approval, effective January 1, 2020, on a permanent basis pursuant to sections 58 to 61 of the *Utilities Commission Act*, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes presented in under Tab Schedules, Tab 6, page 8 in the table entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2020" as set forth under the heading "Rate Changes for Revenue Deficiency ($/GJ)", subject to adjustments and undertakings identified through the regulatory review process.

(ii) Approval, effective January 1, 2021, on a permanent basis pursuant to sections

58 to 61 of the *Utilities Commission Act*, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes presented under Tab Schedules, Tab 6, page 28 in the table entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2021" as set forth under the heading "Rate Changes for Revenue Deficiency ($/GJ)", subject to adjustments and undertakings identified through the regulatory review process.

(iii) Approval of PNG(NE)'s proposal per Section 1.3 of the Amended Application to utilize a short term interest bearing rate deferral account in 2020 to levelize the impact of the combined net revenue deficiencies for 2020 and 2021 to be fully amortized in 2021.

(iv) Approval of the changes and additions to PNG(NE)'s deferral accounts and amortization expenses for 2020 and 2021, pursuant to sections 58 to 61 of the *Utilities Commission Act*, as detailed in Section 2.10, Amortization of the Amended Application, and as shown in the Continuity of Deferred Charges tables set forth in this same exhibit under Tab Schedules, Tab 2, including approval to create the Accelerated CCA deferral account to record the impact of taking accelerated CCA in 2019 and amortizing this to the benefit of customers in Test Year 2020, as well as the subsequent dissolution of this account after Test Year 2021.

(v) Approval to create a new interest bearing deferral account to record the portion of Shared Corporate Services Costs not recovered in customer rates in Test Year 2020 nor Test Year 2021 for services received to be amortized at a future date further to BCUC approval as set forth in Section 2.5.8 of the Amended Application.

(vi) Approval of the shared services charges from PNG-West to PNG(NE) for 2020 and 2021, as set forth in Section 2.6 – Shared Services Cost Allocation of the Amended Application.

(vii) Approval to continue the unaccounted for gas volume deferral account to record the difference between forecast and actual unaccounted for gas (UAF) volumes in Test Year 2020 and 2021 based on using a 1.5 percent of deliveries UAF loss factor for 2020 and 2021 and requiring PNG(NE) to apply for BCUC approval to record actual 2020 or 2021 UAF losses above 1.5 percent in the deferral account.

(viii) Approval of the capital reporting process proposed by PNG(NE) in response to directive 5 of BCUC Order G-164-18A as set forth in Section 3.4.1.1 of the Amended Application, and as addressed in Section 16.1 of this submission.

(ix) Approval of the automotive cost allocation methodology proposed by PNG(NE) in response to a directive as per Section 3.0 of the BCUC's Reasons for Decision of Order G-164-18A as set forth in Section 3.4.1.4 of the Amended Application, and as addressed in Section 16.2 of this submission.

3.2 Tumbler Ridge Division

(i) Approval, effective January 1, 2020, on a permanent basis pursuant to sections 58 to 61 of the *Utilities Commission Act*, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes presented in under Tab Schedules, Tab 6, page 3 in the table entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2020" as set forth under the heading "Rate Changes for Revenue Deficiency ($/GJ)", subject to adjustments and undertakings identified through the regulatory review process.

(ii) Approval, effective January 1, 2021, on a permanent basis pursuant to sections 58 to 61 of the *Utilities Commission Act*, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes presented under Tab Schedules, Tab 6, page 14 in the table entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2021" as set forth under the heading "Rate Changes for Revenue Deficiency ($/GJ)", subject to adjustments and undertakings identified through the regulatory review process.

(iii) Approval of PNG(NE)'s proposal per Section 1.3 of the Amended Application to utilize a short term interest bearing rate deferral account in 2020 to levelize the impact of the combined net revenue deficiencies for 2020 and 2021 to be fully amortized in 2021.

(iv) Approval of the changes and additions to PNG(NE)'s deferral accounts and amortization expenses for 2020 and 2021, pursuant to sections 58 to 61 of the *Utilities Commission Act*, as detailed in Section 2.10, Amortization of the Amended Application, and as shown in the Continuity of Deferred Charges tables set forth in this same exhibit under Tab Schedules, Tab 2, including:

a) Approval to create the Accelerated CCA deferral account to record the impact of taking accelerated CCA in 2019 and amortizing this to the benefit of customers in Test Year 2020 as well as subsequent dissolution of this account after Test Year 2021; and

b) Approval to eliminate the Studies deferral account which was fully amortized in 2018.

(v) Approval to create a new interest bearing deferral account to record the portion of Shared Corporate Services Costs not recovered in customer rates in Test Year 2020 nor Test Year 2021 for services received to be amortized at a future date further to BCUC approval as set forth in Section 2.5.8 of the Amended Application.

(vi) Approval of the shared services charges from PNG-West to PNG(NE) for 2020 and 2021, as set forth in Section 2.6 – Shared Services Cost Allocation of the Amended Application.

(vii) Approval to continue the unaccounted for gas (UAF) volume deferral account on the basis, pursuant to sections 58 to 61 of the *Utilities Commission Act* that the UAF volume forecast for Test Year 2020 and Test Year 2021 are set at zero with PNG(NE) recording the variance between zero percent and a loss of up to 1.0 percent without having to seek further BCUC approval. PNG(NE) would be required to file an application with the BCUC to obtain approval to record UAF losses above 1.0 percent in this deferral account.

(viii) Approval of the capital reporting process proposed by PNG(NE) in response to directive 5 of BCUC Order G-164-18A as set forth in Section 3.4.1.1 of the Amended Application, and as addressed in Section 16.1 of this submission.

(ix) Approval of the automotive cost allocation methodology proposed by PNG(NE) in response to a directive as per Section 3.0 of the BCUC's Reasons for Decision of Order G-164-18A as set forth in Section 3.4.1.4 of the Amended Application, and as addressed in Section 16.2 of this submission.

4. COST OF SERVICE

15. PNG(NE) recognizes that increases in the delivered cost of gas impacts its customers. PNG(NE) has responded by taking reasonable and prudent measures to control its costs and submits that the costs included in PNG(NE)'s applied for cost of service for 2020 and 2021 are necessary and reasonable and reflect the requirements to operate PNG(NE)'s system in a safe and reliable manner. PNG(NE) further submits that its forecast costs of service are prudently incurred, normal course business expenses that should be fully recoverable from ratepayers.

16. As described further in Section 6 of this submission, a number of adjustments and corrections to forecast data were identified in the course of this proceeding. These adjustments and corrections impact the cost of service for 2020 and 2021 and are summarized in a table provided in Section 6 of this submission. While PNG(NE) has proposed to reflect these impacts in the final regulatory schedules, this submission generally addresses amounts as represented in the Amended Application, noting proposed adjustments and corrections, as necessary.

4.1 Fort St. John / Dawson Creek Division

17. In PNG(NE)'s Amended Application, the Test Year 2020 cost of service of $18.885 million (excluding company use gas costs) has increased by $1.288 million compared to $17.598 million approved for Decision 2019. In addition, the Amended Application has forecast 2020 to have a revenue deficiency of $1.643 million after provision for the rate deferral mechanism described in Section 5 of this submission, primarily attributable to:

i) An overall increase in operating and maintenance and administrative and general costs of $0.9 million primarily due to planned activities to ensure compliance with pipeline integrity related code, standards and regulations and address aging infrastructure concerns, additional resources in field operations, as well as increased general and administrative costs for a replacement financial system and human resources information system;

ii) A margin decrease of $0.7 million mostly due to the loss of a significant small industrial customer as well as continuing decreasing trend in Use per Account;

iii) Higher amortization expense of $0.3 million resulting from the amortization of the ICCDA deferral due to the loss of a small industrial customer in 2019, as well as the recording of the second-year provision of the transition to negative salvage

accounting offsetting the credit amortization of the accelerated CCA taken in 2019 and the effect of the 2019 rate smoothing deferral amortization; and

iv) Higher depreciation expense, property tax expense and return on rate base totalling $0.3 million reflecting increased capital investment in PNG(NE).

18. The adverse impacts of the above factors have been partially offset by:

i) Lower income taxes of $0.2 million primarily due to the application of accelerated CCA in Test Year 2020; and

ii) A decrease of $0.5 million to reflect PNG(NE)'s proposal to utilize the rate smoothing deferral account to levelize the impact of the combined forecast increases for Test Year 2020 and Test Year 2021 on customer rates over these two years.

19. Further, as per the Amended Application, the forecast Test Year 2021 cost of service of $20.044 million (excluding company use gas costs) was $1.159 million greater than that for Test Year 2020. In addition, the Amended Application has forecast 2021 to have a revenue deficiency of $1.792 million after provision for the rate deferral mechanism described in Section 5 of this submission, primarily attributable to:

i) Higher depreciation expense, property tax expense and return on rate base totalling $0.8 million reflecting increased capital investment in PNG(NE);

ii) Higher income taxes of $0.3 million primarily due to the higher return on equity from increased rate base in Test Year 2021 as well as timing differences;

iii) $0.7 million related to PNG(NE)'s proposal to utilize the rate smoothing deferral account to levelize the impact of the combined forecast increases for Test Year 2020 and Test Year 2021 on customer rates over these two years; and

iv) $0.1 million from lower overheads capitalized of $0.1 million due to less capital programs in Test Year 2021 compared to Test Year 2020 and a slight increase in operating, maintenance, and administrative and general expenses.

