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Pacific Northern Gas (N.E.) Ltd.

2020–2021 Revenue Requirements Application

for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions

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Decision
and Order G-263-20

October 21, 2020

Before:
A. K. Fung, QC, Panel Chair
C. Brewer, Commissioner
M. Kresivo, QC, Commissioner

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Executive summary

Pacific Northern Gas (N.E.) Ltd. [PNG(NE)] operates a natural gas processing plant and natural gas distribution systems in northeastern British Columbia providing service to approximately 21,500 natural gas customers. It is a wholly owned subsidiary of Pacific Northern Gas Ltd., which in turn is a wholly owned subsidiary of TriSummit Utilities Inc.

On February 28, 2020, PNG(NE) filed its 2020-2021 Revenue Requirements Application requesting approval of permanent 2020 and 2021 delivery rates for all rate classes, in addition to other approvals sought. The permanent delivery rates requested for approval in the Application include the following:

Rate Class	Fort St. John		Dawson Creek		Tumbler Ridge	
	2020	**2021**	**2020**	**2021**	**2020**	**2021**
Residential	$5.161/GJ	$5.735/GJ	$4.963/GJ	$5.537/GJ	$10.774/GJ	$11.154/GJ
Small Commercial	$3.963/GJ	$4.348/GJ	$3.426/GJ	$3.811/GJ	$8.497/GJ	$8.775/GJ

PNG(NE) also applies for approval of a permanent Rate Stabilization Adjustment Mechanism (RSAM) rate rider as follows:

- Fort St John / Dawson Creek: credit of $0.022/GJ and $0.012/GJ for the effective January 1, 2020 and January 1, 2021, respectively.
- Tumbler Ridge: credit of $0.923/GJ and $0.406/GJ for the effective January 1, 2020 and January 1, 2021, respectively.

The Panel established a public hearing, including public notice, intervener registration, BCUC and Intervener information requests and written argument. The British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and Tenants Resource and Advisory Centre participated as the sole intervener.

PNG(NE) applied for several adjustments to its 2020 and 2021 revenue requirements during the regulatory process, which are summarized in PNG(NE)'s Final Argument[1] and Appendix A to this decision.

There are several factors that contribute to increases to PNG(NE)'s 2020 and 2021 costs that were identified during the public hearing, including pipeline integrity management activities, IT project costs and shared corporate services cost allocation from PNG's parent company, TriSummit Utilities Inc. After a review of the evidence and argument, the Panel found the Test Period costs associated with these items to be reasonable. The Panel approves the 2020 and 2021 delivery rates and RSAM rate rider filed in the Application on a permanent basis, subject to the adjustments identified by PNG(NE) during the regulatory process and to the directives and determinations in this decision.

In addition, PNG(NE) is directed to file an annual report on significant capital expenditures by April 30 each year and provide specific items in its next revenue requirements application, including information regarding pipeline integrity management activities and details of any cost savings associated with various IT projects.

[1] PNG(NE) Final Argument, pp. 13–14.

1.0 Introduction

1.1 Nature of Application

The purpose of this proceeding is to review the 2020–2021 revenue requirements application (RRA) Pacific Northern Gas (N.E.) Ltd. [PNG(NE)] filed on behalf of its Fort St. John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) Divisions, for approval by the British Columbia Utilities Commission (BCUC) pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA). PNG(NE) maintains separate rate schedules for both the FSJ/DC and the TR Divisions.[2] This decision discusses the approvals sought and issues raised by that application.

In a separate but related proceeding, the BCUC reviewed the RRA brought by PNG(NE)'s parent, Pacific Northern Gas Ltd. (PNG), on behalf of its PNG-West Division (PNG-West) for the same period. The BCUC issued its final Order G-255-20 and accompanying decision on the PNG-West 2020-2021 RRA on October 14, 2020 (PNG-West Decision).

1.2 Background

PNG(NE) operates a natural gas processing plant and natural gas distribution systems in northeastern British Columbia providing service to approximately 21,500 natural gas customers in Fort St John, Dawson Creek, and Tumbler Ridge). It is a wholly owned subsidiary of PNG, which in turn is a wholly-owned subsidiary of TriSummit Utilities Inc. (TSU). PNG also has a western division, PNG-West, which is the owner and operator of a natural gas transmission and distribution system located in the west central part of British Columbia commencing just north of Prince George at Summit Lake and extending west to Kitimat and Prince Rupert. Along this corridor, PNG-West serves 20,400 natural gas customers with an additional 130 propane customers being served in the community of Granisle, BC.[3] The PNG(NE) and PNG-West natural gas pipeline systems are illustrated in Figure 1.[4]

Figure 1: PNG System Map
PNG-West Division and PNG(NE)

2 Exhibit B-2 (FSJ/DC), Section 1.1, p. 2, Exhibit B-2 (TR), Section 1.1, p. 2.
3 Ibid.
4 Ibid., p. 3.

On November 29, 2019, PNG(NE) filed its 2020–2021 RRA with the BCUC for the FSJ/DC and TR Divisions seeking approval to amend its delivery rates and Revenue Stabilization Adjustment Mechanism (RSAM) on an interim and refundable/recoverable basis, effective January 1, 2020 (Original Application). PNG(NE)'s fiscal years 2020 and 2021 are referred to as the "Test Period".

By Order G-331-19, the Panel approved, amongst other things, the following, effective January 1, 2020:

- for the FSJ/DC Division, interim delivery rates of $5.182/GJ for FSJ residential service, $4.984/GJ for DC residential service; $3.977/GJ for FSJ small commercial service; and $3.440/GJ for DC small commercial service. The Panel also approved a reduction to the RSAM rate rider applicable to residential and small commercial customers from $0.059/GJ to a credit rider of $0.081/GJ.
- for the TR Division, interim delivery rates of $10.887/GJ for TR residential service; and $8.579/GJ for TR small commercial service. The Panel also approved a reduction in the RSAM rate rider applicable to residential and small commercial customers from $0.049/GJ to a credit rider of $0.947/GJ.

On February 28, 2020, PNG(NE) filed an amended application to support its request for approval of rates on a permanent basis. The amended application generally includes all of the Original Application, with revisions such as amended demand forecasts which take into consideration the effects of 2019 actual deliveries, updated customer count and cost forecasts, as well as the impact of 2019 actual operating results on rate-base items.[5] From this point forward, the "Application" refers to PNG(NE)'s amended application.

1.3 Regulatory Process and Participants

By Order G-331-19, the BCUC established a regulatory timetable and a written public hearing process for the review of the Application. The timetable included intervener registration, filing an amended application and two rounds of BCUC and intervener information requests (IRs).

The British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and Tenants Resource and Advisory Centre (BCOAPO et al.) participated as the sole intervener. One interested party registered. No letters of comment were received.

By Order G-96-20, the BCUC established the remainder of the regulatory process which included written final and reply arguments.

By letter dated June 10, 2020, the Panel indicated specific factors it considered helpful for the parties to discuss as part of their final arguments.

On June 16, 2020, PNG(NE) filed an evidentiary update addressing an error that pertains to the modelling and calculation of the income tax impact of certain IT-related capital additions and that impacts rates in the Test Period. By Order G-159-20, the BCUC amended the regulatory timetable to include BCUC and intervener IRs on the evidentiary update, and revised dates for written intervener final and PNG(NE) reply arguments.

[5] Exhibit B-2 (FSJ/DC), p. 1, Exhibit B-2 (TR), p. 1.

1.4 Approvals Sought

PNG(NE) included its approvals sought in the Application[6] and subsequently identified several adjustments to its 2020-2021 revenue requirements and resulting delivery rates during the regulatory process, which are summarized in PNG(NE)'s Final Argument[7] and Appendix A to this decision. PNG(NE) summarizes the final approvals sought in its Final Argument as follows:

FSJ/DC Division: [8]

1. Approval on a permanent basis, effective January 1, 2020, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes to the following rate classes, amongst others:[9]

   - A $0.528/GJ (11.4 percent) increase from $4.633/GJ to $5.161/GJ for FSJ Residential service and a $0.528/GJ (11.9 percent) increase from $4.435/GJ to $4.963/GJ for DC Residential service; and
   - A $0.354/GJ (9.8 percent) increase from $3.609/GJ to $3.963/GJ for FSJ Small Commercial service and a $0.354/GJ (11.5 percent) increase from $3.072/GJ to $3.426/GJ for DC Small Commercial service.

   PNG(NE) is also seeking approval effective January 1, 2020, to reduce the RSAM rate rider applicable to Residential and Small Commercial customers on a permanent basis from a debit of $0.059/GJ to a credit of $0.022/GJ.[10]

   A summary of the revenue deficiencies and resultant delivery rate changes for all rate classes for the PNG(NE) FSJ/DC Division is provided in Appendix B to this decision.

2 Approval on a permanent basis, effective January 1, 2021, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes to the following rate classes, amongst others:[11]

   - A $0.574/GJ (11.1 percent) increase from $5.161/GJ to $5.735/GJ for FSJ Residential service and a $0.574/GJ (11.6 percent) increase from $4.963/GJ to $5.537/GJ for DC Residential service; and
   - A $0.385/GJ (9.7 percent) increase from $3.963/GJ to $4.348/GJ for FSJ Small Commercial service and a $0.385/GJ (11.2 percent) increase from $3.426/GJ to $3.811/GJ for DC Small Commercial service.

   PNG(NE) is also seeking approval effective January 1, 2021, to reduce the credit RSAM rate rider applicable to Residential and Small Commercial customers on a permanent basis from a credit of $0.022/GJ to a credit of $0.012/GJ.[12]

   A summary of the revenue deficiencies and resultant delivery rate changes for all rate classes for the PNG(NE) FSJ/DC Division is provided in Appendix B to this decision.

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[6] Exhibit B-2 (FSJ/DC), Section 1.5, pp. 10-11; Exhibit B-2 (TR), Section 1.5, pp. 10-11.
[7] PNG(NE) Final Argument, pp. 13–14.
[8] Ibid., Section 3.1, pp. 4-6.
[9] Exhibit B-2 (FSJ/DC), Section 1.4, p. 7, Table 2; Tab 6, p. 8.
[10]Ibid., Tab 6, pp. 1-4.
[11] Ibid., Section 1.4, p. 8, Table 3, Tab 6, p. 28.
[12] Ibid., Tab 6, pp. 21-24.

3 Approval of PNG(NE)'s proposal to utilize a short-term interest bearing deferral account in 2020 to levelize the impact of the combined net revenue deficiencies for 2020 and 2021 to be fully amortized in 2021.[13]

4 Approval of the changes and additions to PNG(NE)'s deferral accounts and amortization expenses for 2020 and 2021, including approval to create the Accelerated Capital Cost Allowance (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.[14]

5 Approval to recover shared services charged by PNG to PNG(NE) for 2020 and 2021 using the cost allocation and recovery methodology approved by Order G-114-13.[15] The shared services costs allocated to PNG(NE) includes the Shared Corporate Services Costs allocated to PNG from its parent, TSU.

6 Approval to create a new interest bearing deferral account to record a portion of the Shared Corporate Services Costs allocated to PNG from its parent, TSU, not recovered in customer rates in test year 2020 or test year 2021, to be amortized at a future date further to BCUC approval.[16]

7 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 years 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.[17]

8 Approval of the capital reporting process proposed by PNG(NE) in response to directive 5 of BCUC Order G-164-18A.[18]

9. 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.[19]

TR Division:[20]

1. Approval on a permanent basis, effective January 1, 2020, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes to the following rate classes, amongst others:[21]
    - A $0.339/GJ (3.2 percent) increase from $10.435/GJ to $10.774/GJ for Residential service;
    - A $0.248/GJ (3.0 percent) increase from $8.249/GJ to $8.497/GJ for Small Commercial service; and

   PNG(NE) is also seeking approval effective January 1, 2020, to reduce the RSAM rate rider applicable to Residential and Small Commercial customers on a permanent basis from $0.049/GJ to a credit of $0.923/GJ.[22]

[13]Ibid., Section 1.3, p. 6.
[14]Ibid., Section 2.10, pp. 56-60, Tab 2, pp. 12-15.
[15]Ibid., Section 2.6, pp. 45-52.
Ibid., Section 2.5.8, pp. 42-44.
[17] Exhibit B-2 (FSJ/DC), Section 2.2.3, p. 28.
[18]Ibid., Section 3.4.1.1, pp. 113-117; Final Argument, Section 17.1, pp. 37-38.
[19]Ibid., Section 3.4.1.4, pp. 120-125; Final Argument, Section 17.2, pp. 38-39.
[20] PNG(NE) Final Argument, Section 3.2, pp. 6-7.
[21] Exhibit B-2 (TR), Section 1.4, p. 8, Table 2; Tab 6, p. 4.
[22] Ibid., Tab 6, p. 1.

A summary of the revenue deficiencies and resultant delivery rate changes for all rate classes for the PNG(NE) TR Division is provided in Appendix B to this decision.

2. Approval on a permanent basis, effective January 1, 2021, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes to the following rate classes, amongst others: [23]

   - A $0.380/GJ (3.5 percent) increase from $10.774/GJ to $11.154/GJ for Residential service;
   - A $0.279/GJ (3.3 percent) increase from $8.497/GJ to $8.775/GJ for Small Commercial service; and

   PNG(NE) is also seeking approval effective January 1, 2021, to increase the RSAM rate rider applicable to Residential and Small Commercial customers on a permanent basis from a credit of $0.923/GJ to a credit of $0.406/GJ.[24]

   A summary of the revenue deficiencies and resultant delivery rate changes for all rate classes for the PNG(NE) TR Division is provided in Appendix B to this decision.

3. Approval of PNG(NE)'s proposal 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.[25]

4. Approval of the changes and additions to PNG(NE)'s deferral accounts and amortization expenses for 2020 and 2021 including:[26]

   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.

5. Approval to recover shared services charged by PNG to PNG(NE) for 2020 and 2021 using the cost allocation and recovery methodology approved by Order G-114-13.[27] The shared services costs allocated to PNG(NE) includes the Shared Corporate Services Costs allocated to PNG from its parent, TSU.

6. Approval to create a new interest bearing deferral account to record a portion of the Shared Corporate Services Costs allocated to PNG from its parent, TSU, not recovered in customer rates in test year 2020 or test year 2021, to be amortized at a future date further to BCUC approval.[28]

7. Approval to continue the UAF volume deferral account on the basis that the UAF volume forecast for test years 2020 and 2021 is 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

[23] Ibid., Section 1.4, p. 8, Table 2; Tab 6, p. 14.
[24] Ibid., Tab 6, p. 12.
[25] Ibid., Section 1.3, p. 6.
[26] Ibid., Section 2.10, pp. 54-57; Tab 2, pp. 7-11.
[27] Ibid., Section 2.6, pp. 43-50.
[28] Ibid., Section 2.5.8, pp. 40-42.

application with the BCUC to obtain approval to record UAF losses above 1.0 percent in this deferral account. [29]

8. Approval of the capital reporting process proposed by PNG(NE) in response to directive 5 of BCUC Order G-164-18A.[30]

9. 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.[31]

1.5 Decision Framework

In this decision, the Panel specifically addresses the following:

Section 2.0 reviews general issues that are addressed in the PNG-West Decision that also apply to PNG(NE). These include pipeline system integrity, IT projects, the automotive cost allocation methodology, forecast interest rates applied to short-term and long-term debt, the Shared Corporate Services Costs allocated to PNG from its parent, TSU (TSU Shared Corporate Services Costs), reporting on significant capital projects, impact of the COVID-19 pandemic, and PNG-West and PNG(NE) rate design.

