British Columbia Utilities Commission

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ORDER NUMBER
G-131-16

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

and

Pacific Northern Gas Ltd.
2016-2017 Revenue Requirements Application
for the PNG-West Service Area

BEFORE:
K. A. Keilty, Panel Chair/Commissioner
H. G. Harowitz, Commissioner
R. D. Revel, Commissioner

on August 10, 2016

ORDER

WHEREAS:

A. On August 1, 2013, the British Columbia Utilities Commission (Commission) issued Order G-114-13 concurrently with its decision on the Pacific Northern Gas Ltd. (PNG) 2013 Revenue Requirements Application (RRA) and directed PNG to, among other things, file its 2014 RRA for a period of two years. By Order G-168-13 dated October 10, 2013, the Commission varied Order G-114-13 to instead require PNG to file its RRA for a period of two years commencing in test years 2016 and 2017;

B. On November 30, 2015, PNG filed its 2016-2017 RRA with the Commission pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA) seeking, among other things, approval to increase 2016 delivery rates (Application);

C. By Order G-207-15 dated December 18, 2015, the Commission approved the delivery rates and the Rate Stabilization Adjustment Mechanism rider set forth in the Application on an interim and refundable basis, effective January 1, 2016. The Commission also established a preliminary regulatory timetable, including a procedural conference on January 29, 2016;

D. The British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO) and the International Brotherhood of Electrical Workers, Local 213 (IBEW 213) registered as interveners;

E. On January 26, 2016, the Commission issued Exhibit A-5 with a list prepared by Commission staff of specific items and/or supplemental information to be included in PNG's updated application;

F. The Procedural Conference was held on January 29, 2016. PNG and BCOAPO made appearances. As an alternative to the proposal in the Application, PNG proposed that it seek permanent 2016 and 2017 rates in its updated application. PNG also indicated that it would provide all of the items and supplemental information found in Exhibit A-5 in the updated application;

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G. By Order G-13-16 dated February 4, 2016, the Commission established a written public hearing process, which directed PNG to file its updated application on February 29, 2016, and included two rounds of Commission and intervener information requests, followed by final and reply arguments;

H. On February 29, 2016, PNG filed its updated application (Amended Application); and

I. The Commission has considered the Application, Amended Application, evidence and submissions of the parties.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, for the reasons for decisions attached as Appendix A to this order, the British Columbia Utilities Commission orders as follows:

1. Pacific Northern Gas Ltd.'s (PNG) request for recovery of the 2016 revenue requirement and resultant delivery rate changes presented in the Amended Application is approved on a permanent basis, effective January 1, 2016, subject to the adjustments identified by PNG in information requests and in argument as well as to the adjustments outlined in these directives.

2. The Rate Stabilization Adjustment Mechanism rider set forth in the Amended Application is approved on a permanent basis, effective January 1, 2016.

3. PNG's request for recovery of the 2017 revenue requirement and resultant delivery rate changes presented in the Amended Application is approved on a permanent basis, effective January 1, 2017, subject to the adjustments identified by PNG in information requests and in argument as well as to the adjustments outlined in these directives.

4. Directive 7(a) of Order G-104-15A is varied to eliminate the requirement to address the proposed recovery mechanism and amortization period for the 2015 revenue deficiency deferral account. PNG is directed to dissolve this deferral account.

5. The following changes and additions to PNG's regulatory accounts are approved:

    a. The creation of a new regulatory account to capture variances in forecast to actual pension and non-pension post-retirement benefits expenses bearing interest at PNG's weighted average cost of debt rate and amortized over a three-year period;

    b. No amortization of the Liquefied Natural Gas (LNG) Partners Option Fee Payment deferral account in 2016 or 2017. PNG is further approved to record in this deferral account for future disposition: additional legal fees of approximately $25,000 incurred in conjunction with the Interconnecting Pipeline between Kitimat and Douglas Channel, and General Service Tax of $155,000 which PNG has remitted to the Canada Revenue Agency;

    c. The dissolution of the Non-Regulated Business Recoveries deferral account and the Propane Air deferral account;

    d. Amortization of the 2012 Common Equity Thickness deferral account over two years, commencing January 1, 2016; and

    e. The establishment of a new regulatory account bearing interest at PNG's weighted average cost of debt to record the net impact on PNG's 2016 and 2017 rates arising from the Commission's decision on the FortisBC Energy Inc. Application for Common Equity Component and Return on Equity 2016.