20. The adverse impacts of the above factors have been partially offset by lower net amortization of deferred charges of $0.1 million mainly due to there being no debit ICDDA amortization forecast for Test Year 2021 compared to Test Year 2020, offset by the recording of the third year provision of the transition to negative salvage accounting.

4.2 Tumbler Ridge Division

21. In PNG(NE)'s Amended Application, the Test Year 2020 cost of service of $1.956 million (excluding company use gas costs) has increased by $0.174 million compared to $1.782 million approved for Decision 2019. In addition, the Amended Application has forecast 2020 to have a revenue deficiency of $56,000 after provision for the rate deferral mechanism described in Section 5 of this submission, primarily attributable to:

i) Higher operating, maintenance and administrative and general expenses of $157,000 or 12.6% compared to Decision 2019 primarily due to an increase in planned activities to ensure compliance with pipeline integrity related codes, standards and regulations and address aging infrastructure concerns which include planned investigative digs based on the latest close Interval Survey work and increased plant maintenance and plant turnaround activities, as well as increase in general and administrative costs mainly from an allocation of costs for a replacement financial system and human resources information system and higher pension expense;

ii) Higher depreciation expense, property tax expense and return on rate base totalling $75,000 reflecting the increased capital investments in PNG(NE), including processing plant improvements and repairs to the Tumbler Ridge transmission pipeline;

iii) Higher amortization expense of $42,000 in Test Year 2020 due primarily to the amortization of the Industrial Customers Deliveries Deferral Account (ICDDA) as the net combined 2018 and 2019 deliveries to its only industrial customer were lower than forecast, as well as the recording of the second year of transition to negative salvage accounting; and

iv) An increase of $53,000 for PNG(NE)'s proposal to levelize the impact of the combined forecast increases for Test Year 2020 and Test Year 2021 on customer rates over these two years.

22. The adverse impacts of the above factors have been partially offset by:

i) Higher forecast margins of $171,000 primarily due to higher forecast deliveries in 2020 to PNG(NE)'s only industrial customer;

ii) $53,000 for PNG(NE)'s rate smoothing the impact of the combined forecast increases on customer rates over 2018 and 2019; and

iii) Higher transfers to capital of $31,000 due to increased capital programs.

23. Further, as per the Amended Application, the forecast Test Year 2021 cost of service of $2.139 million (excluding company use gas costs) was $0.183 million greater than that for Test Year 2020. In addition, the Amended Application has forecast 2021 to have a revenue deficiency of $63,000 after provision for the rate deferral mechanism described in Section 5 of this submission, primarily attributable to:

i) Net impact of approximately $54,000 due to increasing capital investment in PNG(NE) which results in higher depreciation expense, higher return on equity and financing costs;

ii) Higher income taxes of $35,000 mainly due to a reduction in timing differences as well as higher return on equity;

iii) Net higher operating and maintenance and administrative and general costs of $41,000, resulting mainly from costs for increasing number of meter recalls required in Test Year 2021 as well as inflationary increases;

iv) Net higher amortization expense of $42,000 mainly to reflect the third year of transitioning to negative salvage accounting, and the loss of the accelerated CCA amortization and offset by no debit amortization of ICDDA in Test Year 2021; and

v) Lower transfers to capital due to less capital projects in Test Year 2021.

24. The adverse impacts of the above factors have been partially offset by:

i) Higher forecast margins of $12,000 mainly due to a forecast minor increase in use per account for residential and small commercial customers; and

ii) $108,000 related to PNG(NE)'s proposal to levelize the impact of the combined forecast increases for Test Year 2020 and Test Year 2021 on customer rates over these two years.

5. RATE DEFERRAL MECHANISM

25. PNG(NE) is seeking approval for permanent changes to the delivery charge component of its customer rates in order to recover its cost of service for both 2020 and 2021.

26. For FSJ/DC, the revenue deficiency of $1.973 million for 2020 and the revenue

deficiency of $1.118 million for 2021 forecast in the Amended Application would necessitate a residential delivery rate increase of approximately 14% in 2020 and a subsequent rate increase of approximately 7% in 2021, with a cumulative total revenue deficiency of $3.091 million for the two-year period. For TR, the revenue deficiency of $3,000 for 2020 and the revenue deficiency of $171,000 for 2021 forecast in the Amended Application would necessitate a residential delivery rate increase of 0.1% in 2020 and a subsequent rate increase of 9.9% in 2019, with a cumulative total revenue deficiency of $174,000 for the two-year period.

27. Similar to the 2018-2019 revenue requirements application, to provide customers with rate stability by reducing rate volatility, PNG(NE) has again proposed a rate deferral mechanism such that the full impact of the combined rate changes anticipated from the cumulative revenue deficiencies for 2020 and 2021 of $3.091 million for FSJ/DC and of $0.174 million for TR would be levelized over the two-year test period.[4]

28. As noted in the Amended Application, for FSJ/DC this would be achieved by recording $0.330 million of the 2020 anticipated revenue deficiency in an interest bearing deferral account in 2020 and amortizing and applying it to the anticipated revenue deficiency for 2021. By making this provision for FSJ/DC, 2020 would have a calculated revenue deficiency of $1.643 million and 2021 would have a calculated revenue deficiency of $1.792 million, which would result in an increase to the delivery rate component of residential customer rates of approximately 11% for each of 2020 and 2021.

29. For TR, this would be achieved by recording $53,000 of the anticipated 2021 revenue deficiency in an interest bearing deferral account in 2020 and amortizing and applying it to the anticipated revenue deficiency for 2021. By making this provision for TR, 2020 would have a calculated revenue deficiency of $56,000 and 2021 would have a calculated revenue deficiency of $63,000, which would result in an increase to the delivery rate component of residential customer rates of approximately 3% for each of 2020 and 2021, respectively.

30. PNG(NE) hereby submits that, subject to rebalancing to accommodate the adjustments and corrections noted in Section 6, the proposed rate deferral mechanism should be approved as applied for as a means to provide customers with rate stability by reducing

[4] Exhibit B-2, Section 1.3

volatility in rates that would otherwise be determined.

6. SUMMARY OF ADJUSTMENTS/CORRECTIONS TO FINAL REGULATORY SCHEDULES

31. PNG(NE) notes that during the course of this proceeding and in responding to information requests a number of adjustments and corrections to forecast data were identified that PNG(NE) proposed to reflect in the final regulatory schedules. In addition, PNG(NE) identified an error related to the calculation of income tax impacts of certain IT-related capital additions, as described in Section 15 of this submission, and has proposed to correct for this in the final regulatory schedules as well.

32. PNG(NE) has summarized proposed adjustments and corrections in the tables that follow for both FSJ/DC and TR.

Summary of Adjustments / Corrections – FSJ/DC

Reference	Addressed in Section	Subject	Type of Adjustment	2020 Impact on Revenue Deficiency	2021 Impact on Revenue Deficiency
FSJ/DC & TR BCUC IR 9.2	8.6	BCUC 685 Utility Costs	Correction of budget error	(11,000)	-
FSJ/DC & TR BCUC IR 30.1	16.1.3	Distribution Mains / Steel Mains Replacement CAPEX	Reclassification of capital from BCUC 475 Distribution Mains to BCUC 465 Steel Main Replacement:	(3,000)	(1,000)
FSJ/DC & TR BCUC IR 32.1	8.3 / 16.1.1.4	AMR Capital Costs	Update for capital costs to tie in to CPCN Application	(6,000)	25,000
FSJ/DC & TR IR BCUC 57.1	8.6	BCUC 670 Contractor Costs	Update for Janitorial, Mats, Garbage, Copier costs	20,000	1,000
FSJ/DC & TR BCUC IR 68.4	8.1 / 16.1.3	New BCOGC Requests	Add 2020 and 2021 O&M and capital for BCOGC costs.	17,000	38,000
FSJ/DC & TR BCUC IR 71.1	8.2	Temporary Labour	Remove temporary employee labour in O&M	(23,000)	(1,000)
FSJ/DC & TR BCUC IR 77.1	14.2.1.2	Shared Corporate Services Deferral Account Interest Rate	Change from short-term interest rate to WACD	-	-
Evidentiary Update (Exhibit B-2-2)	15	CCA Correction	CCA Class 12 software assets not added to UCC pool and not included in income tax calculation	(445,000)	61,000
Residual Impact	n/a	Transfers to Capital	Changes flowing through to PNG(NE) as a result of adjustments to PNG-West capital	30,000	(37,000)
Net Impact before Rate Deferral Mechanism Adjustment				**(421,000)**	**86,000**
		Rate Deferral Mechanism	Levelization over 2 years	193,000	(396,000)
Net Impact after Rate Deferral Mechanism Adjustment				**$ (228,000)**	**$ (310,000)**