Section 3.0 addresses issues related to the cost of service including those associated with operating, maintenance, administrative and general expenses, rate base, including proposed capital expenditures, and deferral accounts including the proposed rate deferral mechanism, Accelerated CCA deferral account and elimination of the Studies deferral account.

Section 4.0 focuses on proposed delivery rate changes.

2.0 Common Issues Addressed in the PNG-West Decision

The BCUC discussed and addressed the following issues which are common to both PNG-West and PNG(NE) in some detail within the PNG-West Decision:

- Pipeline System Integrity Management;
- IT Projects;
- Automotive Cost Allocation;
- Interest Rates;
- TSU Shared Corporate Services Costs;
- Reporting on Significant Capital Projects;
- Impact of COVID-19 Pandemic; and
- PNG-West and PNG(NE) Rate Design.

[29]Ibid., Section 2.2.3, p. 27.
[30]Ibid., Section 3.4.1.1, pp. 90-94; Final Argument, Section 17.1, pp. 37-38.
[31]Ibid., Section 3.4.1.4, pp. 97-102; Ibid., Section 17.2, pp. 38-39.

The Panel considers these issues in relation to the PNG(NE) divisions in this decision. It is best read in conjunction with the PNG-West Decision for greater detail and clarity.

2.1 Cost of Service Issues

The common issues of pipeline system integrity, IT projects, the automotive cost allocation methodology, forecast interest rates, and the TSU Shared Corporate Services Costs all impact PNG(NE)'s cost of service and are discussed below.

2.1.1 Pipeline System Integrity Management

PNG(NE) submits that increases to the cost of service for the Test Period are in part due to increases in operating costs necessary to ensure compliance with pipeline integrity related code, standards and regulations.[32] PNG(NE) further submits that the following pipeline integrity related factors have led to increases in operating costs:[33]

1) Heightened stakeholder, regulator and public focus;
2) Aging infrastructure; and
3) Deferred pipeline maintenance.

PNG(NE) states in its Application and IR responses that its pipeline assets are attracting increased attention from the BC Oil and Gas Commission (BC OGC). This increased attention has led to mandated pipeline integrity activities, such as segment-by-segment risk assessments and Integrity Management Program (IMP) audits.[34] PNG(NE) submits that improvements to its integrity programs have been made in recent years; however, the segment-by-segment risk assessments have not been completed.[35] Beginning in January 2020, quarterly updates are being provided by PNG(NE) to the BC OGC regarding progress towards completion of the segment-by-segment risk assessments. In February 2020, PNG(NE) was notified by the BC OGC that the PNG(NE) IMP had been selected for a full and formal audit.[36]

At the time the Application was filed, these pipeline integrity activities were still in the developmental stage. As a result, the Application did not include costs associated with future directives stemming from BC OGC assessments and audits.[37] PNG(NE) has since incorporated the updated BC OGC related costs in its final regulatory schedule submissions. The BC OGC mandated activities result in revenue requirement increases of $17,000 in 2020 and $38,000 in 2021.[38]

Positions of the Parties

BCOAPO agrees that pipeline integrity is of paramount importance and accepts PNG(NE)'s integrity spending proposals.[39]

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32 Final Argument, para. 17.
33 Exhibit B-3, BCUC IR 6.2.
34 Exhibit B-6, BCUC 68.4.
35 Ibid., BCUC IR 68.3 – Attachment BCUC 68.3b.
36 Exhibit B-3, BCUC IR 6.3; Exhibit B-6, BCUC IR 68.3 – Attachments BCUC 68.3c.
37 Exhibit B-6, BCUC 68.4.
38 PNG(NE) Final Argument, para 32.
39 BCOAPO Final Argument, p. 7.

Panel Determination

The Panel acknowledges that maintaining the integrity of the PNG(NE) natural gas delivery infrastructure is a driver for increased operating costs during the Test Period. The Panel has concerns regarding the potentially increasing pipeline integrity related costs. The Panel urges PNG(NE) to continue to include in future revenue requirements detailed discussions regarding the need for integrity management activities and assessments of cost-effective means for addressing pipeline integrity management issues.

The Panel notes that responses to BC OGC mandated activities are currently still in a developmental stage. These activities include the pipeline segment-by-segment risk assessment and the IMP audit. **Accordingly, PNG(NE) is directed to file as part of the next RRA a progress update regarding the pipeline segment-by-segment risk assessment and the IMP audit. The progress update should include the current status of each activity, a schedule to complete the requirements for each activity and a summary of recommendations resulting from completed activities. The progress update should also include relevant information presented by PNG(NE) to the BC OGC to date, including the IMP Overview Presentations submitted as part of the IMP Audit and the Risk Assessment Corrective Action Plan quarterly progress reports.**

2.1.2 IT Projects

In the PNG-West Decision the BCUC accepted the project costs for the Test Period , including the cost allocations from PNG-West to both FSJ/DC and TR Divisions, for the following IT projects:

- JD Edwards (JDE) Enterprise Resource Planning (ERP) accounting system;
- Ultimate Software (UltiPro) human resource information system (HRIS);
- Customer information services (CIS) system;
- Microsoft 365 transition;
- Management of change;
- Synergi Gas hydraulic modelling software;
- Geographical information system (GIS);
- Asset record modernization (ARM); and
- Maximo asset management system.

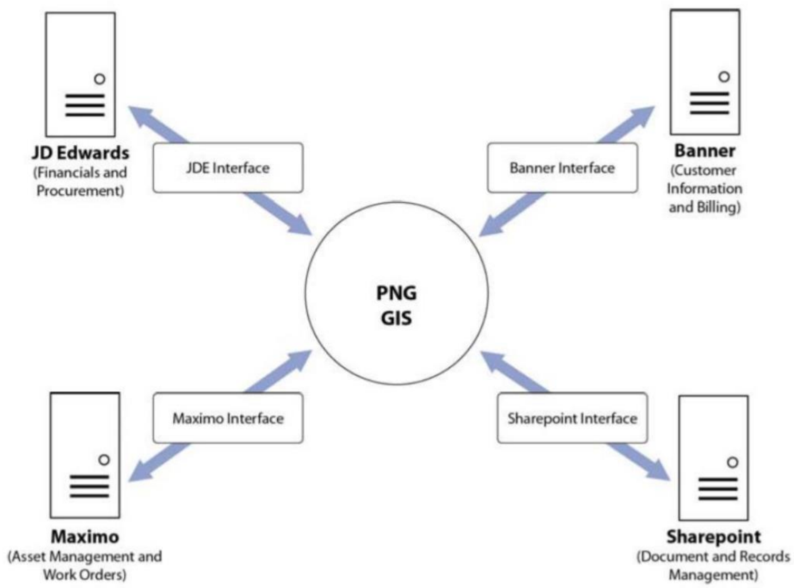
PNG allocates IT project costs to PNG-West and the PNG(NE) divisions using specific allocators for each IT project from the cost allocation methodology approved by the BCUC in Order G-114-13, including the composite average allocator, employee count and customer count allocators. The composite average allocator comprises customer count, employee count and rate base. [40]

The BCUC has included a detailed discussion of each of the above IT projects and the associated costs and benefits in the PNG-West Decision, which applies also to PNG(NE).

[40] Exhibit B-3, BCUC IR 18.1.1, 16.2.

In the PNG-West 2018-2019 RRA proceeding PNG-West provided a network architecture diagram which shows the relationship between the various IT projects listed above involving all of the PNG divisions (i.e. PNG-West, FSJ/DC and TR).[41]

Figure 2: Network Architecture Diagram



The Maximo system will be configured to directly interface with the CIS system.[42] PNG expects to realize cost savings related to the Synergi Gas, GIS and ARM systems, but states these benefits cannot yet be quantified.[43] PNG does not, however, anticipate any annual cost savings associated with the new JDE and HRIS systems nor Microsoft 365.[44] Further, PNG(NE) notes that the Maximo program is unlikely to deliver any cost savings in the short or medium term but will result in adequate asset condition information that will allow development of a risk-based inspection process, which may deliver cost savings.[45] The management of change system update is required to meet requirements of the BC OGC and no cost savings have been provided for this system.[46] However, in the PNG-West Decision, the BCUC discusses the need for each of these projects and the qualitative and operational benefits associated with each project.

Through joint implementation of the new CIS system, PNG anticipates savings for bill print and presentment of approximately $100,000 annually. PNG(NE) has reflected its allocated share of savings in its forecast of operating costs for test year 2021. PNG(NE) also expects to realize further financial benefits from the new CIS system commencing in test year 2022 after the new CIS system has been fully implemented. This is due to fewer internal resources being required with the new system, specifically a reduction of one headcount in the CIS technical support group,[47] resulting in anticipated annual cost savings in the range of $46,000 to $64,000 for the FSJ/DC Division and $3,000 to $4,200 for the TR Division.[48] However, PNG(NE) anticipates that cost savings on a

[41] PNG-West 2018-2019 RRA proceeding, Exhibit B-3, BCUC IR 46.
Series, Attachment BCUC 1.46a, p. 24.
[42] Ibid., BCUC IR 79.2.
[43] Exhibit B-3, BCUC IR 44.4; PNG-West 2020-2021 RRA proceeding, Exhibit B-2, p. 161; Exhibit B-3, BCUC IR 84.1.
[44] Exhibit B-3, BCUC IR 18.2; Exhibit B-6, BCUC IR 80.7.
[45] Ibid., BCUC IR 17.1.
[46] Ibid., BCUC IR 35.2.
[47] Ibid., BCUC IR 10.2.
[48] Exhibit B-6, BCUC IR 72.4.

net basis from the new CIS system will not be realized until 2032 onwards, as a result of the overall reduction in cost of service being more than offset by the higher depreciation charges from TSU for the first ten years of the CIS system's expected life.[49]

Positions of the Parties

BCOAPO does not take a position on PNG(NE)'s proposal for any of the IT projects.

Panel Determination

The Panel accepts the 2020 and 2021 capital, operating and administrative expenditures associated with the above-noted IT projects, including the allocation of IT project costs to the FSJ/DC and TR Divisions, subject to the adjustments identified by PNG(NE) during the regulatory process and summarized in Appendix A to this decision.

The need for each project has been supported by the evidence in this proceeding. Consistent with the PNG-West Decision, the Panel accepts the Test Period IT expenditures for these new systems. In addition, the Panel recognizes that these projects offer opportunities for PNG(NE) for enhanced business processes, better customer service and internal staffing efficiencies as well as additional operational benefits yet to be identified upon project completion.

With respect to the methodology for allocating IT project costs between PNG-West and the PNG(NE) divisions, the Panel notes that PNG has used specific allocators from the methodology previously approved by the BCUC by Order G-114-13. The allocator used for each project has been selected based on the type of IT system and the nature of the benefits that the system provides. In the PNG-West decision, the Panel found the allocation of IT project costs between PNG-West and the PNG(NE) divisions to be reasonable.

However, consistent with the PNG-West Decision, the Panel is concerned about the anticipated financial benefits and the timing of any cost savings associated with these new systems. PNG(NE) does not anticipate any annual cost savings associated with the new JDE, HRIS and management of change systems nor Microsoft 365. Nonetheless, the evidence is sufficient to satisfy the Panel as to the need for these projects.

Further, PNG(NE) has provided cost savings associated with the CIS system, including the bill print and presentment savings achieved from the supplier through joint implementation and the reduction of one headcount for technical support. However, the net expected cost savings from the new CIS system will not be realized until 2032 onwards, due to depreciation charges from TSU for the first ten years of the CIS system's expected life offsetting the cost savings. Additionally, there are potential cost savings and cost avoidance opportunities associated with the Synergi Gas, GIS, ARM and Maximo projects which PNG(NE) has yet to quantify. These cost savings should be quantified, and any cost savings appropriately applied to PNG(NE)'s future revenue requirements once the projects have been implemented. **Accordingly, the Panel directs PNG(NE) in the next RRA to file a report detailing the following for both the FSJ/DC and TR Divisions:**

- **Any change(s) in annual operating and administrative costs as a result of implementing each IT project, including the amount and details on what the change(s) relate to, specifying any cost savings realized as compared to the existing processes;**

[49] Ibid., BCUC IR 72.3.

- **The actual versus forecast 2020 and 2021 IT project costs, including a breakdown between capital expenditures and operating / administrative expenses and detailed explanations for any significant variances for each IT project;**
- **An update on the timing schedule for each IT project, as necessary; and**
- **The net annual cost savings for the CIS, Synergi Gas, GIS, ARM and Maximo projects, specifying the annual cost savings achieved and the annual offsetting costs incurred, including operating and administrative expenses and the revenue requirement impact of the capital additions (i.e. return on equity and debt and depreciation charges).**

2.1.3 Automotive Cost Allocation

In PNG(NE)'s 2018-2019 RRA Reasons for Decision accompanying Order G-164-18A (PNG(NE) 2018-2019 Decision)[50] the BCUC directed PNG(NE) to review and assess the effectiveness of the existing automotive cost allocation methodology. Pursuant to that directive, PNG(NE) has presented its analysis and evaluation of its existing approach to the allocation of automotive costs in this Application. This includes 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 PNG(NE) divisions, including: [51]

1) Basing the Test Period forecast consolidated automotive cost pool on the actual costs of the prior year with a 2 percent provision for inflation;
2) Continuing 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;
3) Continuing to apply the current administrative convention of allocating actual automotive costs to capital, whereby a 15 percent factor is applied to capital labour costs and capitalized; and
4) Establishing the Test Period forecast operating automotive cost pool as the consolidated automotive cost pool less amounts identified as being attributable to capital and allocating 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.

PNG(NE) submits that, while there is uncertainty inherent in any forecast methodology, the proposed cost pool forecast methodology and allocation will reduce the magnitude of the over/under allocation of automotive costs between cost categories and between divisions.[52]

The proposed modification to PNG(NE)'s automotive cost allocation methodology as well as methodology for forecasting the consolidated pool of automotive costs is reflected in the Test Period and has resulted in a lower allocation of consolidated automotive costs to the FSJ/DC and TR Divisions.[53] For test years 2020 and 2021 operating automotive costs allocated to PNG-West are $515,000 and $520,000, respectively, as compared to $469,000 allocated to PNG-West in the PNG-West 2018-2019 RRA Reasons for Decision (PNG-West 2018-2019 Decision). This results in a correspondingly lower allocation of automotive costs to PNG(NE)'s FSJ/DC and TR Divisions in test years 2020 and 2021. [54]

[50] Order G-164-18A and accompanying Decision.
[51] PNG(NE) Final Argument, Section 17.2, pp. 38-39.
[52] Ibid.
[53] Exhibit B-2 (FSJ/DC), Section 2.3, p. 31; Exhibit B-2 (TR), Section 2.3, p. 29.
[54] Ibid.; Ibid., p. 31; PNG-West Exhibit B-2, Section 2.3.5, p. 42.

Readers can find a full discussion on this topic in the PNG-West Decision.[55]

Position of the Parties

BCOAPO does not take a position on PNG(NE)'s proposal for automotive cost allocation methodology.

Panel Determination

The Panel acknowledges that PNG(NE) has satisfied the direction pursuant to Order G-164-18A and approves PNG(NE)'s automotive cost forecast for the Test Period, which is based on the revised allocation methodology. Similar to PNG-West, the Panel encourages PNG(NE) to continue to review and assess the effectiveness of the revised automotive cost allocation methodology with respect to variances in forecast and actual expense allocations and recommend revisions in future RRAs as necessary.