6. PNG is approved to continue the use of the unaccounted for gas (UAF) volume deferral account on the basis that the UAF volume forecast for Test Year 2016 and Test Year 2017 are set at zero with PNG recording the variance between zero percent and a loss of up to 1.0 percent without having to seek further Commission approval. PNG must file an application with the Commission to obtain approval to record UAF losses above 1.0 percent in the UAF volume deferral account.

7. The Commission does not accept PNG's proposed method for developing Residential and Small Commercial customer load forecasts for the purpose of calculating the annual revenue deficiency/(sufficiency) and the resulting delivery rate changes in revenue requirement applications (RRAs). PNG is therefore directed to re-calculate these load forecasts using its existing load forecasting method, and to use those forecasts to calculate the 2016 and 2017 revenue deficiencies and resultant delivery rate changes. PNG must file the revised load forecasts and rate calculations in a compliance filing as part of its final regulatory schedules which are due to the Commission by no later than 30 days from the date of this order.

8. PNG is approved to recover $715,000 of the AltaGas inter-affiliate charge from ratepayers in each of Test Year 2016 and Test Year 2017. The Commission does not approve PNG's requested inflationary increase. PNG must comply with the Commission's determination in Order G-104-15A and accompanying Reasons for Decision directing PNG to conduct a full review and analysis of the AltaGas inter-affiliate charge to support the recovery of this charge from PNG's ratepayers, including the filing of reliable and objective evidence, such as a third-party consultant's report. PNG must file this evidence in its next RRA.

9. PNG is directed in future RRAs to file a copy of its Annual Pipeline Risk Mitigation Report or equivalent, together with any additional explanations or documentation required to support each significant category of forecast pipeline operating, maintenance and capital expenditure in each test period.

10. PNG's request to record the Electro-magnetic Acoustic Transducer (EMAT) In-line Inspection tool costs in a new rate base regulatory account is denied. PNG is directed to capitalize these costs in accordance with US Generally Accepted Accounting Principles. PNG must provide in the next RRA the plant account name and number and the depreciation rate being applied to the EMAT In-line Inspection tool costs.

11. PNG is directed to record the $500,000 payment from LNG Canada in a rate base regulatory account and is directed to provide the following information in its next RRA: (i) the actual cost of the Beaver Creek Line Lowering/Replacement project; (ii) the status of the General Services Agreement with LNG Canada; (iii) the balance of this newly established rate base regulatory account; and (iv) the proposed recovery of the balance in the regulatory account.

12. PNG is approved to record the additional option fees received in 2015 and 2016 under the amended Gas Transportation Services Agreement between PNG and EDF Trading Limited (EDFT GTSA) in the existing LNG Partners Option Fee Payment deferral account. PNG must file in its next RRA the relevant documents to clarify the legal status of the EDFT GTSA and must present a proposal for the disposition of the LNG Partners Option Fee Payment deferral account.

13. PNG is directed to re-calculate the 2016 and 2017 revenue deficiencies and delivery rate changes in a compliance filing and file revised regulatory schedules with the Commission reflecting the changes outlined in this order and further described in the attached reasons for decision by no later than 30 days from the date of this order.

14. PNG is directed to collect from/refund to customers the difference between the 2016 interim rates and the 2016 permanent rates over the balance of 2016. PNG must inform all customers of permanent rates by way of written notice to be included with their next customer invoice.

15. PNG is directed to file its next RRA for a period of two years encompassing a test period of 2018 and 2019.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of August 2016.