Summary of Adjustments / Corrections – TR

Reference	Addressed in Section	Subject	Type of Adjustment	2020 Impact on Revenue Deficiency	2021 Impact on Revenue Deficiency
TR BCUC IR 2.1	8.6	CIS DCVG Costs	Reduce BCUC 665 Contractor Costs from competitive bid results	$ (35,000)	$ 35,000
FSJ/DC & TR BCUC IR 32.1	8.3 / 16.1.1.4	AMR Capital Costs	Update for capital costs to tie in to CPCN Application	-	-
FSJ/DC & TR BCUC IR 68.4	8.1 / 16.1.3	New BCOGC Requests	Add 2020 and 2021 O&M and capital for BCOGC costs.	1,000	1,000
FSJ/DC & TR BCUC IR 77.1	14.2.1.2	Shared Corporate Services Deferral Account Interest Rate	Change from short-term interest rate to WACD	-	-
Exhibit B-6 Cover Letter	16.1.2.1	Remove Extra Boiler Cost from Capital	Remove double counting of $61,200 of capital from 2020	(1,000)	(5,000)
Evidentiary Update (Exhibit B-2-2)	15	CCA Correction	CCA Class 12 software assets not added to UCC pool and not included in income tax calculation	(32,000)	5,000
Net Impact before Rate Deferral Mechanism Adjustment				**(67,000)**	**36,000**
		Rate Deferral Mechanism	Levelization over 2 years	36,000	(74,000)
Net Impact after Rate Deferral Mechanism Adjustment				**$ (31,000)**	**$ (38,000)**

33. For FSJ/DC, it is estimated that the adjustments proposed by PNG(NE) for 2020 and 2021 will result in a reduction to the forecast revenue deficiency for 2020, from $1.643 million as per the Amended Application to $1.415 million, and a decrease in the revenue deficiency for 2021 from $1.792 million as per the Amended Application to $1.482 million. For TR, it is estimated that the adjustments proposed by PNG(NE) for 2020 and 2021 will result in a reduction to the forecast revenue deficiency for 2020, from $56,000 as per the Amended Application to $25,000, and a decrease in the revenue deficiency for 2021 from $63,000 as per the Amended Application to $25,000.

34. These adjustments will have flow-through effects on the resultant rates for the test periods in comparison to those proposed in the Amended Application. PNG(NE) will reflect BCUC-approved adjustments in its final regulatory schedules.

7. DEMAND FORECAST, REVENUES AND MARGIN

35. PNG(NE) prepares forecasts of demand for its customers with the overall objective of being as accurate as possible having regard to information available at the time of developing the forecasts. PNG(NE) submits that the methodologies applied in forecasting customer demand produce reasonable results, and that the forecast demand for each customer classification for 2020 and 2021 are reasonable and should be approved as filed for rate making purposes.

7.1 Residential and Small Commercial Demand Forecast

36. As described in the Section 2.1, Demand Forecast, Revenue and Margin, of the Amended Application, the methodology applied by PNG(NE) for forecasting customer demand, including forecast customer counts and forecast Residential and Small Commercial Use per Account (UPA) for Test Year 2020 and Test Year 2021, is consistent with the methodology applied in prior years and approved by the BCUC. The BCUC had several information requests on PNG's Residential and Small Commercial demand forecast, primarily seeking explanations for forecast changes,[5] and also in the context of the forecasts included in the 2019 Consolidated Resource Plan concurrently under review by the BCUC,[6] to which PNG(NE) responded that harmonization of the short-range forecasting methodology applied for its revenue requirements applications and the long-range forecasting methodology applied for resource planning is not appropriate, nor is it necessary.[7]

7.2 Other Customer Demand Forecasts

37. Consistent with prior years, the projected deliveries for other customer classes are based on methodologies consistent with past practice as approved by the BCUC, and are primarily based on a review of historical deliveries and expected customer use for 2020 and 2021 as obtained from surveys and discussions with these customers.

38. PNG(NE) submits that the methodology applied for forecasting customer demand in the Amended Application produces appropriate and reasonable results that should be approved as filed.

8. OPERATING EXPENSES

39. PNG(NE) has provided a substantial amount of information in the Exhibits filed in this proceeding to support its forecast operating expenditures for 2020 and 2021. PNG(NE)'s Amended Application narrative on these expenditures was set forth in Section 2.3 of Exhibit B-2. PNG(NE)'s responses to information requests further elaborate on the rationale and basis

[5] Exhibit B-3, BCUC IR 1's
[6] Exhibit B-3, BCUC IR 2's
[7] Exhibit B-3, BCUC IR 2.2

for the forecast amounts.

40. Subject to adjustments and undertakings identified through the regulatory review process (see summaries provided in Section 6 of this submission), FSJ/DC gross operating expenses for 2020 are forecast to be $6.513 million which is $0.397 million or 6.5% greater compared to $6.115 million for Decision 2019, and $6.653 million for 2021, which is $140,000 or 2.2% greater compared to 2020. TR gross operating expenses for 2020 are forecast to be $894,000 which is $86,000 or 10.7% greater compared to $808,000 for Decision 2019, and $937,000 for 2021, which is $43,000 or 4.8% greater compared to 2020.

41. In addition to general inflationary pressures on costs, the following five factors have been identified as having a considerable impact on PNG(NE)'s cost of service for 2020 and 2021:

(i) Increase in operating costs due to increased activities relating to ensuring compliance with PNG(NE)'s integrity management plans and related codes, standards and regulations;

(ii) Provision for an additional two utility person full-time equivalent positions compared to positions incorporated into the 2019 costs;

(iii) Plans to update and replace the current manual meter reading process for residential and commercial customers with automated meter reading (AMR) infrastructure;

(iv) A joint project with PNG-West and its sister utilities, AUI and HGL, to implement a new CIS system to replace the existing legacy systems at the respective utilities; and

(v) Implementation of the proposed modification to the automotive cost allocation methodology resulting in a lower allocation of consolidated automotive costs to FSJ/DC and TR.

8.1 System Integrity Focus

42. In the Amended Application PNG(NE) identified that it will see a general increase in operating costs due to increased activities relating to safety and ensuring compliance with its integrity management plans and related codes, standards and regulations (i.e. CSA Z662-19,

Oil & Gas Activities Act, BC OGC/Technical Safety BC). Further, recent industry incidents, such as the Enbridge pipeline rupture and ignition near Prince George have highlighted the need to maintain compliance and to ensure leading risk management practices and activities. PNG(NE) submits that it monitors industry practices to support the goal of continued robustness to its integrity programs, and seeks to have a balance of internal expertise and third party contractors to achieve this goal in the face of ever more stringent codes, standards and regulations and related industry expectations.

43. In response to BCUC IRs 68.3 and 68.4, PNG(NE) addressed recent BCOGC notifications on requirements for pipeline risk assessment including aged pipeline condition assessment and IMP audits for which costs had not been incorporated into PNG(NE)'s Amended Application. The summary of adjustments presented in Section 6 of this submission incorporates PNG(NE)'s share of the consolidated costs proposed for inclusion in the final regulatory schedules.

44. In addition to information presented in the Amended Application, PNG(NE) submits that its planned integrity-focused operating activities and expenditures have been subject to a thorough examination via additional information provided in the responses provided to information requests in this proceeding and should be approved. [8]

8.2 Operations Field Staff Positions

45. PNG(NE) has always been very cautious and conscientious on the matter of adding new positions to its existing organizational structure. PNG(NE)'s Amended Application includes provision for two additional utility person full-time equivalent positions compared to positions incorporated into the Decision 2019 costs. PNG(NE) considers these positions to be necessary, primarily to meet increasing work requirements around operating and maintaining existing plant and infrastructure, and for the installation of new plant and infrastructure. PNG(NE) notes the importance of such roles for emergency response and critical utility functions, particularly in the face of the demographic challenges with an aging workforce.

46. PNG(NE) provided additional information on the proposed new utility person positions

[8] Exhibit B-3, BCUC IR 6's; Exhibit B-4, BCUC IR 2's; Exhibit B-6, BCUC IR 68's and 69's; Exhibit B-5, BCOAPO IR 2's; Exhibit B-7, BCOAPO IR 3's

in response to information requests.[9] As it pertains to the two additional positions, PNG(NE) notes that it will directionally decrease its reliance on temporary employees and contractors. In this regard, as noted in response to BCUC IR 71.1, PNG(NE) identified that costs associated with temporary employees were inadvertently included in 2020 and 2021. PNG(NE) has proposed to remove costs of $23,000 and $23,538 from 2020 and 2021, respectively, in the final regulatory schedules as reflected in Section 6 of this submission.

8.3 Implementation of Automated Meter Reading (AMR)

47. On March 25, 2020, PNG(NE) submitted an application to the BCUC for a Certificate of Public Convenience and Necessity (CPCN) to update and replace the current manual meter reading process for residential and commercial customers with automated meter reading (AMR) infrastructure. This application is concurrently under active review by the BCUC. In the Amended Application,[10] PNG(NE) noted that the AMR project has an estimated capital cost of $3.5 million and that it offers significant potential operating cost savings, including those associated with a workforce reduction of five meter reader positions for labour, benefit and equipment costs. In response to BCUC IR 32.1, PNG(NE) provided a reconciliation of AMR project costs per the Amended Application to those included in the CPCN application, noting that the costs per the CPCN application reflected an update to the $US/$CAD exchange rate, as well as an added provision under project management for quality assurance. PNG(NE) proposed reflecting an adjustment to these costs in the final regulatory schedules and has included this item in the summary of adjustments presented in Section 6 of this submission.