2.1.4 Interest Rates

In establishing forecast short-term and long-term interest expense, PNG(NE) uses the 90 day treasury bill rates from the Bank of Montreal's (BMO) November 22, 2019 forecast (BMO November 2019 Forecast) for the underlying prime rate for operating line borrowings (short-term debt) and the revolving term facilities (long-term debt). However, due to changing economic conditions, BMO published a revised forecast dated March 27, 2020 (BMO March 2020 Forecast), which indicates that the forecast 90-day treasury bill rate for 2020 declined from 1.6625 percent to 0.4875 percent and also includes a forecast for 2021 of 0.20 percent.[56] Using BMO's March 2020 Forecast would reduce PNG(NE)'s forecast 2020 and 2021 short-term and long-term debt interest rates and corresponding Test Period interest costs.[57] For all PNG(NE) divisions, this results in an estimated 1.2 percent rate reduction in 2020 and a 1.5 percent to 1.6 percent rate reduction in 2021. The reduction in the average residential annual bill is estimated to be between $6.04 and $8.78 in 2020 and between $9.12 and $12.15 in 2021 for all divisions.

PNG(NE) relies on the short-term and long-term deferral accounts to capture the variances in the actual and forecast debt rates financing costs. Given the current uncertainty in the capital markets, and the inability to be able to forecast what terms for the renewal of the operating facility may be provided in May 2021, PNG(NE) proposes to rely on these deferral accounts to capture any differences in financing costs for test years 2020 and 2021.[58]

Positions of the Parties

BCOAPO contends that the most recent forecast should be used in determining the interest costs to be recovered and accordingly, the BMO March 2020 Forecast should be the basis for the Test Period forecast.[59] BCOAPO acknowledges that PNG(NE) has a deferral account for variances between forecast and actual interest rates but observes that the shareholder is held harmless "while ratepayers are ultimately 100% responsible for all variances in interest rates."

[55] PNG-West Decision, Section 3.4, pp. 31-33.
[56] Exhibit B-3, BCUC IR 46.1.
[57] Exhibit B-3, BCUC IR 46.1; Exhibit B-6, BCUC IR 90.1.
[58] Exhibit B-2 (FSJ/DC), Section 2.14.1, p. 83; Exhibit B-2 (TR), Section 2.14.1, p. 68; Exhibit B-3, BCUC IR 46.1.
[59] BCOAPO Written Argument, p. 7.

In its Reply Argument, PNG(NE) submits that, although it believes the interest rate deferral account mechanism in place will achieve a comparable result, it is amenable to adopting BCOAPO's recommendation to reflect the BMO March 2020 Forecast interest rates in the regulatory schedules and in the determination of final approved rates.

PNG(NE) is critical of BCOAPO's argument that the deferral accounts hold "the shareholder harmless while ratepayers are ultimately 100% responsible for all variances in interest rates." It notes that the protections provided by the deferral accounts are not one-way and are not favourable solely to the shareholder, as the mechanism captures both negative and positive variances in interest expense.[60]

Panel Determination

The Panel directs PNG(NE) to update the interest rate forecasts in its final regulatory schedules to reflect the BMO March 2020 Forecast interest rates.

The Panel recognizes that PNG(NE) has short-term and long-term interest deferral accounts to address the impact of differences between the forecast and actual interest rates during the Test Period. However, the Panel agrees with BCOAPO regarding the advantages of using the most recent information available in developing forecasts. The Panel is persuaded that applying the more recent forecast of interest rates is warranted and agrees that PNG(NE) should adopt the BCOAPO's recommendation.

2.1.5 TSU Shared Corporate Services Costs

PNG(NE) seeks approval to recover in customer rates its portion of the Shared Corporate Services Costs allocated to PNG by its parent, TSU.[61] As mentioned above, PNG(NE) is a wholly owned subsidiary of PNG, which in turn is a wholly-owned subsidiary of TSU. TSU provides corporate services on behalf of PNG and allocates a portion of its costs to PNG (referred to as TSU Shared Corporate Services Costs) and its other subsidiaries using the Modified Massachusetts Formula. This methodology is consistent with standard industry practice and does not differ from the allocation methodology used in prior years.[62] PNG in turn allocates costs, including the TSU Shared Corporate Services Costs, to PNG(NE) using the cost allocation methodology approved by Order G-114-13.[63]

The cost allocation to the FSJ/DC Division is $634,000 and $624,000 for test years 2020 and 2021, respectively; and the cost allocation to the TR Division is $41,000 and $42,000 for test years 2020 and 2021, respectively. This is an increase from prior test periods, which is discussed further in the History section below. The consolidated cost allocation from TSU to PNG is $1.835 million in 2020 and $1.872 million in 2021.[64]

PNG(NE) also seeks approval to record a portion of the above-noted cost allocation in a deferral account for each of the divisions (FSJ/DC and TR) in order to mitigate the impact on customer rates, with the disposition of

[60] PNG(NE) Written Reply Argument, Section 2.3, p. 5, paragraph 17.
[61] Exhibit B-2 (FSJ/DC), Section 2.5.8, p. 43; Exhibit B-2 (TR), Section 2.5.8, p. 40.
[62] PNG-West, Exhibit B-3, BCUC IR 32.1.
[63] Exhibit B-2, Section 2.11, p. 81.
[64] Exhibit B-2 (FSJ/DC), Section 2.5.8, p. 43, Table 23; Exhibit B-2 (TR), Section 2.5.8, p. 41, Table 21.

the deferral account to be determined at future date. PNG(NE) requests approval to record the following in each of the TSU Shared Corporate Services Costs deferral accounts:[65]

- For the FSJ/DC Division, $377,000 and $374,000 of the TSU Shared Corporate Services Costs for test years 2020 and 2021, respectively; and
- For the TR Division, $24,000 and $25,000 of the TSU Shared Corporate Services Costs for test years 2020 and 2021, respectively.

In the sections that follow, the Panel provides some historical context for the Shared Corporate Services Costs allocated to PNG by its parent, TSU, and discusses the determinations made as part of the PNG-West Decision. Based on the PNG-West Decision, the Panel addresses the TSU Shared Corporate Services Costs to be recovered by PNG(NE)'s divisions and subsequently the request for approval of deferral account treatment for the FSJ/DC and TR Divisions.

History

In December 2011, PNG became a wholly owned subsidiary of AltaGas Utility Holdings (Pacific) Inc., a 100 percent owned subsidiary of AltaGas Ltd. (AltaGas). PNG transitioned from being a standalone public company to a wholly owned subsidiary of a public company. After the acquisition, PNG no longer needed to directly incur expenses to maintain its public reporting status. Instead, these costs were incurred by AltaGas on behalf of PNG and its other subsidiaries, in addition to other costs such as tax consultancy fees and certain insurance costs. AltaGas allocated a portion of its Shared Corporate Services Costs to PNG and its other subsidiaries using the Modified Massachusetts Formula.[66] Following a corporate re-organization in 2018 and a shareholder approved purchase by new owners that completed in March 2020, PNG became a wholly owned subsidiary of TSU.[67] Please see the PNG-West Decision for details on the corporate re-organization and purchase transaction.

In prior years, PNG-West and PNG(NE) only sought and received approval to recover a portion of the total Shared Corporate Services Costs in customer rates, noting that it ultimately expected to seek recovery of all costs allocated by its parent as economic circumstances improved.[68] For example in 2019, the forecast and actual consolidated Shared Corporate Services Costs were $1.159 million[69] and $1.777 million, respectively.[70] However in the PNG-West 2018-2019 RRA proceeding, PNG only proposed and was approved to recover $743,000 in customer rates.[71] In 2019, PNG-West allocated $259,000 of the Shared Corporate Services Costs to the FSJ/DC Division and $16,000 to the TR Division.[72]

In the PNG-West Decision, the BCUC approved for PNG-West to recover the full TSU Shared Corporate Services Costs of $1.835 million in 2020 and $1.872 million in 2021. This is discussed further in the sub-sections below.

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[65] Exhibit B-2 (FSJ/DC), Section 2.5.8, p. 43; Exhibit B-2 (TR), Section 2.5.8, p. 41.
[66] Order G-130-12 with reasons for decision, section 7.3, p. 23; PNG 2013 RRA, Exhibit B-1, p. 12.
[67] PNG-West Exhibit B-2, Section 1.1, p. 2; TSU Press Release dated December 19, 2010; TSU Fiscal 2020 Second Quarterly Report, Management's Discussion and Analysis, The Company, p. 2.
[68] PNG-West 2013 RRA, Exhibit B-1, p. 13; PNG-West 2014 RRA, Exhibit B-1, Section 2.5.1, p. 31; PNG-West 2015 RRA, Exhibit B-2, Section 3.1, p. 14; PNG-West 2016-2017 RRA, Exhibit B-1-1, Section 2.5.1, p. 45; PNG-West 2018-2019 RRA, Exhibit B-1-1, Section 2.5.1, p. 44.
[69] The PNG-West 2018-2019 Decision forecast Shared Corporate Services Costs of $1.159 million was established by AltaGas under the assumption that a large gas utility that AltaGas would have a significant impact on reducing the allocation to all its subsidiaries under the MMF formula. [Exhibit B-3, BCUC IR 29.1].
[70] PNG-West 2020-2021 RRA Proceeding, Exhibit B-3, BCUC IR 29.1.
[71] Ibid., Exhibit B-3, BCUC IR 29.1.
[72] Exhibit B-2 (FSJ/DC), Section 2.5.8, p. 43, Table 23; Exhibit B-2 (TR), Section 2.5.8, p. 41, Table 21.

2.1.5.1 Full Recovery of TSU Shared Corporate Services Costs

As noted above, PNG(NE) seeks approval to record its portion of the full TSU Shared Corporate Services Costs. The PNG(NE) portion is higher than that approved for previous test periods, as PNG historically only sought and received approval to recover a portion of the cost allocation in cost of service.

PNG allocates the costs between PNG-West and the PNG(NE) divisions using the cost allocation and recovery methodology approved by the BCUC in Order G-114-13.[73] The cost allocation breakdown between PNG-West and the PNG(NE) divisions from 2019 to 2021 is illustrated in Table 1 below:[74]

Table 1: Cost Allocation between PNG-West and PNG(NE)

Cost Allocation ($000's)	Decision 2019	Test Year 2020	Test Year 2021
PNG-West	468	1,160	1,207
PNG(NE) – FSJ/DC	259	634	624
PNG(NE) – TR	16	41	42
Consolidated	**743**	**1,835**	**1,872**

** The consolidated amount may not total due to rounding; t able prepared by BCUC*

TSU provides services to directly support its wholly owned subsidiaries in a variety of areas, including governance, business oversight, financing, administration, legal, accounting and regulatory.[75] PNG notes that the TSU Shared Corporate Services Costs provide benefits to PNG, which in turn benefit PNG(NE). These include achieving economies of scale, expanding access to capital, sharing expertise and best practices, and having the ability to share the costs associated with the necessary corporate services without incurring the full standalone costs of those services.[76] PNG-West submits that these costs are fair, reasonable and prudently incurred.[77]

PNG(NE) is forecasting low or near zero load growth in the FSJ/DC Division and within the TR Division, apart from a forecast increase in load for the TR's Division only industrial customer, PNG(NE) is otherwise forecasting little or no growth over the Test Period for the region.[78] However, PNG(NE) submits it continues to be very cognizant of the effect on customer rates of increasing the recovery of these charges and believes that with the expected successful outcome of the impending RECAP in PNG-West, it is now appropriate to seek approval of the full amount of the TSU Shared Corporate Services Costs across PNG-West and the PNG(NE) Divisions through the deferral account proposal as set out in the Application.[79] Further, 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 for both customers and its shareholder, full recovery of prudent and reasonable costs incurred is appropriate.[80]

[73] Exhibit B-2 (FSJ/DC), Section 2.6, p. 45; Exhibit B-2 (TR), Section 2.6, p. 43.
[74] Exhibit B-2 (FSJ/DC), Section 2.5.8, p. 43, Table 23; Exhibit B-2 (TR), Section 2.5.8, p. 41, Table 21.
[75] PNG-West, Exhibit B-2, Appendix B, Section 4.1, p. 3.
[76] Ibid., Section 2.5.7.1, p. 63; Exhibit B-3, BCUC IR 30.2, 30.3.
[77] Ibid., Exhibit B-2, Section 2.5.7.1, p. 63.
[78] Exhibit B-3 BCUC IR 15.3.
[79] Ibid., BCUC IR 15.8
[80] PNG(NE) Final Argument, Section 11.1, p. 23.

PNG-West Decision

In the PNG-West Decision, the BCUC approved the full recovery of the Shared Corporate Services Costs allocated in the Test Period to PNG by its parent, TSU. In making its determinations in that proceeding, the BCUC considered the reasonableness of the costs in relation to the benefits they provide to PNG's ratepayers.[81]

The BCUC also reviewed the evidence related to the value of these services and costs for PNG and its ratepayers in order to assess the reasonableness of the full allocation amount. This included two estimates with which to compare the full TSU Shared Corporate Services Costs:

1. Fair Value Estimate: PNG's management prepared a fair value estimate of the 2020 and 2021 Shared Corporate Services Costs, consisting of a summary of the estimated costs PNG would have incurred as standalone pubic company (Fair Value Estimate).[82] KPMG LLP (KPMG) was retained by TSU's predecessor[83] in November 2019 to perform an independent assessment of the Fair Value Estimate and the results are summarized in a report dated February 27, 2020 (KPMG Report).[84]
2. Alternative Cost Estimate: PNG also provided an alternative estimate of $2.678 million for the 2020 costs to operate as a standalone public company, which uses actual 2011 costs as the base. This represents incremental costs that would be incurred by PNG to operate as a standalone public company in 2020, recognizing that there are certain costs already included in PNG's 2020 revenue requirements.[85]

In the PNG-West Decision, the BCUC made the following findings that support the decision to approve the full TSU Shared Corporate Services Costs allocation: [86]

- Some allocation of Shared Corporate Service Costs from PNG's parent, TSU, to PNG is appropriate, considering the services provided by TSU and the benefits achieved by PNG as a result of those services.
- The costs in the Fair Value Estimate appear overstated and are not an acceptable basis upon which to determine the reasonableness of the quantum of PNG's TSU Shared Corporate Services Costs for the Test Period.
- On balance, the Alternative Cost Estimate provides support for the reasonableness of the TSU Shared Corporate Services Costs, even after taking into account several potential adjustments.