BY ORDER

Original Signed By:

K. A. Keilty
Commissioner

Attachment

British Columbia Utilities Commission

IN THE MATTER OF

**Pacific Northern Gas Ltd.
2016-2017 Revenue Requirements Application
for the PNG-West Service Area**

REASONS FOR DECISION

August 10, 2016

Before:
K. A. Keilty, Commissioner/Panel Chair
H. G. Harowitz, Commissioner
R. D. Revel, Commissioner

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1.0 INTRODUCTION

1.1 Background

Pacific Northern Gas Ltd. (PNG) filed an application with the British Columbia Utilities Commission (Commission) on November 30, 2015 pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA) seeking, among other things, approval to increase 2016 delivery rates (Application). By Order G-207-15 dated December 18, 2015, the Commission approved the delivery rates and the Rate Stabilization Adjustment Mechanism (RSAM) rider set forth in the Application on an interim and refundable basis, effective January 1, 2016.

On February 29, 2016, PNG filed an amended application with the Commission seeking approval, among other things, of permanent 2016 and 2017 delivery rate increases (Amended Application). In the Amended Application, PNG forecasts a revenue deficiency of approximately $1.321 million for the 2016 test year (Test Year 2016), and a revenue deficiency of approximately $1.008 million for the 2017 test year (Test Year 2017).[1]

The requirement for PNG to file a two-year revenue requirements application (RRA) arose from the PNG 2013 RRA Decision and accompanying Order G-114-13, in which the Commission directed PNG to file its 2014 RRA for a two-year period. The Commission stated that it "is of the view that filing future RRAs covering a time span of two years is both administratively efficient and prudent from a cost perspective."[2] By Order G-168-13 dated October 10, 2013, the Commission varied Order G-114-13 to instead require PNG to commence filing a two-year RRA for Test Years 2016 and 2017.

One significant change which occurred between the filing of the Application and the Amended Application is that on February 25, 2016, PNG was advised by the Douglas Channel (DC) Liquefied Natural Gas (LNG) Consortium that it had decided to halt further development of the DC LNG project due to unfavourable market conditions and worsening global energy price levels. The DC LNG Consortium further informed PNG that it intended to "discharge its obligations pursuant to the Companies' Creditor Arrangement Act (CCAA) proceedings." The impact of this change in circumstances is that the Amended Application has been revised to remove the capital costs associated with the Interconnecting Pipeline between Kitimat and Douglas Channel project which was approved by Order C-10-15. PNG further states that the capital and operating costs relating to the reactivation of pipeline assets and re-commissioning of compressors have been excluded from the Amended Application as a result of the project being halted.[3]

1.2 Regulatory process

As described above, by Order G-207-15 dated December 18, 2015, the Commission approved the delivery rates and RSAM rider set forth in the Application on an interim and refundable basis, effective January 1, 2016. The Commission also established a preliminary regulatory timetable which included a procedural conference to be held on January 29, 2016.

The British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO) and the International Brotherhood of Electrical Workers, Local 213 (IBEW 213) registered as interveners.

On January 26, 2015, the Commission filed Exhibit A-5 with a list prepared by Commission staff of specific items and/or supplemental information that PNG should include in the Amended Application.

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[1] Exhibit B-1-1, Amended Application, p. 3.
[2] Pacific Northern Gas Ltd. (PNG) Application for 2013 Revenue Requirements for the PNG-West Service Area (2013 RRA), Decision dated August 1, 2013, p. 10.
[3] Exhibit B-1-1, Amended Application, p. 3.

PNG and BCOAPO made appearances at the Procedural Conference on January 29, 2016. While PNG originally stated in the Application that it would seek approval of permanent 2016 rates and interim 2017 rates when filing the Amended Application, PNG proposed as an alternative at the Procedural Conference to seek permanent rates for both 2016 and 2017 in the Amended Application. PNG also indicated that it would provide all of the items and supplemental information requested in Exhibit A-5 in the Amended Application.

By Order G-13-16 dated February 4, 2016, the Commission established a written hearing process and amended the Regulatory Timetable to direct PNG to file the Amended Application on February 29, 2016, followed by two rounds of Commission and intervener information requests (IRs) and written final and reply arguments.