48. A number of information requests focused on whether the AMR project costs should be included in the Amended Application. PNG(NE) noted that it had planned to file the CPCN application at the same time as the Amended Application and therefore reflected both the expected capital costs of the AMR project in Test Year 2020, as well as the anticipated operating cost savings in Test Year 2021 in the Amended Application. PNG(NE) remains hopeful that approval of the AMR project will be granted prior to the filing of the compliance regulatory schedules in this proceeding, and in time to enable PNG(NE) to commence the project and install the new AMR infrastructure in 2020 given the benefits of the project to

[9] Exhibit B-3, BCUC IR 7's; Exhibit B-7, BCUC IR 71.1

[10] Exhibit B-2, Section 2.3 and Section 2.13.1.1.1

ratepayers, employees, and the environment. However, if approval of the AMR project is received after July 31, 2020, it would result in a delay in the implementation of the project to the second quarter of 2021 and negate the ability to achieve a full year of operational savings for Test Year 2021. Therefore, while it is not PNG(NE)'s preference, PNG(NE) has also noted that it is amenable to removing the AMR project (both the capital costs in 2020 and operating savings in Year 2021) from the Amended Application and to address the financial impacts via a deferral account following the approval of the AMR CPCN application.[11]

8.4 New CIS System

49. PNG(NE)'s Amended Application describes the rationale for a project being undertaken by PNG(NE), PNG-West and its sister utilities, AUI and HGL, to jointly implement a new CIS system to replace the existing legacy systems at the respective utilities. In the course of responding to information requests in this proceeding, PNG(NE) provided a significant amount of supplemental information on the CIS project, including detailed analyses of the cost impact of the project.[12] Based on evidence on record, PNG(NE) submits that pursuing a new CIS system with its affiliates is a prudent, necessary and cost-effective solution given the high likelihood that its legacy Banner CIS system is unlikely to be supported in the near future.

8.5 Automotive Cost Allocation

50. In Decision 2018-2019, the BCUC directed PNG(NE) to review and assess the effectiveness of the automotive cost allocation methodology. PNG(NE) has complied with this request and has proposed a modification to it automotive cost allocation methodology for Test Year 2020 and Test Year 2021.[13] A consequence of this modification is a lower allocation of consolidated PNG-West and PNG(NE) automotive costs to FSJ/DC and TR. This matter is addressed further in Section 17.2 of this submission.

8.6 Other Adjustments

51. In the course of responding to information requests, PNG(NE) identified certain corrections to forecast costs for 2020 and 2021. These included adjustments to certain

[11] Exhibit B-6, BCUC IR 81.1's
[12] Exhibit B-3, BCUC IR 10's;
[13] Exhibit B-2, Section 3.4.1.4

utility[14] and contractor costs.[15] The summary of adjustments presented in Section 6 of this submission incorporates these corrections.

9. MAINTENANCE EXPENSES

52. Information on PNG(NE)'s forecast maintenance expenditures for 2020 and 2021 was set forth in Section 2.4 of the Amended Application (Exhibit B-2). PNG(NE)'s responses to information requests further elaborate on the rationale and basis for the forecast amounts.

53. Subject to adjustments and undertakings identified through the regulatory review process (see summaries provided in Section 6 of this submission), FSJ/DC maintenance expenses for 2020 are forecast to be $508,000 which is $79,000 or 18.4% greater compared to $429,000 for Decision 2019, and $519,000 for 2021, which is $11,000 or 2.1% greater compared to 2020. For FSJ/DC, these cost increases are primarily driven by inflationary pressures as well as a sustained increase in the provision for leak repair activities due to the cumulative results obtained from integrity survey work and dig site results. PNG(NE) has conducted direct current voltage gradient (DCVG) / over-the-line surveys in recent years, which have identified areas of concern requiring investigation and possibly remediation.

54. TR maintenance expenses for 2020 are forecast to be $128,000 which is $44,000 or 52.3% greater compared to $84,000 for Decision 2019, and $131,000 for 2021, which is $3,000 or 2.1% greater compared to 2020. These cost increases are primarily driven by inflationary pressures and to an increase in the provision for plant maintenance and plant turnaround costs with an increased focus on safety and reliability activities.

55. PNG(NE) submits that the information presented in this proceeding provides the basis for the BCUC to find that the applied for maintenance expenses are just, reasonable and necessary to ensure PNG(NE) is able to continue to provide safe, secure and reliable natural gas service to its customers while also meeting the requirements of its regulatory authorities.

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[14] Exhibit B-3, BCUC IR 9.2

[15] Exhibit B-3, BCUC IR 57.1; Exhibit B-4, BCUC IR 2.1

10. ADMINISTRATIVE AND GENERAL EXPENSES

56. PNG(NE) has provided a substantial amount of information in the filed Exhibits in support of its forecast administrative and general expenditures for 2020 and 2021. PNG(NE)'s application narrative on these expenditures was set forth in Section 2.5 of Exhibit B-2 for both FSJ/DC and TR. PNG(NE)'s responses to information requests further elaborate on the rationale and basis for the forecast amounts.

57. FSJ/DC administrative and general expenses, before shared service cost allocations, for 2020 are forecast to be $1.152 million which is $107,000 or 10.3% greater compared to $1.045 million for Decision 2019, and $1.023 million for 2021, which is $130,000 or 11.3% lower compared to 2020. TR administrative and general expenses, before shared service cost allocations, for 2020 are forecast to be $153,000 which is $17,000 or 12.7% greater compared to $135,000 for Decision 2019, and $147,000 for 2021, which is $5,000 or 3.5% lower compared to 2020. PNG(NE) notes that PNG-West shared services cost recoveries are addressed in Section 11 of this submission.

58. The noted cost variances for both 2020 and 2021 are primarily driven by:

(i) Provision in 2020 for regulatory costs pertaining to the review of the 2019 Consolidated Resource Plan (filed every 5 years) and this 2020-2021 Revenue Requirements Application (filed every 2 years), with no comparable costs in 2019 or 2021;

(ii) Provision to provide for co-sourcing of a portion of the internal controls testing to a professional services firm as a result of an increased scope of internal controls testing since PNG(NE) is no longer part of AltaGas Ltd.;

(iii) A decrease in the allocation of consolidated PNG-West/PNG(NE) insurance expense, offset in part by an increase in property insurance premiums, which are approximately 14.0% higher over the prior year due to insurance market changes resulting from recent utility-related events;

(iv) Lower employee benefit costs primarily due to lower non-pension post-retirement benefit (NPPRB) costs in 2020, as well as a reduced provision for health spending account benefits for bargaining unit employees due to nominal participation, and to lower pension costs in 2021, as well as the impact of the

workforce reduction proposed for the AMR project and the anticipated employee benefit cost savings; and

(v) General inflationary pressures on most underlying costs.

59. PNG(NE) submits that the factors contributing to the increase in administrative and general expenses were subject to a thorough examination via the responses provided to information requests in this proceeding.[16] PNG(NE) further submits that the information presented in this proceeding provide the basis for the BCUC to find that the applied for administrative and general expenses are just, reasonable and necessary to ensure PNG(NE) is able to continue to provide safe, secure and reliable natural gas service to its customers.

11. PNG-WEST SHARED SERVICES RECOVERY FROM PNG(NE)

60. PNG(NE) continues to apply the shared service cost allocation method established by the 2012 Shared Services Study that was implemented and approved by the BCUC as part of the review of the PNG-West's 2013 revenue requirements application.[17] Information supporting PNG-West shared services cost recoveries from PNG(NE) is set forth under Section 2.6, Shared Services Cost Allocation to PNG(NE) of the Amended Application.

61. As described in the Amended Application, the recovery by PNG-West of pooled shared service costs from the PNG(NE) divisions has increased by a considerable amount for 2020 and 2021 compared to 2019. This increase can primarily be attributed to increases in underlying costs included in the PNG-West cost pools as the PNG(NE) allocation percentages applied for each cost pool have remained relatively flat.

11.1 Shared Corporate Services Costs

62. The most significant contributor to the increased allocation pertains to PNG(NE)'s proposal to recover the full amount of its allocation of TriSummit Utilities Inc. (TSU, formerly AltaGas Canada Inc. (ACI)) Shared Corporate Services Costs commencing 2020. While historically, the BCUC has generally capped recoveries of Shared Corporate Services Costs to

[16] Exhibit B-3, BCUC IR 14's and 15's; Exhibit B-6, BCUC IR 76's and 77's
[17] BCUC Order G-114-13, Decision, page 35

a historic amount plus inflationary increases, PNG(NE) has represented that it expects to seek recovery of all costs allocated by its parent company associated with maintaining its capital structure, providing access to capital and delivering various other corporate services. PNG(NE) submits that it would not realize the benefits associated with the shared services model if it were not part of TSU group of companies, and that to achieve a fair and reasonable result in respect of recovery of necessary costs of services for both customers and its shareholder, PNG(NE) reiterates that full recovery of prudent and reasonable costs from TSU is appropriate.