Positions of the Parties

BCOAPO does not take issue with PNG(NE)'s portion of the TSU Shared Corporate Services Costs.[87] However, BCOAPO recognizes that the TSU Shared Corporate Services Costs to be recovered are significantly higher than those approved by the BCUC in prior RRAs and submits that the approved amount should be a maximum of the amount approved in PNG(NE) 2018-2019 Decision plus inflation.[88]

PNG(NE) contends that while it has historically only sought and received approval of recovery for a portion of the TSU Shared Corporate Services Costs, it has stated in previous RRAs that it expects to seek full recovery of all

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[81] PNG-West Decision, Section 3.3, pp. 18-31.
[82] PNG-West 2020-2021 RRA Proceeding, Exhibit B-2, Appendix B, Section 4.2, p. 5.
[83] KPMG was retained by ACI, as the KPMG report was issued prior to the change in name from ACI to TSU on March 31, 2020.
[84] PNG-West 2020-2021 RRA Proceeding, Exhibit B-2, Section 2.5.7.1, p. 64.
[85] Ibid., Exhibit B-3, BCUC IR 32.4.
[86] PNG-West Decision, Section 3.3, pp. 19-31.
[87] BCOAPO Final Argument, pp. 9-11.
[88] Ibid., p. 14.

costs allocated by its parent company. Further, PNG(NE) reiterates that the TSU Shared Corporate Services Costs are fair, reasonable and prudently incurred.[89]

Panel Determination

PNG(NE) is approved to record its allocation of the TSU Shared Corporate Services Costs in its Test Period revenue requirements, as follows:

- **FSJ/DC Division – $634,000 in 2020 and $624,000 in 2021; and**
- **TR Division – $41,000 in 2020 and $42,000 in 2021.**

In making its determination, the Panel has considered the benefits the TSU Shared Corporate Services Costs provide to PNG(NE)'s customers. PNG(NE) has put forward evidence regarding the corporate services provided by its parent, TSU, including governance, business oversight, financing, administration, legal, accounting and regulatory services. These services are necessary for both PNG-West and PNG(NE) to maintain their capital structure and access capital. These services are critical for any utility and without TSU, PNG would have to incur costs to acquire these services as a standalone public company, and a portion of the costs would be allocated to PNG(NE). The Panel acknowledges that the services provided by TSU give both direct and indirect benefits to PNG-West and PNG(NE) and their respective customers, including achieving economies of scale, expanding access to capital, and sharing in corporate services costs, benefits that may not be realized as a standalone public entity.

This Panel also refers to the PNG-West Decision, whereby the Panel found that some allocation of TSU Shared Corporate Services Costs from PNG's parent, TSU, to PNG is appropriate, considering the services provided by TSU and the benefits achieved by PNG as a result of those services.

In consideration of the services provided by TSU and the resulting benefits realized by both PNG-West and PNG(NE), the Panel finds that the portion of the TSU Shared Corporate Services Costs, as filed, allocated to PNG(NE) is appropriate. The Panel notes that in the PNG-West Decision the BCUC approved the allocation of the consolidated TSU Shared Corporate Services Costs between PNG-West and the PNG(NE) divisions using the allocation methodology previously approved by BCUC Order G-114-13.

2.1.5.2 TSU Shared Corporate Services Costs Deferral Account

As noted above, PNG(NE) recognizes the recovery of the full TSU Shared Corporate Services Costs will result in an increase in customers' rates. Accordingly, PNG(NE) seeks approval to establish a new interest bearing deferral account to record a portion of the TSU Shared Corporate Services Costs for future recovery as the BCUC may determine.

PNG(NE) is cognizant of the effect on customer rates of increasing the recovery of the TSU Shared Corporate Services Costs.[90] In an effort to reduce the impact on the cost of service over the Test Period, PNG(NE) seeks approval to establish a new interest bearing deferral account to record a portion of the TSU Shared Corporate Services Costs to be amortized at a future date subject to BCUC approval.[91] PNG(NE) notes that although not the

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[89] PNG(NE) Reply Argument, pp. 8-9, para. 27.
[90] Exhibit B-3, BCUC IR 15.8.
[91] Exhibit B-2 (FSJ/DC), Section 2.5.8, p. 43; Exhibit B-2 (TR), Section 2.5.8, p. 41.

preferred alternative, there have been circumstances where deferral accounts have been established without a set amortization start date nor amortization period, recognizing that this approach provides flexibility but also creates intergenerational inequity for customers.[92]

The table below illustrates the full cost allocation, the amount proposed to be recorded in the TSU Shared Corporate Services Costs deferral account and the net amount to be recovered from customers in test years 2020 and 2021 by PNG-West as well as PNG(NE) FSJ/DC and TR Divisions, including the historical information for 2019.[93]

Table 2: PNG(NE) and PNG-West - Cost Allocation, Cost Deferral and Cost of Service Impact

Cost Allocation, Cost Deferral and Cost of Service Impact by Division ($000's)		Decision 2019	Test Year 2020	Test Year 2021
PNG-West	Cost Allocation (as above)	468	1,160	1,207
	Cost Deferral	-	676	700
	Cost of Service Impact	468	484	507
PNG(NE) – FSJ/DC	Cost Allocation (as above)	259	634	624
	Cost Deferral	-	377	374
	Cost of Service Impact	259	255	250
PNG(NE) – TR	Cost Allocation (as above)	16	41	42
	Cost Deferral	-	24	25
	Cost of Service Impact	16	17	17
Consolidated	**Cost Allocation (as above)**	**743**	**1,835**	**1,872**
	Cost Deferral	**-**	**1,078**	**1,099**
	Cost of Service Impact	**743**	**756**	**773**

** Totals may not sum due to rounding; BCUC prepared table based on the references noted.*

The net amount to be recovered in rates on a consolidated basis is approximately equal to an inflationary increase of two percent over the historical amount allowed for recovery in the PNG-West 2018-2019 Decision.[94] The impact to the PNG(NE) divisions varies slightly from the inflationary increase of the consolidated:

- FSJ/DC Division: the proposed amount to be recovered in Test Year 2020 is $255,000, which is $4,000 less than 2019.
- TR Division: the proposed amount to be recovered in Test Year 2020 is $17,000, which is $1,000 more than 2019.

For the FSJ/DC Division, PNG(NE) forecasts low or near zero load growth over the Test Period. Apart from a projected increase in load for its one industrial customer. PNG(NE) is forecasting for the TR Division little or no growth during the Test Period.[95] PNG(NE) submits it will seek approval for the amortization of this deferral account in future years as it adds more customer volume in the system.[96] One of PNG(NE)'s priorities in recent years has been to attract new customers in all service areas but this objective has not been met given the current economic conditions for certain industries in the region.[97] PNG(NE) submits it does not have a proposal for the disposition of the deferral account should additional customer volumes not materialize over the next few

[92] Exhibit B-6, BCUC IR 76.2.
[93] Exhibit B-2 (FSJ/DC), Section 2.5.8, p. 43, Table 23; Exhibit B-2 (TR), Section 2.5.8, p. 41, Table 21.
[94] Exhibit B-2, Section 2.5.1, pp. 50-51, Table 20; Section 2.5.7.1, p. 63-64.
[95] Exhibit B-3, BCUC IR 15.3, 15.5.
[96] PNG-West 2020-2021 RRA Proceeding, Exhibit B-2, Section 2.5.8, p. 43; Table 23.
[97] Exhibit B-6, BCUC IR 76.1.1.

years. Accordingly, PNG(NE) proposes to revisit the amortization period and start date as part of its 2022-2023 RRA.[98]

Under a scenario where PNG(NE) is approved to recover the full TSU Shared Corporate Services Costs in 2020 and 2021 without deferring any portion, the impact to the FSJ/DC and TR Divisions is as follows:[99]

- For the FSJ/DC Division, there would be an increase in residential customer rates of approximately 2.6 percent in 2020 with no material change in 2021. [100]
- For the TR Division, this would result in an in an increase in residential customer rates of approximately 1.4 percent with no material change in 2021.[101]

PNG(NE) also provides the following table to illustrate the estimated rate impact for its residential customers in the FSJ/DC Division assuming the deferral account is amortized over one, three and five years starting in 2021, assuming 2021 deliveries and 2021 customer rates remain constant for the future years.[102]

Table 3: Fort St John/Dawson Creek Division - Amortization and Estimated Rate Impact

		[---- Amortization						----]
Fort St John/Dawson Creek Division		**Year 2021**	**Year 2022**	**Year 2023**	**Year 2024**	**Year 2025**	**Year 2026**	**Year 2027**
One Year amortization period								
2020 addition to deferral account	377,000	377,000						
2021 addition to deferral account	373,000		373,000					
Total Amortization		377,000	373,000	-	-	-	-	-
Impact on Annual Revenue Requirement		377,000	(4,000)	(373,000)	-	-	-	-
Incremental Annual Impact on Residential Customer rates		1.72%	-0.02%	-1.51%	0.00%	0.00%	0.00%	0.00%
Three Year amortization period								
2020 addition to deferral account	377,000	125,667	125,667	125,667				
2021 addition to deferral account	373,000		124,333	124,333	124,333			
Total Amortization		125,667	250,000	250,000	124,333	-	-	-
Impact on Annual Revenue Requirement		125,667	124,333	-	(125,667)	(124,333)	-	-
Incremental Impact on Residential Customer rates		0.57%	0.51%	0.00%	-0.51%	-0.50%	0.00%	0.00%
Five Year amortization period								
2020 addition to deferral account	377,000	75,400	75,400	75,400	75,400	75,400		
2021 addition to deferral account	373,000		74,600	74,600	74,600	74,600	74,600	
Total Amortization		75,400	150,000	150,000	150,000	150,000	74,600	-
Impact on Annual Revenue Requirement		75,400	74,600	-	-	-	(75,400)	(74,600)
Incremental Impact on Residential Customer rates		0.34%	0.31%	0.00%	0.00%	0.00%	-0.31%	-0.30%

PNG(NE) provides a similar table for the TR Division.[103]

[98] Ibid., BCUC IR 76.1.
[99] Exhibit B-3, BCUC IR 15.6.
[100] Not including the impact of the rate smoothing mechanism (discussed in Section 3.3.1) for simplicity.
[101] Ibid.
[102] Exhibit B-3, BCUC IR 15.7.
[103] Ibid.

Table 4: Tumbler Ridge Division - Amortization and Estimated Rate Impact

Tumbler Ridge Division		Amortization Year 2021	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026	Year 2027
One Year amortization period								
2020 addition to deferral account	24,000	24,000						
2021 addition to deferral account	25,000		25,000					
Total Amortization		24,000	25,000	-	-	-	-	-
Impact on Annual Revenue Requirement		24,000	1,000	(25,000)	-	-	-	-
Incremental Annual Impact on Residential Customer rates		1.12%	0.05%	-1.11%	0.00%	0.00%	0.00%	0.00%
Three Year amortization period								
2020 addition to deferral account	24,000	8,000	8,000	8,000				
2021 addition to deferral account	25,000		8,333	8,333	8,333			
Total Amortization		8,000	16,333	16,333	8,333	-	-	-
Impact on Annual Revenue Requirement		8,000	8,333	-	(8,000)	(8,333)	-	-
Incremental Impact on Residential Customer rates		0.37%	0.38%	0.00%	-0.36%	-0.37%	0.00%	0.00%
Five Year amortization period								
2020 addition to deferral account	24,000	4,800	4,800	4,800	4,800	4,800		
2021 addition to deferral account	25,000		5,000	5,000	5,000	5,000	5,000	
Total Amortization		4,800	9,800	9,800	9,800	9,800	5,000	-
Impact on Annual Revenue Requirement		4,800	5,000	-	-	-	(4,800)	(5,000)
Incremental Impact on Residential Customer rates		0.22%	0.23%	0.00%	0.00%	0.00%	-0.22%	-0.22%

PNG(NE) proposes to seek approval for the amortization of this deferral account in future years, noting however it had incorrectly applied the short-term interest rate to the deferral account. PNG(NE) considers that applying the weighted average cost of debt rate would be more appropriate as it anticipates a longer amortization period. PNG(NE) proposes to amend its final regulatory schedules to reflect this change.[104]

Positions of the Parties

BCOAPO submits that should PNG(NE) be approved to recover the TSU Shared Corporate Services Costs that equal or approximate the amount sought, it would support the use of a deferral account to smooth the increase over a future period. BCOAPO also submits that the interest charged on the deferral account should not exceed the minimum interest required in order to avoid rate shock.[105]

Panel Determination

The Panel approves a new Shared Corporate Services Costs deferral account with a three-year amortization period and accruing interest at PNG(NE)'s Weighted Average Cost of Debt for each of the FSJ/DC and TR Divisions and PNG(NE) is directed to record in the deferral account a portion of the TSU Shared Corporate Services Costs allocation as follows:

- **FSJ/DC Division – $377,000 in 2020 and $374,000 in 2021 in the deferral account; and**
- **TR Division – $24,000 in 2020 and $25,000 in 2021 in the deferral account.**

Similar to PNG(NE) and BCOAPO, the Panel is concerned about the effect that the full recovery of TSU Shared Corporate Services Costs can have on customer rates. The Panel is also concerned about PNG(NE)'s proposal to defer a portion of the TSU Shared Corporate Services Costs for an unspecified length of time with no set amortization period.

[104] Exhibit B-6, BCUC IR 77.1.
[105] BCOAPO Final Argument, p. 14.

The Panel notes that the TSU Shared Corporate Services Costs are not one-time expenses but instead are recurring expenses that are likely to persist in future test periods. Accordingly, with no set amortization of the deferral account balance, the balance in the deferral account will likely continue to increase exponentially over the years, which will impact ratepayers in several ways. First, the balance in the deferral account attracts compounding interest, which will ultimately be paid by ratepayers. Second, as the deferral account balance grows, so to does the likelihood of a significant rate impact once the amortization of the deferral account commences. Lastly, deferring the costs over a longer timeframe will increase intergenerational inequity, as future ratepayers will pay a larger portion of costs incurred in the Test Period. In consideration of the limited load growth forecast for the PNG(NE) divisions, the Panel has concerns regarding PNG(NE)'s ability to increase load on the systems over the short and long term as a means to mitigate upward pressure on customer rates. Based on the foregoing, the Panel finds that it is unreasonable to defer a portion of the TSU Shared Corporate Services Costs indefinitely with no set plan for the recovery of these amounts.

The Panel has reviewed the rate impact of including the full allocation of the TSU Shared Corporate Services Costs for the FSJ/DC and TR Divisions over the Test Period and the impact if these amounts are deferred and amortized over a period of one, three and five years. The Panel recognizes that the full recovery in 2020 and 2021 would increase residential rates by approximately 2 percent in 2020 and agrees with PNG(NE) and BCOAPO that a deferral account mechanism would mitigate this rate impact. In the Panel's view, the amortization period for the amount deferred should balance the benefits of rate smoothing with upholding intergenerational equity. The Panel acknowledges that longer amortization periods will generally increase costs for ratepayers due to the accumulation of interest charges and the inflationary increases in the TSU Shared Corporate Services Costs. In reviewing the options of a one, three and five-year amortization period, the Panel finds that the three-year amortization period is appropriate, as this period realizes the benefits of smoothing rates while avoiding an inordinately long amortization period.

The Panel also recognizes BCOAPO's concern that the interest rate applied to the TSU Shared Corporate Services Costs deferral account should not exceed the minimum amount in order to avoid rate shock. In the PNG-West 2013 RRA Decision, the BCUC established key principles for the treatment of deferral accounts including the appropriate interest rate to be applied given the type of costs being deferred (capital or non-capital) and the amortization period. For deferral accounts for non-capital costs which are amortized beyond one year, the utility's Weighted Average Cost of Debt should be applied. In consideration of the Panel's approval of a three-year amortization period for the balance captured in the deferral account, the Panel finds the Weighted Average Cost of Debt to be the appropriate interest rate for the deferred portion of the TSU Shared Corporate Services Costs and is satisfied that this interest rate will not result in rate shock.

2.2 Reporting on Significant Capital Projects

In the PNG(NE) 2018-2019 Decision, the BCUC determined there was a need to develop a process to allow PNG(NE)'s future capital expenditures to be considered in advance of construction and assess when a certificate of public convenience and necessity (CPCN) application would be appropriate. By Order G-164-18A, the BCUC directed PNG(NE) to provide a proposal for a report 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) Capital Report) and include recommendations for:

- the form the annual report should take;
- the timing of the report;
- the regulatory review process;
- the level of detail to be required;
- description of capital projects to be included/excluded from the report; and
- any recommendations for minimum dollar thresholds.

This direction is in keeping with the same direction made to PNG-West by Order G-151-18. The proposed form and content of the PNG(NE) Capital Report is the same as that proposed by PNG-West in the 2020-2021 RRA proceeding.[106]

The proposed PNG(NE) Capital Report will include forecast and historic capital expenditures, where the reporting on forecast capital expenditures would be limited to planned non-recurring capital projects which would capture system extensions, new facilities and significant system modifications or additions as well as items that pertain to the maintenance and operation of existing assets or other non-discretionary items.[107] PNG(NE) proposes that this report be part of the Annual Report to the BCUC prepared for each of PNG's divisions and be filed by April 30 each year for review by the BCUC. PNG(NE) suggests an informal review process would be appropriate, ideally completed within 30 days of submission, such that the review process would not delay planned capital activities.[108]

Similar to PNG-West, PNG(NE) submits that there may be capital projects of urgent need in order to address unanticipated operational risks or customer in-service requirements, and as such, there may be projects that commence construction prior to the proposed PNG(NE) Capital Report being filed with the BCUC. To the extent that these projects meet the requirements for the filing of a CPCN, PNG(NE) submits that a CPCN would be filed as soon as reasonable cost estimates could be completed.[109]

Given that the proposed form and content of the PNG-West and PNG(NE) Capital Reports are the same, the Panel refers the reader to the PNG-West Decision for the discussion of the PNG-West Capital Report, as well as a more detailed description of the proposed content, timing of the report, and regulatory review process that will apply to both the PNG-West and PNG(NE) Capital Reports. However, given differences in the type, nature and level of capital expenditures between PNG-West and PNG(NE), we discuss the proposed reporting threshold for the PNG(NE) Capital Report and the CPCN threshold for PNG(NE) separately below.

Minimum Dollar Threshold for the PNG(NE) Capital Report

PNG(NE) proposes a minimum total capital project expenditure of $500,000 for project reporting purposes.[110] PNG(NE) determined that a $500,000 threshold was appropriate after completing a historic review of non-recurring capital expenditures and identified that most of the individual projects exceeded $500,000.[111]

[106] PNG-West Decision, Section 4.2, pp. 37-41.
[107] Exhibit B-2, Section 3.4.1.1, pp. 153-154.
[108] Ibid., pp. 153, 156.
[109] Exhibit B-3 BCUC IR 63.2.
[110] Exhibit B-2 (FSJ/DC), Section 3.4.1.1, p. 115; Exhibit B-2 (TR), Section 3.4.1.1, p. 92.
[111] Exhibit B-3, BCUC IR 62.2.

PNG(NE) submits a common reporting threshold for both PNG-West and PNG(NE) provides administrative efficiency and minimizes confusion over reporting requirements and/or confusion in the interpretation of reports submitted to the BCUC.[112] Additionally, PNG(NE) questions the added value in requiring PNG(NE) to report on projects of lesser amounts, considering that the reporting requirement arose from concerns as to whether a CPCN expenditure schedule would be in the public interest.[113] PNG(NE) notes it would be extremely inefficient from a regulatory perspective for either the BCUC or PNG(NE) to have to expend resources on the reporting and review of project or program amounts with a value of less than $500,000 when these types of projects or programs generally would not warrant an independent regulatory proceeding.[114]

PNG(NE)'s two-year RRAs will continue to identify individual projects that exceed a threshold of $50,000. Therefore, PNG(NE) proposes a higher threshold for the PNG(NE) Capital Report, to be filed annually. PNG(NE) submits a $500,000 threshold is reasonable as it strikes an appropriate balance of meeting the directive from the BCUC while not creating an onerous workload in order to prepare a report that will require additional resources and additional costs for compliance.[115]

Minimum Dollar Threshold for CPCN filings

PNG(NE) submits that it has historically made use of an informal threshold of $1,000,000 as a general guideline for determining the need for a CPCN filing.[116] However, based on a cursory review of other utilities under the BCUC's jurisdiction, PNG(NE) notes the threshold may be on the low side and recommends a higher CPCN threshold of between $1,500,000 to $2,000,000 be considered.[117] PNG(NE) submits that between 2015 to 2019, the proposed higher threshold would have required two CPCN applications during the five-year period (one for FSJ/DC and one for TR), the same required at the $1,000,000 threshold.[118]

Positions of the Parties

BCOAPO does not take a position on PNG(NE)'s proposal for reporting on significant capital projects or on the proposed minimum dollar threshold for filing future CPCN applications.

Panel Determination

The Panel acknowledges that PNG(NE) has satisfied the direction pursuant to Order G-164-18A and directs PNG(NE) to file a report on significant capital projects on or before April 30 annually as part of its Annual Report, that includes, but is not limited to, the following information:

- **All non-recurring capital projects with total costs of $500,000 or more, including the following details:**
    - **a description of the project;**
    - **type of project;**
    - **level of accuracy for the cost estimate (AACE[119] estimate class);**

[112] Ibid., BCUC IR 62.1.
[113] Ibid.
[114] Ibid.
[115] Ibid., BCUC IR 62.2.
[116] Ibid., BCUC IR 62.8, 62.8.2.
[117] Ibid., BCUC IR 62.8.2.
[118] Ibid., BCUC IR 62.8.2.
[119] Association for the Advancement of Cost Engineering.

- **actual and forecast costs to completion, broken down by year;**
- **estimated construction commencement date; and**
- **confirmation of intention to file a CPCN application or a UCA section 44.2 expenditure schedule, as appropriate.**

The Panel notes that consistency of these elements between PNG-West and PNG(NE) reduces regulatory burden and improves regulatory efficiency. However, the Panel has addressed the proposed reporting threshold and CPCN filing threshold in the context of PNG(NE) specifically, given its annual capital expenditures and total rate base are significantly less than those for PNG-West.

The Panel agrees with PNG(NE) that a common capital project reporting threshold amongst all PNG divisions provides regulatory efficiency, given that a lower threshold may result in additional regulatory burden for both PNG(NE) and the BCUC. In consideration of PNG(NE)'s past major projects, the Panel notes that there is likely limited value in establishing a threshold lower than that proposed. We also accept that PNG(NE) reports on non-recurring capital projects with a threshold of $50,000 as part of its RRA, which provides an additional opportunity for the BCUC to review capital projects of less than $500,000. Based on this, and consistent with the determination in the PNG-West Decision, the Panel finds PNG(NE)'s proposed minimum total capital project expenditure of $500,000 to be appropriate for the annual PNG(NE) Capital Report.

Where there are capital projects that are required to address unanticipated risks, customer requirements, or urgent needs, the Panel accepts that depending on timing, these projects may not be included in the PNG(NE) Capital Report prior to construction starting. However, the Panel considers it appropriate that PNG(NE) notify the BCUC of these projects in order to allow the BCUC to consider them in advance of construction. **Accordingly, for any non-recurring capital projects with total costs of $500,000 or more that are not included in the annual PNG(NE) Capital Report due to timing considerations, the Panel directs PNG(NE) to file the following details with the BCUC at least 30 days before construction commences:**

- **a description of the project;**
- **type of project;**
- **level of accuracy for the cost estimate (AACE estimate class);**
- **actual and forecast costs to completion, broken down by year;**
- **estimated construction commencement date; and**
- **confirmation of intention to file a CPCN application or a UCA section 44.2 expenditure schedule, as appropriate.**

The Panel agrees with PNG(NE) that the current $1,000,000 informal CPCN threshold may be too low to be considered reasonable. The Panel acknowledges that this threshold may not offer the most efficient regulatory review of PNG(NE)'s capital projects, considering this may include projects that are not only lower in cost, but also have limited complexity and negligible impact. Further, the Panel notes the number of CPCNs from 2015-2019 is unchanged when higher thresholds proposed by PNG(NE) are applied and there are regulatory and administrative efficiencies by having common thresholds between PNG-West and PNG(NE).

While regulatory certainty is desirable, the Panel is reluctant to establish a formal threshold for CPCN applications as there may be instances where a project entailing a lower dollar value may nonetheless have a unique public interest component which warrants review. In such cases, the BCUC must have the flexibility to examine the need, rationale and costs of such projects. Accordingly, and while not directing PNG(NE) to do so, the Panel considers that PNG(NE)'s proposed CPCN filing threshold of $1,500,000 or above for capital projects that require a CPCN to be reasonable as the BCUC would have an interest in reviewing projects of this magnitude on a prospective basis. The Panel encourages PNG(NE) to consider this same threshold for the section 44.2 UCA expenditure schedule filings. Further, regardless of any formal CPCN filing threshold level, it does not preclude the BCUC from exercising its jurisdiction under section 45(5) of the UCA to require a CPCN for extensions, irrespective of the forecast cost, if it considers this to be warranted. The Panel further notes that the BCUC can review the balance of capital projects in an RRA or subsequently in a prudency review.

2.3 Impact of COVID-19 Pandemic

During the IR process, PNG(NE) was asked to address the impact of COVID-19 on the 2020-2021 test year forecast revenue requirements. In response, PNG(NE) states it does not anticipate COVID-19 having a material impact on the timing of any IT projects, capital projects or new staff position start dates, nor is it expecting any material impact to the spend on capital programs.[120] PNG(NE) notes it does not yet have evidence of any substantial adverse impact on gas consumption as a result of COVID-19;[121] however, the impacts to demand may change throughout and following the pandemic as customers adjust their day to-day habits and business requirements.[122] Additionally, PNG(NE) asserts that the forecasts as presented for the Test Period contain the most reasonable and reliable forecasts and does not believe that any significant revision to those forecasts is warranted.[123]

PNG(NE) also notes that it had filed a separate application with the BCUC for approval of the creation of a COVID-19 deferral account to capture unrecovered revenues and unplanned costs and cost savings arising from the COVID-19 pandemic. The BCUC approved that application by Order G-147-20 issued June 10, 2020.[124]

Positions of the Parties

In BCOAPO's Final Argument, it provides its expectation that COVID-19 will impact PNG(NE)'s forecast deliveries and revenues, including increased residential demand, primarily due to sheltering and self-isolation requirements, and to decreased commercial and industrial demand due to curtailment of activities.[125]

BCOAPO submits that "as a regulated utility, PNG enjoys volatility protection in the form of established deferral accounts transferring forecast risk from the shareholder to ratepayers" as well as the ability to come before the "BCUC to seek a financial remedy in the event of exogenous factors that threaten its financial stability or solvency." BCOAPO also highlights that PNG(NE) received approval of the COVID-19 deferral account which BCOAPO submits protects PNG(NE) from incremental costs and bad debt costs arising due to COVID-19.[126]

[120] Exhibit B-6, BCUC IR 65.1.1.
[121] Exhibit B-7, BCOAPO IR 1.1.
[122] Exhibit B-6, BCUC IR 65.1.
[123] Exhibit B-5, BCOAPO IR 1.1; Exhibit B-7, BCOAPO IR 13.1.
[124] Ibid., BCOAPO IR 1.2.
[125] BCOAPO Final Argument, p. 2.
[126] Ibid., p. 5.

Additionally, BCOAPO addresses the appropriateness of the current risk premium embedded in PNG(NE) rates and questions whether the COVID-19 deferral account offers further protection to the utility based on interest earned as compared to that pre COVID-19 pandemic.[127]

PNG(NE) notes that, as of the date of its Reply Argument, there is no evidence indicating a decrease in actual deliveries against forecast, but rather total actual deliveries are generally in line with forecast deliveries.[128] PNG(NE) also highlights that there are deferral accounts in place to capture several demand variances, including residential and commercial use per account and load variances for some industrial customers, thereby providing ratepayers protection from the impacts of such variances. Further, PNG(NE) submits that the protections provided by the established deferral mechanisms in place, including the COVID-19 deferral account, are not one-way and favourable solely to the benefit of the shareholder but rather, protection is provided to both the shareholder and ratepayers. This includes the COVID-19 deferral account, which captures both incremental costs and savings arising from the pandemic.[129]

With respect to the concerns BCOAPO raises regarding the current risk premium, PNG(NE) notes that it has provided an update to its business risk assessment in the Application and is not proposing any changes to its cost of capital components at this time.

Panel Discussion

The Panel has reviewed the evidence to support PNG(NE)'s Test Period revenue requirements and agrees with PNG(NE) that there is no evidence to support changes to the forecasts as a result of the COVID-19 pandemic at this time. Further, the Panel agrees with PNG(NE) that the established forecast variance deferral accounts, including the COVID-19 deferral account which records unrecovered revenues and unplanned costs and savings arising from the COVID-19 pandemic, are not biased towards either the shareholder or ratepayer. These deferral accounts capture variances between forecast and actual costs and/or revenues and may result in either a refund to or recovery from ratepayers.

The Panel notes BCOAPO's concerns raised with respect to PNG(NE)'s current risk premium and recognizes that as directed by Order G-47-14, PNG(NE) includes an updated business risk assessment as part of its RRAs. This allows the Panel to determine if there have been any significant changes to the circumstances faced by the utility with respect to the level of business risk which would warrant review. The Panel is not persuaded that there is sufficient evidence to suggest a change to PNG(NE)'s current risk premium is warranted at this time.

2.4 PNG-West and PNG(NE) Rate Design

After reviewing the evidence in this proceeding, in conjunction with that in the PNG-West Proceeding, the Panel has observed the following in the current Test Period as compared to the previous test period:

[127] BCOAPO Final Argument, p. 5.
[128] PNG(NE) Reply Argument, Section 2.1.1, pp. 1-2, para 7.
[129] Ibid., Section 2.1.2, pp. 2-3, paras 9-11.

- PNG-West and PNG(NE) are forecasting an increase in operations and maintenance (O&M) costs[130] and capital expenditures[131];
- The PNG-West system continues to experience unutilized capacity, which has persisted since the loss of its largest industrial customers, specifically Methanex Corporation in 2005 and West Fraser Mills Ltd. In 2010.[132] In addition, minimal load growth is expected;[133]
- The PNG(NE) FSJ/DC Division has experienced a decrease in overall throughput over the period of 2013-2016 with a declining trend residential use per account.[134] In the current Test Period, the PNG(NE) FSJ/DC Division is forecasting low or near zero load growth;[135] and
- The PNG(NE) TR Division faces a significant level of volatility, both in terms of customer count and overall throughput.[136] And apart from a forecast increase in load for the TR's Division only industrial customer, PNG(NE) is otherwise forecasting little or no growth over the Test Period for the region.[137]

These factors are concerning to the Panel, particularly given the BCUC's observations in the PNG(NE) 2018-2019 RRA Decision:[138]

> With reference to the current Application, PNG(NE) has explained that when the proposed decrease to both the RSAM rate riders and commodity costs are taken into account, the net impact in terms of 2018 and 2019 rates is much more moderate than what is suggested by consideration of the revenue requirements alone. However, while the current circumstances have served to moderate the impacts of increased revenue requirements…, it is not reasonable to assume that this reprieve will continue into the future. Given its size, its less stable regional economy and the infrastructure required to sustain service, the community of TR is and will continue to be, more susceptible to greater rate volatility than other PNG divisions. The question is how this is best managed going forward.
>
> The Panel notes that we will likely continue to be in a period of generally stable natural gas pricing. If this were to change and there were a significant increase in the cost of gas, it would have a severe impact on TR customer rates. This could result in some of the TR existing customer base switching to alternative fuels leading to an even bigger impact on delivery rates for those where fuel switching is not a viable option. There is some evidence to suggest that this may already be occurring as Table 2 indicates that the TR natural gas use per customer has dropped significantly since 2013.