63. PNG(NE) notes its Amended Application includes a proposal to defer most of the incremental amount of these costs for future recovery and has reflected a cost adjustment to effect this as noted in Section 2.5.8 of the Amended Application. The amount of the deferral for FSJ/DC is $377,000 for Test Year 2020 and $373,000 for Test Year 2021, and the amount of the deferral for TR is $24,000 for Test Year 2020 and $25,000 for Test Year 2021. The BCUC has requested a discussion of alternatives to PNG(NE)'s proposal and notes that this is addressed in Section 14.2.1 of this submission.

11.2 Other Shared Services Cost Pool Increases

64. The PNG-West cost pools also reflect increased costs for additional initiatives that will benefit PNG(NE), including: additional staffing in the areas of engineering, Indigenous relations and land management; sustainment costs for the Maximo asset management system; third-party system integrity support; and JDE and HRIS sustainment costs. Information on these incremental costs and the benefits to be provided to PNG(NE) is provided in Section 2.6 of the Amended Application.

65. As per the Amended Application and as supported by additional information provided in response to information requests,[18] PNG(NE) submits that cost pools and cost allocators have been consistently applied, and that the resulting allocations for cost recovery from PNG(NE) by PNG-West are fair and reasonable and should be accepted as filed.

12. TRANSFERS TO CAPITAL

66. PNG(NE) continues to apply the capital overhead allocation methodology established

[18] Exhibit B-3, BCUC IR 15's to 19.1; Exhibit B-6, BCUC IR 79's to 80's

by the 2010 Overhead Capitalization Study to calculate the transfers of budgeted operating, administrative and general expenses to test year capital projects. This methodology was implemented and approved by the BCUC as part of the negotiated settlement agreement on PNG(NE)'s 2011 revenue requirements application,[19] with minor amendments approved under Decision 2012.[20] PNG(NE) continues to apply the same overhead capitalization rates for both rate setting and external reporting purposes.

67. Information supporting transfers to capital is set forth under Section 2.7, Transfers to Capital (Capitalized Overhead) of the Amended Application, and is supported by additional information provided in response to information requests.[21]

68. Transfers to capital for FSJ/DC were shown to increase moderately, from an average of $0.554 million for the period 2015 to 2019, to $0.621 million for 2020 and $0.556 million for 2021. Transfers to capital for TR were also shown to increase moderately, from an average of $43,800 for the period 2015 to 2019, to $60,000 for 2020 and $47,000 for 2021. The increases noted for 2020 and the decreases for 2021 reflect a respective increase and decrease in capital expenditures in these years compared to the 5-year average capital expenditures.

69. Based on the information presented in the course of this proceeding, PNG(NE) submits that the allocation method has been consistently applied and that the resulting capital allocation of overhead costs is fair and reasonable.

13. DEPRECIATION

70. As described in Section 2.9 of the Amended Application, the forecast Test Year 2020 and Test Year 2021 depreciation expense has been calculated using depreciation rates determined following the 2017 Depreciation Study, and as approved by the BCUC in Order G-164-18A on PNG(NE)'s 2018-2019 revenue requirements application.

71. The forecast Test Year 2020 and Test Year 2021 cost of service also includes a provision

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[19] BCUC Order G-93-11, Appendix A, page 5
[20] BCUC Order G-168-12, Decision, page 34
[21] Exhibit B-3, BCUC IR 20's

for net salvage, as recommended in the 2017 Depreciation Study and as directed and approved by the BCUC under Order G-222-18. PNG(NE) is continuing with the phase-in provisions for negative salvage values over a 5-year period that commenced in 2019, with Test Year 2020 and Test Year 2021 representing year 2 and year 3 of the 5-year phase-in period, respectively. In this regard, PNG(NE) has incorporated negative salvage phase-in amounts in incremental amortization expense for Test Year 2020 and Test Year 2021 for FSJ/DC of $334,000 and $501,000, respectively, and for TR of $78,000 and $117,000, respectively.

14. DEFERRAL ACCOUNTS AND AMORTIZATION

72. Each of the deferral accounts used by PNG(NE) is described in the Amended Application under Section 2.10, Amortization, where the narrative provides a description of the individual deferral accounts, as well as a discussion of changes in amortization expense from Decision 2019 to 2020 and 2021. Additional information on PNG(NE)'s deferral accounts is provided in the Continuity of Deferred Charges tables provided under Tab Schedules, Tab 2, pages 12 to 15 in the Amended Application for each of FSJ/DC and TR.

73. PNG(NE) notes that the BCUC's Decision on the PNG(NE) 2013 revenue requirements application under Order G-131-13 addressed two important issues with regards to deferral accounts, mainly the appropriate length of amortization period and the appropriate financing charge to be applied to balances. PNG(NE) submits that it has adhered to the criteria established under this order.

74. In the discussion that follows, PNG(NE) summarizes requests for changes to deferral accounts, including the elimination of accounts no longer necessary and the creation of new accounts. The discussion also addresses the disposition of deferred amounts, specifically where changes to previously established amortization of balances is being sought.

14.1 Request to Eliminate Deferral Account

75. PNG(NE) has requested approval to eliminate the Studies deferral account that was established to accumulate costs relates to a sweet gas supply option study for the Tumbler Ridge division. The BCUC approved PNG(NE)'s request to amortize costs in this deferral account over a period of three years in Order G-132-16 on PNG(NE)'s 2016-2017 revenue requirements application. As this account was fully amortized in 2018 and there is no further need, PNG(NE) is requesting the dissolution of this deferral account.

14.2 Request for New Deferral Accounts

76. PNG(NE) has requested three new deferral accounts, as summarized in the discussion that follows.

14.2.1 Shared Corporate Services Costs Deferral

77. As described in Section 2.5.8 of the Amended Application, and as discussed in Section 14 of this submission, PNG(NE) is proposing that a new interest bearing deferral account be established to record a portion of the Shared Corporate Services Costs to be amortized at a future date instead of being recovered in the period the services are received by PNG(NE). The amount of the deferral for FSJ/DC is $377,000 for Test Year 2020 and $373,000 for Test Year 2021, and the amount of the deferral for TR is $24,000 for Test Year 2020 and $25,000 for Test Year 2021.

14.2.1.1 Considerations on Amortization Period

78. PNG(NE)'s proposal was to seek approval for the amortization of this deferral account in future years as PNG(NE) attaches more customer volumes in the system. As noted by PNG(NE),[22] that there is no significant economic growth forecast for the FSJ/DC or TR divisions in the current test period was a determining factor in not seeking amortization of the deferral in 2020 and 2021.

79. On June 10, 2020, the BCUC issued a letter requesting that further consideration be given to this matter in this submission.[23] Specifically, based on a scenario where PNG(NE) is permitted to recover the full Shared Corporate Services Cost allocation from its parent company, PNG(NE) was asked to discuss the advantages and disadvantages of any alternatives to PNG(NE)'s proposal. Specific alternatives to be addressed are:

i) Recovery of the full Shared Corporate Services Cost allocation in customer rates in the current 2020-2021 test period;

[22] Exhibit B-3, BCUC IR 15.3
[23] Exhibit A-8

ii) Allocation of the deferred portion of Shared Corporate Services cost allocation to a deferral account and commence amortization of the deferred portion in the current test period, over a period of one, three and five years; and

iii) Any other alternatives.

80. The following are PNG(NE)'s submissions on this matter.

14.2.1.1.1 Full Recovery in Current 2020-2021 Test Period

81. PNG(NE) proposed to commence amortization of the deferral account when the economic circumstances improve and suggest that this matter be revisited in the 2022-2023 revenue requirements submission.[24] In response to BCUC IR 15.6 in Exhibit B-3, PNG(NE) provided illustrative impacts on residential customer rates in 2020 and 2021 if recovery of the full amount of the Shared Corporate Services Costs were approved in the current test period. For FSJ/DC, there would be a 2.6% rate increase in 2020 (i.e. overall rate increase of 14% compared to the 11.4% rate increase as per the Amended Application). There would be no further rate impact on 2021 as the increased recovery would now be embedded in the 2020 cost of service. For TR, there would be a 1.4% rate increase in 2020 (i.e. overall rate increase of 4.7% compared to the 3.3% rate increase as per the Amended Application). Again, there would be no further rate impact on 2021 as the increased recovery would be embedded in the 2020 cost of service.

82. Advantages of this approach is that there would be no intergenerational inequity created for ratepayers as a result of shifting the recovery of current period costs to future years. The primary disadvantage of this approach is adverse impact on customer rates for 2020.

14.2.1.1.2 Amortization Periods of One, Three and Five Years

83. In response to BCUC IR 15.7 in Exhibit B-3, PNG(NE) provided illustrative impacts on residential customer rates based on amortization periods of one, three and five years.