Given these concerns, the BCUC urged PNG(NE) at that time to consider options to the current rate design including postage stamp rates for its service area:[139]

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130 Exhibit B-2 (FSJ/DC), Section 2, pp. 17-18, Table 7 & 8; Exhibit B-2 (TR), Section 2, pp. 17-18, Table 5 & 6; PNG-West 2020-2021 RRA Proceeding Exhibit B-2, Section 2, pp. 17-18, Table 5 & 6.

131 Exhibit B-2 (FSJ/DC) Section 2.13.1.1.1, p. 64, Table 31; Section 2.13.1.1.2, p. 72, Table 32; Section 3.2, p. 94, Table 38; Exhibit B-2 (TR) Section 2.13.1.1.1, p. 61, Table 28; Section 2.13.1.1.2, p. 63, Table 29; Section 3.2, p. 77, Table 36; PNG-West 2020-2021 RRA Proceeding Exhibit B-2, Section 2.13.1.1.1, p. 95, Table 38; Section 2.13.1.1.2, p. 104, Table 39; Section 3.2, p. 130, Table 45.
PNG(NE) FSJ/DC and PNG(NE) TR: capital expenditures in test years 2020 and 2021 are greater than PNG-West 2018-2019 Decision, however capital expenditures in test year 2021 is less than test year 2020.

132 PNG and PNG(NE), Generic Cost of Capital Proceeding – Stage 2, Exhibit B-14, pp. 15-16.

133 PNG-West 2020-2021 RRA Proceeding Exhibit B-2, Section 2.1, p. 23, Table 9; Exhibit B-2, Appendix C, p. 5.

134 Exhibit B-2 (FSJ/DC), Appendix B, p. 5.

135 Exhibit B-3, BCUC IR 15.3.

136 Exhibit B-2 (TR), Appendix B, p. 5.

137 Exhibit B-3, BCUC IR 15.3.

138 PNG(NE) 2018 RECAP-2019 RRA Decision, p. 28.

139 Ibid., p. 29.

> The Panel encourages PNG(NE) to consider options to the current rate design and notes that harmonization of rates among its various divisions would be in keeping with historic government support for postage stamp rates. Consideration of alternative rate designs such as postage stamp rates would also offer some potential advantages. For one it could help create greater stability of rates within the PNG(NE) divisions and potentially forestall any fuel switching which may be currently occurring within TR resulting in better usage of existing assets and reduce the risk of stranded assets. Also, depending upon the approach taken, there would be potential for regulatory savings related to reduced preparation and adjudication of multiple RRAs. As a consequence, regulatory costs could be reduced and the time saved allocated to other activities which is a benefit to all PNG(NE)ratepayers.

The evidence in this proceeding has raised similar concerns for the Panel. The Panel is concerned that despite the BCUC's encouragement in the PNG(NE) 2018-2019 Decision, there still does not appear to be any specific plan to address these ongoing challenges.

The Panel considers it may be in the best interests of both the shareholder and ratepayers for PNG to examine the long-term plans of its utilities and the continued viability of their current rate design as part of the utilities' next RRAs. The Panel urges PNG to focus on the consideration and development of a comprehensive business strategy to address the current challenges, which may necessitate consideration of rate design changes including postage stamp rates and/or amalgamation of its various entities to reduce costs on a consolidated basis or produce greater operational efficiencies for the mutual benefit of ratepayers and the shareholder.

3.0 Cost of Service

3.1 Operating, Maintenance, Administrative and General Expenses

PNG(NE) is requesting recovery of the following operating, maintenance and administrative and general (OMA) expenses for 2020 and 2021 as outlined in Table 5 and Table 6 below:[140]

Table 5: FSJ/DC Operating, Maintenance, and Administrative and General Expenses

Fort St. John/ Dawson Creek (FSJ/DC)	Test Year 2020	Test Year 2021
Operating (before transfers to capital)	$6,368,000	$6,493,000
Maintenance	$508,000	$519,000
Administrative and General (before transfers to capital)	$3,318,000	$3,228,000
Less: transfers to capital - operating	$(288,000)	$(268,000)
Less: transfers to capital – admin. & gen.	$(332,000)	$(288,000)
Total	**$9,574,000**	**$9,684,000**

[140] Exhibit B-2, FSJ/DC, pp. 29, 36, 38; Exhibit B-2, TR, pp. 28, 34, 36 (Tables created by BCUC staff).

Table 6: TR Operating, Maintenance, and Administrative and General Expenses

Tumbler Ridge (TR)	Test Year 2020	Test Year 2021
Operating (before transfers to capital)	$821,000	$858,000
Maintenance	$128,000	$131,000
Administrative and General (before transfers to capital)	$293,000	$295,000
Less: transfers to capital - operating	$(30,000)	$(26,000)
Less: transfers to capital – admin. & gen.	$(30,000)	$(21,000)
Total	**$1,182,000**	**$1,237,000**

The forecast OMA expenses presented in the above tables are subject to adjustments and corrections identified by PNG(NE) during the regulatory process and summarized in Appendix A to this decision and the directives and determinations in this decision.

The 2020 adjusted[141] forecast OMA expenses are $900,000 and $157,000 higher than the 2019 forecast OMA expenses for the FSJ/DC and TR Divisions, respectively. PNG(NE) submits that the primary drivers for these increases include:[142]

i. Planned activities to ensure compliance with pipeline integrity related codes, standards and regulations and address aging infrastructure concerns for the FSJ/DC and TR Divisions;

ii. Two additional full-time equivalent positions in field operations in the FSJ/DC Division;[143]

iii. Increased plant maintenance and plant turnaround activities in the TR Division; and

iv. Increased administrative and general costs mainly due to an allocation of costs from PNG-West to replace the accounting and human resources information systems for the FSJ/DC and TR Divisions (as discussed earlier in Section 2.1.2 of this decision) and higher pension expense for the TR Division.

Further, the increase in the adjusted forecast OMA expenses for the TR Division is partially offset by higher transfers to capital of $31,000 due to increased capital programs in 2020.[144]

The forecast 2021 OMA expenses are comparable to the 2020 forecast, with an increase of $110,000 in the FSJ/DC Division and an increase of $41,000 in the TR Division. The increase in the TR Division is mainly attributable to increasing number of meter recalls required as well as inflationary increases and lower transfers to capital due to less capital projects in 2021. Similar to the TR Division, there were also lower overheads capitalized in the FSJ/DC Division due to fewer capital projects in 2021.[145]

[141] The adjusted forecast includes adjustments and corrections identified during the regulatory process as summarized in section 6 of PNG(NE)'s Final Argument and Appendix A to this decision.
[142] PNG(NE) Final Argument, pp. 8, 10.
[143] Ibid., pp. 8, 17; Exhibit, B-3, BCUC IR 7.2.
[144] Ibid., p. 11.
[145] Ibid., pp. 9, 11.

Positions of the Parties

Apart from accepting the pipeline integrity-related costs as filed for both the FSJ/DC and TR Divisions[146] as mentioned above in Section 2.1.1, BCOAPO takes no position on PNG(NE)'s proposal for forecast OMA expenses.

Panel Determination

The Panel accepts the 2020 and 2021 OMA expenses as reasonable, subject to the adjustments identified by PNG(NE) during the regulatory process and summarized in Appendix A to this decision and the directives and determinations in this decision. The Panel has reviewed the evidence and argument on record in the proceeding and PNG(NE)'s reasons for the increase in OMA expenses in the Test Period and finds the OMA expenses requested for recovery in 2020 and 2021 to be reasonable.

3.2 Rate Base

PNG(NE) forecasts capital expenditures before overhead for the FSJ/DC Division of $9.187 million in 2020 and $5.899 million in 2021.[147] In comparison, the average of actual annual capital expenditures incurred for FSJ/DC over the past five years is $5.093 million.[148] As part of its TR Division Application, PNG(NE) forecasts capital expenditures before overhead to be $0.896 million in 2020 and $0.400 million in 2021.[149] In comparison, the average of actual annual capital expenditures incurred for TR over the past five years is $0.552 million.[150]

Included in the PNG(NE) forecast capital expenditures are costs for the Automated Meter Reading (AMR) installation project.[151] We review this project and the associated expenditures in Section 3.2.1 below.

Positions of the Parties

BCOAPO notes a significant variance between PNG(NE)'s approved forecast and actual distribution main expenditures over the period 2015-2019.[152] Over this period, PNG(NE)'s total approved distribution main expenditure was $2.391 million and the actual distribution main expenditure was $1.263 million.[153] BCOAPO raises the concern that ratepayers pay for the return on equity and debt, taxes and depreciation on forecast capital additions during the Test Period, even if the actual capital additions do not materialize.[154] However, BCOAPO acknowledges that PNG(NE)'s actual total capital spending over the same period slightly exceeded approved amounts. Therefore, the excess costs to ratepayers due to the identified variance did not occur.[155] Nonetheless, BCOAPO submits that PNG(NE) should consider the appropriateness of its distribution mains forecasting methodology. Apart from this, BCOAPO does not take a position on PNG(NE)'s capital expenditures.

In response to the concerns raised by BCOAPO, PNG(NE) notes that there can be challenges to forecasting distribution mains projects given the close connection and high correlation between local economic activity and

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146 BCOAPO Final Argument, pp. 7–8.
147 Exhibit B-2 (FSJ/DC), Section 2.13.1.1, p. 63.
148 PNG(NE) Final Argument, para. 95.
149 Exhibit B-2 (TR), Section 2.13.1.1, p. 60.
150 PNG(NE) Final Argument, para. 95.
151 Exhibit B-2 (FSJ/DC), Section 2.13.1.1, p. 67; Exhibit B-2 (TR), Section 2.13.1.1, p. 61.
152 BCOAPO Final Argument, p. 8.
153 Exhibit B-7, BCOAPO IR 12.1.
154 BCOAPO Final Argument, p. 8.
155 Ibid.

oil and gas prices and activity in the Peace River region.[156] PNG(NE) further submits an acknowledgment of the magnitude of the variance identified by BCOAPO and commits to reviewing and revising its forecasting methodology in advance of the next RRA. In response to IR's regarding forecasting of other capital expenditures, such as New Services, PNG(NE) states that the use of a historical five-year average expenditure is considered appropriate, as it allows PNG(NE) to smooth out the impacts of any economic shift that is experienced by regional markets. PNG(NE) further submits that using other methodologies, such as forecast predictions into the future based upon outdated market research, or utilization of the previous year or even an average of previous two years, may prove problematic and unreliable in such a volatile resource-based market.[157]

In response to IRs, PNG(NE) identified a budgetary oversight which resulted in the 2020 and 2021 distribution mains forecast to be incorrectly overstated.[158] PNG(NE) further submits that it has corrected this oversight by reducing its distribution main forecast for the test years and allocating the remainder of the original forecast to the steel main replacement project.

Panel Determination

The Panel is satisfied that PNG(NE) has demonstrated a need for the capital expenditures submitted in this Application and accepts them as filed in the Application, subject to any adjustments identified by PNG(NE) during the regulatory process and summarized in Appendix A to this decision and the directives and determinations in this decision.

However, the Panel shares BCOAPO's concern regarding the forecasting of some capital expenditures. During PNG(NE)'s stated upcoming review of forecasting methodologies, the Panel urges PNG(NE) to determine the suitability of continuing to rely on historic five-year expenditure averages for forecasting, in comparison to other methodologies, in light of the current "downturn in development in northeastern British Columbia."[159]

3.2.1 Automated Meter Reading

On March 25, 2020, PNG(NE) filed a CPCN application with the BCUC to update and replace the current manual meter reading process for residential and commercial customers with AMR infrastructure for the FSJ/ DC and TR Divisions.[160] By Order C-3-20 dated September 24, 2020, the BCUC granted the CPCN for the AMR project, with the reasons for decision to follow.

The current 2020-2021 RRA includes the Test Period impact of both the capital additions of the AMR project and the associated operating costs and savings, as PNG(NE) anticipated approval of the CPCN at the time of filing the Application.[161]

PNG(NE) notes that the AMR project has an estimated capital cost of $3.862 million in 2020 and severance costs for the elimination of five meter-reader positions of $29,700 and $2,300 in 2020 for the FSJ/DC and TR Divisions, respectively. However, once the AMR project is implemented, PNG(NE) expects it will offer significant operating cost savings of $558,500 and $18,500 per year commencing in 2021 for the FSJ/DC and TR Divisions,

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156 PNG(NE) Final Argument, para. 23.
157 Exhibit B-3, BCUC IR 27.2.
158 Ibid., BCUC IR 30.1.
159 Exhibit B-2, Section 3.1.2, p. 94.
160 PNG(NE) Final Argument, pp. 18; Exhibit B-2, p. 30.
161 Exhibit B-6, BCUC IR 81.1.

respectively, for labour, benefit and equipment costs associated with a workforce reduction of five meter reader positions.[162]

The tables below outline the rate impact associated with the expected change in cost of service resulting from the AMR capital and operating cost(s)/savings for 2020 and 2021. Specifically, Table 7 shows the rate impact for the FSJ/DC Division and Table 8 shows the impact for the TR Division:[163]

Table 7 : FSJ/DC Rate Impact

Fort St. John/ Dawson Creek (FSJ/DC) Rate increase/(decrease)	Test Year 2020	Test Year 2021
Operating cost(s)/savings	0.20%	(3.5)%
Capital Costs	0.15%	3.0%
Total	**0.35%**	**(0.5)%**

Table 8: TR Rate Impact

Tumbler Ridge (TR) Rate increase/(decrease)	Test Year 2020	Test Year 2021
Operating cost(s)/savings	0.13%	(1.0)%
Capital Costs	0.07%	1.7%
Total	**0.2%**	**0.7%**

The impact on the Test Period revenue requirements discussed above assumed that the CPCN would be granted by the second quarter of 2020. During the current RRA and prior to receiving CPCN approval for the project, PNG(NE) noted that if the CPCN is granted after July 31, 2020 but before the fourth quarter of 2020, it would result in a delay in the implementation of the project to the second quarter of 2021 rather than the end of 2020, and the realization of a half-year of operational savings in test year 2021 instead of a full-year of savings. Further, if the AMR project is not implemented and operational before the end of 2020, the severance costs may be pushed into 2021.[164]

Positions of the Parties

BCOAPO takes no position on PNG(NE)'s proposal for the AMR project.

Panel Determination

PNG(NE) is directed to update its final regulatory schedules to reflect the new anticipated timing of the AMR project and the impact on Test Period forecast capital and operating cost(s)/savings, for both the FSJ/DC and TR Divisions. Subject to these updates, the Panel accepts the Test Period AMR project costs.

[162] PNG(NE) Final Argument, pp. 18, 32; Exhibit B-3, BCUC IRs 8.1 and 32.1.
[163] Exhibit B-3, BCUC IR 8.1.2, 32.3.1 and 32.3.2 (Tables created by BCUC and percentages adjusted slightly for rounding differences, where applicable).
[164] PNG(NE) Final Argument, pp. 18–19; Exhibit B-3, BCUC IR 8.2; Exhibit B-6, BCUC IR 81.1 and 81.1.1.

In the next RRA, the Panel directs PNG(NE) to provide a breakdown of the Test Period costs and cost reductions related to the AMR project, by year and by account, for each of the FSJ/DC and TR Divisions.

As noted above, the timing of the BCUC decision regarding the AMR CPCN application impacts the timing of the AMR project implementation and the associated capital expenditures and operational costs and savings. Given that the BCUC issued its decision approving the AMR CPCN application on September 24, 2020, the Panel understands that the AMR infrastructure is now expected to be installed during the second quarter of 2021 rather than the end of 2020. Consequently, operational cost savings will only be realized for the second half of 2021, at the earliest, and severance costs may be incurred in 2021.

3.3 Deferral Accounts

3.3.1 Proposed Rate Deferral Mechanism

PNG(NE) seeks approval to create a short-term interest bearing deferral account in 2020 to smooth the impact of the combined net revenue deficiencies for 2020 and 2021 to be fully amortized in 2021, which is consistent with the approach to smooth rates in the PNG(NE) 2018-2019 RRA.

For the FSJ/DC Division, PNG(NE) proposes to move $0.330 million of the 2020 revenue deficiency to a short-term interest bearing deferral account for amortization in 2021. This results in residential delivery rate increases of approximately 11 percent in each of 2020 and 2021. In the absence of the rate deferral mechanism, the residential delivery rates changes would be approximately 14 percent in 2020 and 7 percent in 2021.[165] For the TR Division, PNG(NE) proposes to move $53,000 of the 2021 revenue deficiency to a short-term interest bearing deferral account and amortize in 2020. This results in residential delivery rate increases of approximately 3 percent in each of 2020 and 2021.

Based on the corrections/adjustments identified during the regulatory process and summarized in Appendix A to this decision, the amounts shifted between the years will be different from that proposed in the Application in order to allow rate increases to be applied evenly over the Test Period. This results in residential delivery rate increases of approximately 9 to 10 percent for FSJ/DC and 1.5 percent for TR in each of 2020 and 2021.[166]

Panel Determination

The Panel approves the establishment of a rate smoothing deferral account for each of the FSJ/DC and TR Divisions bearing interest at PNG(NE)'s short-term interest rate to record the following amounts:

- **FSJ/DC Division: $0.330 million of the 2020 revenue deficiency, to be amortized in 2021.**
- **TR Division: $53,000 of the 2021 revenue deficiency, to be amortized in 2020.**

The Panel finds that PNG(NE)'s approach is reasonable, given that it results in the benefit of rate stability over the Test Period, with rate increases smoothed evenly over the two years. This approach is consistent with that approved in the PNG(NE) 2018-2019 RRA.

[165] Exhibit B-2, FSJ/DC, p. 5 and TR, p. 7.
[166] PNG(NE) Final Argument, p. 12.

3.3.2 Accelerated CCA Deferral Account

As part of the Government of Canada's 2018 Fall Economic Statement tabled on November 21, 2018, a new Accelerated Investment Incentive was enacted to allow Canadian businesses to accelerate CCA deductions for assets purchased after November 20, 2018. The Accelerated Investment Incentive allows certain capital property that is subject to the general CCA rules to be eligible for an enhanced first-year allowance equal to three times the normal first-year tax depreciation deduction that would otherwise apply in the year the asset is available for use. This large deduction in the first year would ultimately result in lower tax deductions in future years. PNG(NE) has utilized the accelerated CCA provision for 2019 and has recorded its impact, in a short-term interest deferral account. The calculated provision for the FSJ/DC and TR Divisions is $127,000 and $8,000, respectively. PNG(NE) requests approval for the proposed Accelerated CCA deferral account for the FSJ/DC and TR Divisions, as well as to fully amortize the balance in test year 2020 and to subsequently eliminate the account once the balance is fully amortized.[167]

Panel Determination

The Panel accepts that this is a reasonable request that benefits ratepayers by mitigating cost of service increases in 2020. **The Panel approves PNG(NE)'s proposal to establish an Accelerated CCA deferral account for each of the FSJ/DC and TR Divisions, bearing interest at PNG(NE)'s short-term interest rate, to record the 2019 Accelerated CCA provision of $127,000 and $8,000 for the FSJ/DC and TR Divisions, respectively. PNG(NE) is also approved to fully amortize the balance in test year 2020 and to subsequently eliminate the deferral accounts.**

3.3.3 Studies Deferral Account

The Studies deferral account was established to accumulate costs related to a sweet gas supply option study for the TR Division. Pursuant to Order G-132-16 of the PNG(NE) 2016-2017 RRA Reasons for Decision, the BCUC approved PNG(NE)'s request to amortize costs in this deferral account over a three-year period commencing on January 1, 2016. As this account was fully amortized in 2018, and there is no further need for the account, PNG(NE) is requesting the dissolution of this deferral account.[168]

Panel Determination

The Panel acknowledges the Studies deferral account has fulfilled its purpose and has a $nil balance at the end of fiscal 2018. **Accordingly, the Panel approves PNG(NE)'s request to close the Studies deferral account.**

4.0 Proposed Delivery Rates

PNG(NE) seeks BCUC approval to increase its delivery rates for the FSJ/DC Division to recover the projected revenue deficiency of $1.414 million in 2020 and $1.483 million in 2021, and to increase its TR delivery rates to recover the projected revenue deficiency of $24,000 in 2020 and $25,000 in 2021.[169] This includes the provision for the adjustments identified by PNG(NE) during the regulatory process and summarized in Appendix A to this

[167] Exhibit B-2 (FSJ/DC), Section 2.10, pp. 59-60; Exhibit B-2 (TR), Section 2.10 p. 57.
[168] Exhibit B-2 (TR), Section 2.10 p. 57; PNG(NE) Final Written Argument, Section 14.1, p. 25.
[169] Exhibit B-8, Evidentiary Update BCUC IR 1.4.

decision. PNG(NE) has allocated the test year revenue deficiencies to customers based on forecast margin recovery by customer class, a methodology that has been previously accepted by the BCUC.[170] Similar to the PNG(NE) 2018-2019 RRA, PNG(NE) proposes that the full impact of the combined rate changes anticipated for test years 2020 and 2021 be smoothed over the two-year period through the use of a short-term interest bearing deferral account to be fully amortized in 2021.[171] This proposed rate deferral mechanism as described in Section 3.3.1.

The residential delivery rate increases resulting from the projected revenue deficiencies for 2020 and 2021 are as follows: [172]

- FSJ Division: approximately 9.8 percent in 2020 and 9.3 percent in 2021.
- DC Division: approximately 10.2 percent in 2020 and 9.7 percent in 2021.
- TR Division: approximately 1.4 percent in 2020 and 1.5 percent in 2021.

By Order G-168-12, the BCUC approved a Revenue Stabilization Adjustment Mechanism (RSAM) rate rider deferral account to capture variances between forecast and actual sales volumes, pertaining to residential and small commercial customers. PNG(NE) also requests approval to adjust the RSAM rate rider for the Test Period in the following manner:

- FSJ and DC Division: a reduction in the RSAM rate rider from $0.059/GJ in 2019 to a credit of $0.022/GJ in 2020; and a subsequent increase to a credit of $0.012/GJ in 2021.[173] The changes in the forecast RSAM rate riders reflect the net credit additions to the RSAM pool in 2018 and 2019 as a result of colder than normal weather experienced during the past two years, the forecast lower use per account, as well as the recovery of the historical RSAM balances through the current rider.[174]
- TR Division: a reduction in the RSAM rate rider from $0.049/GJ in 2019 to a credit of $0.923/GJ in 2020; and a subsequent increase to a credit of $0.406/GJ in 2021. [175] The change in the forecast RSAM rate riders reflects the credit additions to the RSAM pool in 2018 and 2019 as a result of colder than normal weather experienced in 2018 and 2019.[176]

The RSAM rate riders are calculated based on a two-year amortization period. The BCUC previously approved the two-year amortization period in order to ensure compliance with the requirements of US GAAP.[177]

PNG(NE) submits that the evidence it filed during the course of this proceeding allow the BCUC to find that the cost of service applied for by PNG(NE) for both test years 2020 and 2021 are just and reasonable having regard to provisions of sections 59 and 60 of the UCA.[178]

Panel Determination

The Panel approves PNG(NE)'s request for recovery of the 2020 and 2021 revenue requirement and resultant delivery rate changes on a permanent basis, subject to the adjustments identified by PNG(NE) during the

[170] Exhibit B-2 (FSJ/DC), Section 2.15.1, p. 84; Exhibit B-2 (TR), Section 2.15.1, p. 70.
[171] Ibid., Section 1.3, p. 6; Exhibit B-2 (TR), Section 1.3, p. 7.
[172] Exhibit B-8, Evidentiary Update BCUC IR 1.4.
[173] Exhibit B-2 (FSJ/DC), Tab 6, pp. 19 and 39.
[174]Ibid., Section 2.15.1, p. 85.
[175] Exhibit B-2 (TR), Tab 6, pp. 10 and 21.
[176]Ibid., Section 2.15.1, p. 70.
[177] Exhibit B-2 (FSJ/DC), Section 2.15.3, p. 85; Exhibit B-2 (TR), Section 2.15.3, p. 70; Order G-131-13 with accompanying Decision, Decision, Section 6.4, p. 35.
[178] PNG (NE) Final Argument, Section 19, p. 42.

regulatory process and summarized in Appendix A to this decision and the directives and determinations in this decision. The 2020 and 2021 RSAM riders set forth in the Application are approved on a permanent basis.

The Panel notes the Test Period delivery rate increases for the FSJ/DC Division are nearly 10 percent. Accordingly, this raises a concern regarding possible rate shock for PNG(NE)'s customers. However, the Panel notes that the forecast bill impact for residential and small commercial customers of all PNG(NE) divisions is less than 10 percent over the Test Period,[179] which helps mitigate the Panel's concerns regarding potential rate shock. The Panel notes that the 10 percent threshold, if it is exceeded, is only a guideline and does not in and of itself compel an adjustment to the applied for revenue deficiency and accepts that the rate deferral mechanism helps to mitigate rate volatility. Even if the delivery rate changes were to be considered as rate shock, there is no evidence presented to suggest that the underlying pressures on rates can be mitigated by alternative means.

Notwithstanding the above, the Panel recognizes that the low cost of natural gas is a key contributing factor to abating the incremental bill increase. Accordingly, any future increase in gas prices would negatively impact customer rates overall. The UCA provides the BCUC with the jurisdiction to set rates that encourage utilities to increase efficiency, reduce costs and enhance performance.[180] It is incumbent on PNG(NE) to explore cost effective solutions that, where possible, ultimately limit increases in costs to the ratepayers. This includes the proposed pipeline system integrity management programs and IT projects, which may require PNG(NE) to consider cost-effective alternatives to address these needs. In such cases, PNG(NE) should thoroughly assess those options to seek out any efficiencies or savings over the short and/or long term.

DATED at the City of Vancouver, in the Province of British Columbia, this 21st day of October 2020.

Original signed by:

A. K. Fung, QC
Panel Chair / Commissioner

Original signed by:

C. Brewer
Commissioner

Original signed by:

M. Kresivo, QC
Commissioner

[179] Exhibit B-8, Evidentiary Update IR 1.4.1.
[180] UCA, section 60(1)(b)(iii).

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ORDER NUMBER
G-263-20

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

and

Pacific Northern Gas (N.E.) Ltd.
2020-2021 Revenue Requirements Application
for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions

BEFORE:
A. K. Fung, QC, Panel Chair
C. Brewer, Commissioner
M. Kresivo, QC, Commissioner

on October 21, 2020

ORDER

WHEREAS:

A. On November 29, 2019, Pacific Northern Gas (N.E.) Ltd. [PNG(NE)] filed its 2020-2021 Revenue Requirements Application (RRA) with the British Columbia Utilities Commission (BCUC) for the Fort St. John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) Divisions pursuant to sections 58 to 61, 89 and 90 of the *Utilities Commission Act* (UCA) (Original Application);

B. By Order G-331-19 the BCUC approved PNG(NE)'s delivery rates and Rate Stabilization Adjustment Mechanism (RSAM) on an interim and refundable/recoverable basis effective January 1, 2020, and established a regulatory timetable for the review of the Original Application which included dates for intervener registration, filing an amended application, BCUC and intervener information request (IR) No. 1 and 2, and PNG(NE) responses to IRs;

C. British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and Tenants Resource and Advisory Centre (BCOAPO et al.) participated as an intervener in the proceeding;

D. On February 28, 2020, PNG(NE) filed its amended application for approval of 2020 and 2021 (Test Period) delivery rates on a permanent basis (Application);

E. By Order G-96-20, the BCUC established the remainder of the regulatory process including written final and reply arguments;

F. By letter dated June 10, 2020, the Panel indicated specific factors it considered helpful for the parties to discuss as part of their final arguments;

G. On June 16, 2020, PNG(NE) filed an evidentiary update addressing an error that pertains to the modelling and calculation of certain IT-related capital additions and income tax deductions that impact 2020 and 2021 delivery rates;

H. By Order G-159-20, the BCUC re-opened the evidentiary record and amended the regulatory timetable to include BCUC and intervener IRs on the evidentiary update, and revised dates for intervener and reply arguments; and

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

NOW THEREFORE pursuant to sections 58 to 61 of the UCA and for the reasons provided in the decision issued concurrently with this Order, the BCUC orders as follows:

1. PNG(NE) is approved to recover the 2020 revenue requirement and the resultant delivery rate changes on a permanent basis, for the FSJ/DC and TR Divisions, effective January 1, 2020, as filed in the Application and subject to the following:
    - the adjustments identified by PNG(NE) during the regulatory process, as summarized in Appendix A to the decision issued concurrently with this Order; and
    - the directives and determinations outlined in this Order and the decision issued concurrently.
2. PNG(NE) is approved to recover on a permanent basis the 2020 RSAM rate rider set forth in the Application, effective January 1, 2020.
3. PNG(NE) is approved to recover the 2021 revenue requirement and resultant delivery rate changes on a permanent basis, for the FSJ/DC and TR Divisions, effective January 1, 2021, as filed in the Application and subject to the following:
    - the adjustments identified by PNG(NE) during the regulatory process, as summarized in Appendix A to the decision issued concurrently with this Order; and
    - the directives and determinations outlined in this Order and the decision issued concurrently.
4. PNG(NE) is approved to recover on a permanent basis the 2021 RSAM rate rider set forth in the Application, effective January 1, 2021.
5. PNG(NE) is directed to update the interest rate forecasts in its final regulatory schedules to reflect the BMO March 2020 forecast interest rates.
6. PNG(NE) is directed to file annually a report on significant capital projects with total costs of $500,000 or more as part of its Annual Report on or before April 30, including but not limited to the information outlined in section 2.2 of the decision issued concurrently with this Order. For any capital projects that are required to be included in the report but are not included due to timing reasons, PNG(NE) is directed to file with the BCUC details of these projects at least 30 days before construction commences.
7. PNG(NE) is approved to recover shared services charged by Pacific Northern Gas Ltd. (PNG) to PNG(NE) for the Test Period using the cost allocation and recovery methodology approved by Order G-114-13. This includes the Shared Corporate Services Costs allocated to PNG from its parent TriSummit Utilities Inc. (TSU), as follows:
    - FSJ/DC Division – $634,000 in 2020 and $624,000 in 2021; and
    - TR Division – $41,000 in 2020 and $42,000 in 2021.
8. PNG(NE) is approved to establish a new Shared Corporate Services Costs deferral account with a three-year amortization period and accruing interest at PNG(NE)'s Weighted Average Cost of Debt for each of the FSJ/DC and TR Divisions and to record their respective portions of the Shared Corporate Services Costs allocated to PNG from its parent, TSU, as follows:

- FSJ/DC Division – $377,000 in 2020 and $374,000 in 2021; and
- TR Division – $24,000 in 2020 and $25,000 in 2021.