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[24] Exhibit B-3, BCUC IR 15.5

84. Under a one-year amortization, assuming future period deferred amounts remain relatively constant, the 2020 rate increase impact of 2.6% for FSJ/DC and 1.4% for TR as per the full recovery in the current test period scenario is theoretically deferred until 2021 when the full amount of the Shared Corporate Services Costs amortization is embedded in the cost of service. That is, the overall increase of 2.6% for FSJ/DC and 1.4% for TR as per the full recovery in the current test period scenario would be deferred from 2020 to 2021.

85. Under a three-year amortization, assuming future period deferred amounts remain relatively constant, the 2020 rate increase impact of 2.6% for FSJ/DC and 1.4% for TR as per the full recovery in the current test period scenario will theoretically be gradually implemented at a rate of one-third in each of three years, with the full amount of the Shared Corporate Services Costs embedded in the cost of service in the third year.

86. Similarly, under a five-year amortization, assuming future period deferred amounts remain relatively constant, the 2020 rate increase impact of 2.6% for FSJ/DC and 1.4% for TR as per the full recovery in the current test period scenario will theoretically be gradually implemented at a rate of one-fifth in each of three years, with the full amount of the Shared Corporate Services Costs embedded in the cost of service in the fifth year.

87. The primary advantage of this approach is the more gradual impact on customer rates, with greater relief from rate increase impacts coming from a longer amortization period. The primary disadvantage would be intergenerational inequity resulting from the shift in recovery of current period costs to future years, however PNG(NE) observes the timeframes given consideration here are relatively short.

14.2.1.1.3 Other Alternatives

88. PNG(NE) has given consideration as to other possible alternatives for amortization of the Shared Corporate Services Cost deferral account, however, has not identified any beyond those addressed in the preceding discussion.

89. In order to achieve a fair and reasonable result in respect of recovery of necessary costs of service for both customers and its shareholder, PNG(NE) reiterates that full recovery of the prudent and reasonable Shared Corporate Services Costs from TSU is appropriate. PNG(NE) further submits that the implementation of a deferral account can mitigate near-term effect on customer rates and it is PNG(NE)'s recommended approach that a portion of the Shared Corporate Services Costs be recorded in a deferral account to be amortized at a

future date.

14.2.1.2 Applicable Interest Rate

90. Further, PNG(NE) had originally proposed that PNG(NE)'s short-term interest rate be applied to the Shared Corporate Services Costs deferral account, however, PNG(NE) concedes that applying the WACD rate would be more appropriate as a longer amortization period is anticipated for this deferral.[25] PNG(NE) has reflected this change in the summary of adjustments for both FSJ/DC and TR as per Section 6 of this submission.

14.2.2 Accelerated CCA Deferral

91. As described in the Section 2.10 of the Amended Application, PNG(NE) has utilized the accelerated CCA provision available under the Canadian federal government's Accelerated Investment Incentive for 2019, and has recorded the effect of this action in short-term interest deferral accounts for both FSJ/DC and TR. PNG(NE) seeks BCUC approval to record the impact of the accelerated CCA provision, calculated to be $127,000 for FSJ/DC and $8,000 for TR, to these credit deferral accounts and to fully amortize them in Test Year 2020 to the benefit of ratepayers. PNG(NE) has also requested the dissolution of these deferral account after Test Year 2021.

14.2.3 Rate Smoothing Deferral

92. Further to Section 5 of this submission, PNG(NE) has requested approval to create a short-term interest bearing rate deferral account in 2020 to levelize the impact of the combined net revenue deficiencies for 2020 and 2021 to be fully amortized in 2021 for both the FSJ/DC and TR divisions. PNG(NE) notes that this same rate smoothing deferral mechanism was approved in the 2018-2019 revenue requirements application proceeding under Order G-164-18A.

15. INCOME TAXES

93. On June 16, 2020, PNG(NE) submitted an evidentiary update (Exhibit B-2-2) advising that it had identified an error that pertained to the modelling and calculation of the income

[25] Exhibit B-6, BCUC IR 77.1

tax impacts of certain IT-related capital additions in the test period. Specifically, PNG(NE) had identified that certain IT-related capital projects additions were erroneously excluded from Capital Cost Allowance (CCA) Class 12 (Software) additions for purposes of determining CCA deductions in the calculation of income taxes for both 2020 and 2021. In correcting this error, for FSJ/DC, the cost of service would be reduced by $445,000 for Test Year 2020 and increased by $61,000 for Test Year 2021, and for TR, the cost of service would be reduced by $32,000 for Test Year 2020 and increased by $5,000 for Test Year 2021. PNG(NE) has included these corrections in the summary of adjustments proposed for inclusion in the final regulatory schedules as per Section 6 of this submission.

16. RATE BASE AND CAPITAL EXPENDITURES

94. As per the Amended Application, PNG(NE)'s forecast mid-year rate base for FSJ/DC for 2020 is $78.6 million and for 2021 is $84.2 million (see FSJ/DC Tab Schedules, Tab 2, page 1, line 18 in Exhibit B-2) compared to $72.8 million for 2019. The forecast mid-year rate base for TR for 2020 is $5.6 million and for 2021 is $5.9 million (see TR Tab Schedules, Tab 2, page 1, line 17 in Exhibit B-2) compared to $4.3 million for 2019. These amounts are predominantly made up of mid-year values for net plant in service which for FSJ/DC is forecast to increase from $80.0 million for 2019 to $85.5 million in 2020, and to $91.5 million in 2021, and for TR is forecast to increase from $5.0 million for 2019 to $6.2 million in 2020, and to $6.6 million in 2021.

16.1 Plant in Service

95. Subject to adjustments noted in Section 6 of this submission, PNG(NE) has forecast capital expenditures for FSJ/DC, before overhead, to be $9.187 million in 2020 and $5.899 million in 2021, compared to average capital expenditures of $5.093 million over the prior five years. Capital expenditures for TR, before overhead, are forecast to be $0.896 million in 2020 and $0.400 million in 2021, compared to average capital expenditures of $0.552 million over the prior five years.

96. The details and justification in support of PNG(NE)'s forecast capital additions for FSJ/DC and TR is provided under the respective division's Tab Application in Section 2.13.1.1, Capital Additions of Exhibit B-2, with extensive additional detail provided in response to Questions 27's to 44's, inclusive, in Exhibit B-3, in response to questions in Exhibit B-1, in response to Questions 7's to 9's, inclusive, in Exhibit B-4, and in response to Questions 81's to

89's, inclusive, in Exhibit B-6. Additional information on significant capital items addressed in the proceeding is provided in the discussion that follows.

16.1.1 Fort St. John / Dawson Creek

16.1.1.1 Mobile / Heavy Equipment Replacement

97. As described in the Amended Application, PNG(NE) has proposed increased spending on replacement vehicles and heavy equipment for 2020 and 2021 compared to recent years, with $529,000 forecast for 2020 and $775,000 forecast for 2021.[26] PNG(NE) notes that all heavy equipment purchases are to replace existing equipment. Further, planned vehicle replacements are all in compliance with PNG(NE)'s established replacement criteria.

98. PNG(NE) notes that in recent years, investment in heavy equipment has been deferred to minimize short-term costs, however, several critical units are now at the end of life and are either becoming obsolete or repair costs are increasing to significant share of replacement cost. PNG(NE) submits that replacement of identified equipment is necessary at this time, as there is considerable risk to not doing so.[27]

16.1.1.2 Mechanical Coupling Replacement

99. As described in the Amended Application[28] and in response to information requests,[29] similar to many other utilities across North America, PNG(NE) has an ongoing multi-year program to remove and replace aging and obsolete mechanical couplings on the FSJ/DC distribution system, with forecast costs for 2020 of $519,000 and 2021 of $530,000. Based on the current risk assessment, it is anticipated that this program can be safely and effectively completed over a period of 15 to 20 years for FSJ and approximately 38 years for DC. This replacement project is considered necessary as underground leaks caused by failed couplings produce risks to public safety and system integrity.

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[26] Exhibit B-2, FSJ/DC Section 2.13.1.1, page 65 and 73
[27] Exhibit B-3, BCUC IR 28.2
[28] Exhibit B-2, FSJ/DC Section 2.13.1.1, page 65 and 73
[29] Exhibit B-3, BCUC FSJ/DC IR 29's; Exhibit B-6, BCUC FSJ/DC IR 84's

16.1.1.3 PE2306 Replacement

100. As described in the Amended Application[30] and in response to information requests,[31] PNG(NE) also has an ongoing multi-year program to replace PE2306 piping on the FSJ/DC distribution system, with forecast costs for 2020 of $315,000 and 2021 of $285,000.

101. Based on the current risk assessment, it is anticipated that this program can be safely and effectively completed over the next 20 years. Underground leaks are caused by the inherent brittle nature of the PE2306 piping, and due to its brittle properties, repairs to the PE2306 piping may create further issues. This replacement project is considered necessary as underground leaks caused by PE2306 failures produce risks to public safety and system integrity.