9. PNG(NE) is directed to update its final regulatory schedules to reflect the new anticipated timing of the Automated Meter Reading project and the impact on Test Period forecast capital and operating cost(s)/savings, for both the FSJ/DC and TR Divisions, in accordance with section 3.2.1 of the decision.

10. PNG(NE) is approved to establish a rate deferral mechanism for each of its divisions, as set out in section 3.3.1 of the decision.

11. PNG(NE) is approved to establish an Accelerated Capital Cost Allowance deferral account for each of the FSJ/DC and TR Divisions, in accordance with section 3.3.2 of the decision.

12. PNG(NE) is approved to close the Studies deferral account.

13. PNG(NE) is directed to re-calculate the 2020 and 2021 revenue requirements and delivery rate changes reflecting the directives and determinations outlined in this Order and further described in the decision issued concurrently and file revised regulatory schedules with the BCUC for endorsement within 30 days of this Order.

14. PNG(NE) is directed to file the following information in its next RRA:
    - a progress update regarding the Pipeline Segment by Segment Risk Assessment and the Integrity Management Plan Audit outlined in section 2.1.1 of the decision;
    - a report detailing the information for specific IT projects outlined in section 2.1.2 of the decision; and
    - a breakdown of the Test Period costs and cost reductions related to the Automated Meter Reading project as outlined in section 3.2.1 of the decision.

15. PNG(NE) is directed to collect from/refund to customers the difference between the 2020 interim delivery rates and the 2020 permanent delivery rates over the balance of the Test Period together with the difference between the interim and permanent 2020 RSAM rate rider at the average prime rate of PNG(NE)'s principal bank for its most recent year.

16. PNG(NE) must inform all customers of permanent 2020 and 2021 delivery rates by way of written notice to be included with their next customer invoice after PNG(NE)'s compliance filing has been accepted by the BCUC.

17. PNG(NE) is directed to comply with all other directives contained in the decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 21st day of October 2020.

BY ORDER

Original signed by:

A. K. Fung, QC
Commissioner

Pacific Northern Gas (N.E.) Ltd.
2020–2021 Revenue Requirements Application
for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions

SUMMARY OF ADJUSTMENTS AND CORRECTIONS

During the regulatory process, PNG(NE) identified the following adjustments to its Test Period revenue requirements that it proposes to reflect in its final regulatory schedules.

Table 9 summarizes the proposed adjustments for the FSJ/DC Division.[181]

Table 9: PNG(NE) FSJ/DC Division - Summary of Adjustments / Corrections

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)**

[181] PNG(NE) Final Argument, Section 6, para 31, p. 13.

Table 10 summarizes the proposed adjustments for the TR Division.[182]

Table 10: PNG(NE) TR Division - Summary of Adjustments / Corrections

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)**

[182] PNG(NE) Final Argument, Section 6, paragraph 32, p. 14.

Pacific Northern Gas (N.E.) Ltd.
2020–2021 Revenue Requirements Application
for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions

SUMMARY OF PROPOSED DELIVERY RATE CHANGES

Tables 11 and 12 summarize the proposed 2020 and 2021 delivery rate changes for the FSJ/DC Division as filed for approval in the Application. The figures presented are subject to adjustments identified by PNG(NE) during the regulatory process, which are summarized in Appendix A to this decision, and the directives and determinations in this decision.[183]

Table 11: PNG(NE) FSJ/DC Division - Summary of Proposed Delivery Rate Changes for 2020

Customer Classification	Allocation of 2020 Revenue Deficiency	FSJ				DC			
		Test Year 2020 Delivery Charge	Proposed Rate Change from 2019 to 2020		Decision 2019 Delivery Charge	Test Year 2020 Delivery Charge	Proposed Rate Change from 2019 to 2020		Decision 2019 Delivery Charge
	$	$/GJ	$/GJ	%	$/GJ	$/GJ	$/GJ	%	$/GJ
Residential (Rate 1)	952,240	5.161	0.528	11.4%	4.633	4.963	0.528	11.9%	4.435
Commercial									
Small Commercial Firm (Rate 2)	465,990	3.963	0.354	9.8%	3.609	3.426	0.354	11.5%	3.072
Large Commercial Firm (Rate 3)	104,809	2.950	0.254	9.4%	2.696	2.402	0.254	11.8%	2.148
Commercial Transport (Rate 23)	18,622	3.196	0.310	10.7%	2.886	2.648	0.310	13.3%	2.338
Total Commercial	589,421								
Small Industrial Sales (Rate 4)	54,527	1.754	0.177	11.2%	1.577	2.022	0.177	9.6%	1.845
Industrial Transport									
Rate 6	27,526	1.9782	0.2048	11.5%	1.7734	n/a	n/a	n/a	n/a
Rate 7	n/a	n/a	n/a	n/a	n/a	0.2050	-	0.0%	0.2050
Rate 10	19,279	0.8751	0.1228	16.3%	0.7523	n/a	n/a	n/a	n/a
Total Industrial Transport	46,806								
TOTAL	**1,642,994**								

Table 12: PNG(NE) FSJ/DC Division - Summary of Proposed Delivery Rate Changes for 2021

Customer Classification	Allocation of 2021 Revenue Deficiency	FSJ				DC			
		Test Year 2021 Delivery Charge	Proposed Rate Change from 2020 to 2021		Test Year 2020 Delivery Charge	Test Year 2021 Delivery Charge	Proposed Rate Change from 2020 to 2021		Test Year 2020 Delivery Charge
	$	$/GJ	$/GJ	%	$/GJ	$/GJ	$/GJ	%	$/GJ
Residential (Rate 1)	1,045,056	5.735	0.574	11.1%	5.161	5.537	0.574	11.6%	4.963
Commercial									
Small Commercial Firm (Rate 2)	502,054	4.348	0.385	9.7%	3.963	3.811	0.385	11.2%	3.426
Large Commercial Firm (Rate 3)	114,118	3.227	0.277	9.4%	2.950	2.679	0.277	11.5%	2.402
Commercial Transport (Rate 23)	20,272	3.533	0.337	10.6%	3.196	2.985	0.337	12.7%	2.648
Total Commercial	636,443								
Small Industrial Sales (Rate 4)	59,406	1.947	0.193	11.0%	1.754	2.215	0.193	9.5%	2.022
Industrial Transport									
Rate 6	29,981	2.2012	0.2230	11.3%	1.9782	n/a	n/a	n/a	n/a
Rate 7	n/a	n/a	n/a	n/a	n/a	0.2050	-	0.0%	0.2050
Rate 10	21,023	1.0090	0.1339	15.3%	0.8751	n/a	n/a	n/a	n/a
Total Industrial Transport	51,005								
TOTAL	**1,791,910**								

[183] Exhibit B-2 (FSJ/DC), Section 1.4, pp. 7-8, Tables 2-3.

Table 13 summarizes the proposed 2020 and 2021 delivery rate changes for the TR Division as filed for approval in the Application. The figures presented are subject to adjustments identified by PNG(NE) during the regulatory process, which are summarized in Appendix A to this decision, and the directives and determinations in this decision.[184]

Table 13: PNG(NE) TR Division - Summary of Proposed Delivery Rate Changes

Customer Classification	Allocation of 2021 Revenue Deficiency	Test Year 2021 Delivery Charge	Proposed Rate Change from 2020 to 2021		Allocation of 2020 Revenue Deficiency	Test Year 2020 Delivery Charge	Proposed Rate Change from 2019 to 2020		Decision 2019 Delivery Charge
	$	$/GJ	$/GJ	%	$	$/GJ	$/GJ	%	$/GJ
Residential (Rate 1)	31,843	11.154	0.380	3.5%	28,089	10.774	0.339	3.2%	10.435
Commercial									
Small Commercial Firm (Rate 2)	11,176	8.775	0.279	3.3%	9,833	8.497	0.248	3.0%	8.249
Large Commercial Firm (Rate 3)	4,057	7.192	0.225	3.2%	3,604	6.966	0.200	3.0%	6.766
Total Commercial	15,233				13,437				
Industrial Transport									
CNRL	15,744	0.721	0.027	3.9%	14,047	0.694	0.024	3.6%	0.670
TOTAL	**62,820**				**55,572**				

[184] Exhibit B-2 (TR), Section 1.4, p. 8, Table 2.

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GLOSSARY AND ACRONYMS

Acronym	Description
AACE	Association for the Advancement of Cost Engineering
AltaGas	AltaGas Ltd.
AMR	Automated Meter Reading
Application	Amended application dated February 28, 2020
ARM	Asset record modernization
BC OGC	BC Oil and Gas Commission
BCOAPO et. al	British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and Tenants Resource and Advisory Centre
BCUC	British Columbia Utilities Commission
BMO	Bank of Montreal
BMO November 2019 Forecast	The 90 day treasury bill rates from the Bank of Montreal's November 22, 2019 forecast
CCA	Capital Cost Allowance
CIS	Customer information services
CPCN	Certification of public convenience and necessity
DC	Dawson Creek
ERP	Enterprise Resource Planning
FSJ	Fort St. John
GIS	Geographical information system
GJ	gigajoules
HRIS	Human resource information system
IMP	Integrity Management Program
IR	Information request
JDE	JD Edwards
KPMG	KPMG LLP
KPMG Report	An independent assessment of the Fair Value Estimate

Acronym	Description
O&M	Operations and maintenance
OMA	Maintenance and administrative and general
Original Application	Application dated November 29, 2019, seeks approval to amend delivery rates and Revenue Stabilization Adjustment Mechanism on an interim and refundable/recoverable basis, effective January 1, 2020
Pacific	AltaGas Utility Holdings Inc.
PNG	Pacific Northern Gas Ltd.
PNG(NE)	Pacific Northern Gas (N.E.) Ltd.
PNG(NE) 2018-2019 Decision	PNG(NE)'s 2018-2019 RRA Reasons for Decision accompanying Order G-164-18O&MA
PNG-West	PNG-West Division
PNG-West 2018-2019 Decision	PNG-West 2018-2019 RRA Reasons for Decision and accompanying Order G-151-18
PNG-West Decision	Order G-255-20 and accompanying decision on the PNG-West 2020-2021 Revenue Requirements Application dated October 14, 2020
RECAP	Reactivated Capacity Allocation Process
RRA	Revenue Requirements Application
RSAM	Revenue Stabilization Adjustment Mechanism
Test Period	Fiscal years 2020 and 2021
TR	Tumbler Ridge
TSU	Tri-Summit Utilities.
UAF	Unaccounted for gas
UCA	*Utilities Commission Act*
UltiPro	Ultimate Software

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EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated December 5, 2019 – Appointing the Panel for the review of Pacific Northern Gas (N.E.) Ltd. Application dated November 29, 2019 for 2020-2021 Revenue Requirements
A-2	Letter dated December 18, 2019 – Order G-331-19 establishing the preliminary regulatory timetable for the review of the Application
A-3	Letter dated April 6, 2020 – BCUC Information Request No. 1 to PNGNE for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions
A-4	Letter dated April 6, 2020 – BCUC Information Request No. 1 to PNGNE for the Tumbler Ridge Division
A-5	Letter dated April 27, 2020 – BCUC Order G-96-20 together with the regulatory timetable
A-6	Letter dated May 15, 2020 – BCUC Information Request No. 2 to PNGNE
A-7	**CONFIDENTIAL** Letter dated May 15, 2020 - BCUC Information Request No. to 1 PNGNE
A-8	Letter dated June 10, 2020 – BCUC issuing Final Arguments Request
A-9	Letter dated June 18, 2020 – BCUC Order G-159-20 amending the regulatory timetable
A-10	Letter dated June 24, 2020 – BCUC Information Request No. 1 to PNGNE on the Evidentiary Update
A-11	Letter dated July 16, 2020 – BCUC response to BCOAPO's request for extension
APPLICANT DOCUMENTS	
B-1	**PACIFIC NORTHERN GAS (N.E.) LTD. (PNGNE) -** Application dated November 29, 2019 for 2020-2021 Revenue Requirements
B-1-1	**CONFIDENTIAL** Letter dated November 29, 2019 – PNG 2020-2021 Revenue Requirements Application Confidential Appendix C
B-2	Letter dated February 28, 2020 – PNGNE Submitting Amended 2020-2021 Revenue Requirements Application
B-2-1	**CONFIDENTIAL** Letter dated February 28, 2020 – PNGNE Submitting Amended 2020-2021 Revenue Requirements Application Confidential Appendix C

B-2-2 Letter dated June 16, 2020 – PNGNE Submitting Notification of Error in Amended 2020-2021 Revenue Requirements Application

B-3 Letter dated April 29, 2020 – PNGNE Responses to BCUC Information Request No. 1

B-3-1 **CONFIDENTIAL** Letter dated April 29, 2020 – PNGNE providing Confidential Attachments to BCUC Information Request No. 1

B-4 Letter dated April 29, 2020 – PNGNE Responses to BCUC Information Request No. 1 for the Tumbler Ridge Division

B-5 Letter dated April 29, 2020 – PNGNE Responses to BCOAPO Information Request No. 1

B-6 Letter dated June 3, 2020 – PNGNE Submitting Responses to BCUC Information Request No. 2

B-6-1 **CONFIDENTIAL** Letter dated June 3, 2020 – PNGNE Submitting Confidential Responses to BCUC Information Request No. 2

B-7 Letter dated June 3, 2020 – PNGNE Submitting Responses to BCOAPO Information Request No. 2

B-8 Letter dated June 30, 2020 – PNGNE submitting responses to BCUC IR No.1 on Evidentiary Updated

INTERVENER DOCUMENTS

C1-1 **BC OLD AGE PENSIONERS' ORGANIZATION, ACTIVE SUPPORT AGAINST POVERTY, COUNCIL OF SENIOR CITIZENS' ORGANIZATIONS OF BC, DISABILITY ALLIANCE BC, TENANTS RESOURCE AND ADVISORY CENTRE, AND TOGETHER AGAINST POVERTY SOCIETY, KNOWN COLLECTIVELY IN REGULATORY PROCESSES AS "BCOAPO ET AL." (BCOAPO ET AL)** - Letter dated January 31, 2020 - Request for Intervener Status by Leigha Worth and Irina Mis, British Columbia Public Interest Advocacy Centre

C1-2 Letter dated April 15, 2020 – BCOAPO Submitting Information Request No. 1 to PNGNE

C1-3 Letter dated May 15, 2020 – BCOAPO Submitting Information Request No. 2 to PNGNE

C1-4 Letter dated July 15, 2020 – BCOAPO Submitting extension request to file Final Argument

INTERESTED PARTY DOCUMENTS

D-1 **FORTISBC ENERGY INC. (FEI) –** Submission dated December 23, 2019 – Request for Interested Party Status by Doug Slater