16.1.1.4 AMR Project

102. PNG(NE)'s Amended Application includes capital expenditures required to implement automated meter reading (AMR) infrastructure in the divisions it serves, including FSJ/DC and TR. As noted in Section 8.3 of this submission, in March 2020, PNG(NE) submitted an application to the BCUC for a CPCN proposing to update and replace the current manual meter reading process for residential and commercial customers with AMR. As noted, the Amended Application indicated the project had an estimated capital cost of $3.695 million which differed from that of $3.862 million as per the CPCN application. A reconciliation of project costs was provided n response to BCUC IR 32.1, noting that the CPCN application costs reflected an update to the $US/$CAD exchange rate, as well as an added provision under project management for quality assurance. PNG(NE) has included an update to the AMR project cost in the summary of adjustments presented in Section 6 of this submission.

103. A number of information requests focused on whether the AMR project costs should be included in the Amended Application. PNG(NE) noted that it remains hopeful that approval of the AMR project will be granted prior to the filing of the compliance regulatory schedules in this proceeding, however, it is amenable to removing the AMR project (both the capital costs in 2020 and operating savings in Year 2021) from the Amended Application and to

[30] Exhibit B-2, FSJ/DC Section 2.13.1.1, page 65 and 73

[31] Exhibit B-3, BCUC FSJ/DC IR 29's; Exhibit B-6, BCUC FSJ/DC IR 84's

address the financial impacts via a deferral account following the approval of the AMR CPCN application.

16.1.1.5 Asset Information and Data Management Systems

104. As described in the Amended Application and further elaborated upon in response to information requests, PNG(NE)'s forecast capital expenditures include costs related to several asset management and asset information systems, including costs for the final phase of the geographic information system (GIS),[32] the ongoing asset records modernization,[33] the hydraulic modelling system replacement/upgrade,[34] and the update to change management processes.[35] PNG(NE) submits that the planned investments in new and upgraded systems and processes that incorporate contemporary industry best-practices and technology are critical to its integrity management and maintenance management programs, will improve efficiency and consistency, and will improve management capabilities and the capacity for reporting and regulatory compliance.

16.1.1.6 Baldonnel Line Lowering

105. As described in the Amended Application[36] and further elaborated upon in response to information requests,[37] PNG(NE)'s forecast capital expenditures include costs related to ongoing evaluation of the requirement to lower or relocate its lines at Baldonnel due to ongoing geotechnical concerns and third-party infrastructure encroachment. Capital funds of $155,000 and $158,000 have been allocated in 2020 and 2021, respectively, for phase two of this initiative which includes continued slope stability monitoring and employment of required mitigation measures for item identified as high risk in the initial works completed in 2019. Ongoing monitoring will inform any requirements for a more comprehensive response for which additional capital funds will be sought for 2022.

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[32] Exhibit B-3, BCUC IR 37's; Exhibit B-6, BCUC IR 79.2, 79.3 and 88's
[33] Exhibit B-3, BCUC IR 34's; Exhibit B-6, BCUC IR 79.4
[34] Exhibit B-3, BCUC IR 44's; Exhibit B-6, BCUC IR 79.4 and 89's
[35] Exhibit B-3, BCUC IR 35's
[36] Exhibit B-2, FSJ/DC Section 2.13.1.1, page 70 and 77 and Section 3.4.1.3
[37] Exhibit B-3, BCUC IR 40's; Exhibit B-6, BCUC IR 86.1

16.1.1.7 Rolla Lateral Repair and Recommissioning

106. As described in the Amended Application[38] and further elaborated upon in response to information requests,[39] PNG(NE)'s forecast capital expenditures for 2020 include costs of $105,000 to undertake front end engineering and design (FEED) and planning for repair and recommissioning of the Rolla lateral located near Dawson Creek. Recommissioning of the Rolla lateral will allow PNG(NE) to complete high integrity risk repairs on the single gas feed for Dawson Creek while still servicing the city and surrounding areas. Capital expenditures for 2021 include $345,000 for the construction execution of this initiative.

16.1.1.8 Cecil Lake Aluminum Pipeline Replacement

107. As described in the Amended Application,[40] PNG(NE) had included capital expenditures in 2018 and 2019 related to the replacement of the aluminum pipeline infrastructure in the Cecil Lake area. Reasons for the replacement included the fact that aluminum natural gas pipelines are no longer commonly used, posing an integrity risk, and that PNG(NE) does not have the in-house specialized training or tooling to respond to and repair emergency events related to the aluminum pipeline.

108. During 2018, PNG(NE) developed a comprehensive replacement design for the 14 km Cecil Lake aluminum pipeline, however, at that time industrial gas usage dropped off due to producers ceasing operations in the associated service area which has left the existing Cecil Lake pipeline underutilized. PNG(NE) contracted an impartial third party to execute further integrity inspection including external corrosion direct assessment and to develop an associated risk mitigation alternatives analysis given the load reduction and subsequent identification of repair resources. The report highlighted system integrity concerns that could be downgraded and managed via ongoing monitoring and identified asset areas that should be focused on to further reduce risk but have allowed for the deferral of a high cost pipeline replacement.

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[38] Exhibit B-2, FSJ/DC Section 2.13.1.1, page 71 and 75

[39] Exhibit B-3, BCUC IR 42.1

[40] Exhibit B-2, FSJ/DC Section 3.1.1, page 91 and Section 3.1.2, page 95

109. In response to information requests,[41] PNG(NE) provided considerable supplemental information around costs and the change from the original scope of this project due to the sharp decline in the demand for fuel gas for compressors and general industrial activity and demand for gas in the Cecil Lake area, and justification as to why previously proposed activities were determined to no longer be valid. PNG(NE) submits that the Cecil Lake system continues to be monitored from both system integrity and system capacity perspectives.

16.1.2 Tumbler Ridge

16.1.2.1 Processing Plant Improvements

110. As described in the Amended Application[42] and in response to information requests,[43] PNG(NE) has presented a number of processing plant improvements for completion in 2020 and 2021, including: the purchase and installation of a dehydration burner; the purchase and installation of a line heater; the purchase and installation of a flare stack ignition system; the upgrade and installation of the ignition on the amine boiler; replacement of an inlet control valve; and the purchase and installation of a new pump for the amine system.

111. PNG(NE) confirmed that all of the equipment noted for replacement was installed in 1984. With components having estimated useful lives of between 25-30 years, all of this equipment is considered to have exceeded their useful lives and must be replaced. PNG(NE further noted that any delays to these projects increase the risk profile for PNG(NE) to be able to maintain a safe and reliable operation at the processing plant.

112. Lastly, PNG(NE) notes that in the cover letter to Exhibit B-6, the submission of PNG(NE) responses to BCUC IR No. 2, PNG(NE) advised that the costs included in Test Year 2020 for processing plant improvements erroneously included a duplicate amount of $60,000 for materials in the $174,000 cost to purchase and install a dehydration burner. PNG(NE) has reflected the correction of this error in the summary of adjustments included in Section 6 of this submission.

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[41] Exhibit B-3, BCUC IR 51's; Exhibit B-6, BCUC IR 91's; Exhibit B-6-1, BCUC Confidential IR 1's
[42] Exhibit B-2, TR Section 2.13.1.1, page 61 and 64
[43] Exhibit B-4, BCUC IR 7's

16.1.2.2 Transmission Pipeline Repair

113. As described in the Amended Application[44] and in response to information requests,[45] PNG(NE) plans to modify the transmission system from the TR process plant to the TR gate station to facilitate the use of inline inspection and inline cleaning tooling. Expenditures forecast for 2020 are to focus on phase one feasibility and front end engineering and design activities, while 2021 costs are to focus on phase two which will include detailed engineering, permitting and execution planning to arrive at a class 3 cost estimate. Phase three of this project is anticipated to proceed in 2022 and includes construction and commissioning activities.

16.1.3 Other Adjustments

114. In the course of responding to information requests, PNG(NE) identified certain corrections to forecast capital expenditures for 2020 and 2021. These included a reclassification of FSJ/DC costs included in BCUC 475 Distribution Mains to BCUC 465 Steel Main Replacement,[46] FSJ/DC and TR capital costs pertaining to new BCOGC integrity related projects[47] and removal of costs in TR for boiler replacement that were double counted.[48] The summary of adjustments presented in Section 6 of this submission incorporates these corrections.

115. PNG(NE) submits that the evidence presented in the course of this proceeding supports the identified capital expenditures for 2020 and 2021 as prudent and necessary in order to ensure that PNG(NE) is able to continue to provide its customers with safe, reliable and secure gas delivery service in 2020, 2021 and into the future, and that they should be approved.

16.2 Capital Structure and Return on Capital

116. For the purposes of its Amended Application, PNG(NE) has used the Decision 2019

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[44] Exhibit B-2, TR Section 2.13.1.1, page 62 and 63
[45] Exhibit B-4, BCUC IR 8's
[46] Exhibit B-3, BCUC IR 30.1
[47] Exhibit B-6, BCUC IR 68.4
[48] Exhibit B-6, Cover Letter

approved rate of return on common equity (ROE) of 9.25% for FSJ/DC and of 9.5% for TR, and the approved common equity thickness of 41.0% for FSJ/DC and of 46.5% for TR following the issuance of the Stage 2 GCOC Decision in 2014 and the BCUC Decision on the FortisBC Energy Inc.'s (the Benchmark Utility) application for its Common Equity Component and Return on Equity for 2016.[49] PNG(NE) notes that in the latter, the BCUC ordered no changes to the Benchmark Utility's common equity component and no changes to the ROE, and that these metrics would remain in effect until otherwise determined by the BCUC, and further, that the Automatic Adjustment Mechanism Formula was suspended indefinitely.

17. OTHER MATTERS

17.1 Reporting on Significant Capital Projects

117. As noted in Section 3.4.1.1 of the Amended Application, PNG(NE) was directed to provide a proposal for a report to the BCUC, to be filed annually, which outlines future construction of extensions and new facilities as well as significant system modifications or additions that are planned. PNG(NE) concurred that there is a need for a capital reporting process that will allow the BCUC to give consideration to PNG(NE)'s planned future capital expenditures in advance of construction, particularly with regard to assessing whether a CPCN process for planned capital expenditures would be in the public interest.[50]

118. In the Amended Application PNG(NE) has proposed a reporting process that it believes will provide the BCUC with the information necessary to make the noted determination. Key elements of the proposed reporting include:

i) Capital reporting would be an element of the Annual Report to the British Columbia Utilities Commission (Annual Report) to be filed by April 30th each year;

ii) Reporting would be on forecast and historic capital expenditures;

iii) Focus would be on planned non-recurring projects that would capture system extensions, new facilities and significant system modifications or additions and

[49] BCUC Order G-129-16
[50] BCUC Order G-164-18A, directive 5

significant items pertaining to the maintenance and operation of existing assets; and

iv) A reporting threshold of a cumulative minimum total capital project expenditure of $500,000.

119. PNG(NE) notes that on the matter of assessing whether a CPCN process for planned capital expenditures would be in the public interest, several BCUC information requests[51] explored what might be an appropriate dollar value threshold for a project that would necessitate the submission of a CPCN application. In response to certain of these queries, PNG(NE) noted that it has historically made use of an informal threshold of $1,000,000 as a general guideline in deciding on whether to file CPCN or section 44.2 applications. However, based on a cursory review of other utilities under the BCUC's jurisdiction, PNG(NE) suggested that a higher CPCN threshold between $1,500,000 to $2,000,000 may be more appropriate.

120. PNG(NE) submits that the evidence presented in the Amended Application and in the course of this proceeding[52] supports the proposed capital reporting as a reasonable and appropriate approach that will allow the BCUC an opportunity to assess PNG(NE)'s planned future capital expenditures and should be approved as proposed.

17.2 Automotive Cost Allocation

121. As noted in Section 3.4.1.4 of the Amended Application, PNG(NE) was directed to review and assess the effectiveness of the automotive cost allocation methodology with respect to variances in forecast and actual expense allocations and, based on this assessment, provide recommendations for future handling and allocation of costs among the PNG and PNG(NE) divisions.[53]

122. In the Amended Application PNG(NE) presented its analysis and evaluation of its historic approach to the allocation of automotive costs, and made recommendations to amend the cost pool forecast and cost pool allocation methodologies with a view to reduce over/under allocations between capital and operating costs and between the PNG-West and

[51] Exhibit B-3, BCUC IR 62.8; Exhibit B-6, BCUC IR 94.4 to 94.9.1
[52] Exhibit B-3, BCUC IR 61's to 64's; Exhibit B-6, BCUC IR 94's
[53] BCUC Order G-164-18A, Reasons for Decision, Section 3.0

PNG(NE) divisions, including:

i) Base the test period forecast consolidated automotive cost pool on the actual costs of the prior year with a 2% provision for inflation;

ii) Continue to apply the current budgetary convention for allocating forecast consolidated automotive costs to capital, whereby the divisional percentage of capital labour costs of consolidated labour costs is applied to the consolidated automotive cost pool, and continue to apply the current administrative convention of allocating actual Automotive costs to capital, whereby a 15% factor is applied to capital labour costs and capitalized; and

iii) Establish the test period forecast operating automotive cost pool as the consolidated automotive cost pool less amounts identified as being attributable to capital, and allocate the forecast operating cost pool to divisions on the basis of the five-year rolling average of each division's actual percentage distribution of operating automotive costs.

123. PNG(NE) submits that it has undertaken considerable analysis and evaluation of historic results and the implications of the changes it has proposed, as well as additional analysis and evaluation in response to information requests in this proceeding.[54] PNG(NE) further submits that, while there is uncertainty inherent in any forecast methodology, the proposed cost pool forecasting and allocation will reduce the magnitude of the over/under allocation of automotive costs between cost categories and between divisions, and should be approved as proposed.

18. CUSTOMER RATES

124. In order to enable PNG(NE) to have the opportunity to recover its cost of providing service to its customers in 2020 and 2021, after provision for the rate deferral mechanism (see Section 5 of this submission), PNG(NE) is seeking BCUC approval to increase its 2020 customer rates to reflect the recovery of the projected 2020 revenue deficiency of $1.643 million for FSJ/DC and of $56,000 for TR, and to increase its 2021 customer rates to reflect the recovery

[54] Exhibit B-6, BCUC IR 95's

of the projected 2021 revenue deficiency of $1.792 million for FSJ/DC and of $63,000 for TR, subject to adjustments based on changes identified through the information request process and summarized in Section 6 of this submission.

125. For rate making purposes, the 2020 and 2021 revenue deficiencies have been allocated to customers based on forecast margin recovery by customer class as shown in the Amended Application at FSJ/DC Tab Schedules, Tab 6 Rates, pages 8 and 28 and at TR Tab Schedules, Tab 6 Rates, pages 3 and 14. The use of the gross margin allocation method by PNG(NE) has been approved by the BCUC for many years and, as reflected in PNG(NE)'s instant application, has been applied on a basis consistent with previous years.

126. The rate changes resulting from the projected revenue deficiencies for 2020 and 2021, before such adjustments as proposed through the information response process and summarized in Section 6 of this submission, are presented in Table 2 in Section 1.4 of Exhibit B-2 for each of FSJ/DC and TR. Before proposed adjustments, FSJ and DC residential customers were forecast to have rate increases of 11.4% and 11.9%, respectively, in 2020 and of 11.1% and 11.6%, respectively, in 2021, and TR residential customers were forecast to have rate increases of 3.2% in 2020 and 3.5% in 2021. FSJ and DC small commercial customers were forecast to have rate increases of 9.8% and 11.5%, respectively, in 2020 and of 9.7% and 11.2%, respectively, in 2021, and TR small commercial customers were forecast to have rate increases of 3.0% in 2020 and 3.3% in 2021.

127. For FSJ/DC, PNG(NE) is also seeking BCUC approval of a 2020 credit RSAM rate rider equal to $0.022/GJ and a 2021 credit RSAM rate rider equal to $0.012/GJ as shown in Exhibit B-2 at FSJ/DC Tab Schedules, Tab 6 Rates, pages 19 and 39, respectively. For TR, PNG(NE) is seeking BCUC approval of a 2020 credit RSAM rate rider equal to $0.923/GJ and a 2021 credit RSAM rate rider equal to $0.406/GJ as shown in Exhibit B-2 at TR Tab Schedules, Tab 6 Rates, pages 10 and 21, respectively. The determination of the RSAM rate riders is based on a two-year amortization period, consistent with the practice established in the 2013 revenue requirements application proceeding.

19. JUST AND REASONABLE RATES

128. Section 60(1) of the *Utilities Commission Act* establishes the obligation of the BCUC to set rates as follows:

> "In setting a rate under this Act

(a) the commission must consider all matters that it considers proper and relevant affecting the rate,

(b) the commission must have due regard to the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59,

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and

(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,

(b.1) the commission may use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period, and

(c) if the public utility provides more than one class of service, the commission must

(i) segregate the various kinds of service into distinct classes of service,

(ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self contained unit, and

(iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates fixed for any other unit."

Section 59(5) states:

"In this section, a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason."

129. In a decision rendered by the BCUC in 2006 in respect of a PNG-West revenue requirements application, the BCUC discussed in detail the legal requirements under the *Utilities Commission Act* to fix rates that permit a utility the opportunity to recover all of its cost of providing service, including the fair rate of return on common equity approved for the utility by the BCUC.[55]

130. The submissions made by PNG(NE) at Tab Application in the Amended Application, and as supplemented by PNG(NE)'s responses to information requests (Exhibits B-3, B-3-1, B-4, B-5, B-6, B-6-1, and B-7) and by this argument, provide the BCUC with the evidence it requires to find that the cost of service applied for by PNG(NE) for both 2020 and 2021 are just and reasonable having regard to the rate setting standards applicable to the BCUC under sections 59 and 60 of the *Utilities Commission Act*.

20. CONCLUSION

131. Based on the evidence in this proceeding, the rates sought by PNG(NE) for 2020 and 2021 are supported by sound forecasting methods and are required so that PNG(NE) may recover the costs of serving FSJ/DC and TR customers. PNG(NE) therefore submits that the approvals sought are just and reasonable and in the public interest and should be granted.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Dated at Vancouver, British Columbia this 6th day of July 2020.

PACIFIC NORTHERN GAS (N.E.) LTD.

Original on file signed by:

Gordon Doyle
Vice President, Regulatory Affairs, Legal & Gas Supply

[55] BCUC Order G-99-06, Reasons for Decision