1.3 Approvals sought and issues arising

1.3.1 Approvals sought

In the Amended Application and subsequently updated in its final argument, PNG requests approval of the following:[4]

1. Approval, effective January 1, 2016, on a permanent basis pursuant to sections 58 to 61 of the UCA, for the recovery of the applied for revenue requirement and the resultant delivery rate changes presented in Exhibit B-1-1 under Tab Schedules, Tab 6, page 6 in the table entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2016" as set forth under the heading "Proposed Rate Changes for Rev. Def. ($/GJ)", subject to adjustments and undertakings as proposed through the information response process.
2. Approval, effective January 1, 2017, on a permanent basis pursuant to sections 58 to 61 of the UCA, for the recovery of the applied for revenue requirement and the resultant delivery rate changes presented in Exhibit B-1-1 under Tab Schedules, Tab 6, page 22 in the table entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2017" as set forth under the heading "Proposed Rate Changes for Rev. Def. ($/GJ)", subject to adjustments and undertakings as proposed through the information response process.
3. Approval to vary Directive 7(a) of Commission Order G-104-15A on PNG's application for no changes to 2015 delivery rates and changes to the 2015 Revenue Stabilization Adjustment Mechanism rider for the PNG-West service area, as PNG has determined that it will not seek recovery of the 2015 Revenue Deficiency deferral account as noted in Section 2.9 of the Amended Application.
4. Approval of the changes and additions to PNG's deferral accounts and amortization expenses for 2016 and 2017, pursuant to sections 58 to 61 of the UCA, as detailed in Section 2.9, Amortization, Exhibit B-1-1, and as shown in the Continuity of Deferred Charges tables set forth in this same exhibit under Tab Schedules, Tab 2, pages 15 through 18, and as detailed in response to certain information requests, including:
    i. Approval to create a new regulatory account to capture variances in forecast to actual pension and non-pension post-retirement benefits expenses bearing interest at PNG's weighted average cost of debt (WACD) rate and amortized over a three-year period;
    ii. Approval for no amortization of the LNG Partners Option Fee Payment deferral account in 2016 or 2017; plus approval to record additional legal fees of approximately $25,000 incurred in conjunction with the Interconnecting Pipeline between Kitimat and Douglas Channel; and

[4] Exhibit B-1-1, pp. 8, 62; Exhibit B-4, BCUC IR 45.1; PNG Final Argument, pp. 3–5.

approval to record general service tax (GST) of $155,000 that PNG has remitted to the Canada Revenue Agency (CRA) in this deferral account for future disposition;

iii. Approval to amortize the 2012 Common Equity Thickness deferral account over two years, commencing in Test Year 2016;

iv. Approval to remove the Non-Regulated Business (NRB) Recoveries deferral account;

v. Approval to remove the Propane Air deferral account;

vi. Approval to establish a new rate base regulatory account to capture the Electro-magnetic Acoustic Transducer (EMAT) In-line Inspection (ILI) tool costs, to be amortized over a five-year period; and

vii. Approval to establish a regulatory account bearing interest at PNG's WACD to record the net impact on PNG's 2016 and 2017 rates arising from the Commission's decision on the FortisBC Energy Inc. Application for its Common Equity Component and Return on Equity for 2016.

5. Approval to continue the unaccounted for gas (UAF) volume deferral account on the basis, pursuant to sections 58 to 61 of the UCA, that the UAF volume forecasts for Test Year 2016 and Test Year 2017 are set at zero with PNG recording the variance between zero percent and a loss of up to 1.0 percent without having to seek further Commission approval. PNG would be required to file an application with the Commission to obtain approval to record UAF losses above 1.0 percent in this deferral account.

1.3.2 Issues arising

A number of issues were identified through Commission and intervener IRs and in some cases further explored in parties' final and reply arguments. These issues are listed below and are each addressed in sections 2 through 5 of these Reasons for Decision.

- PNG's proposed load forecasting method for Residential and Small Commercial customers;
- Operating and administrative labour increases;
- Recovery of the AltaGas inter-affiliate charge;
- Other cost of service items, including:
    - Documentation supporting pipeline operating, maintenance and capital expenditures;
    - Forecast for meter reading costs; and
    - Guidelines for incentive payments;
- Treatment of EMAT ILI tool expenditures;
- Beaver Creek line lowering/replacement project;
- Treatment of additional option fee payments and disposition of the LNG Partners Option Fee Payment deferral account;
- Low income customer programs and affordability issues; and
- PNG's debt collection practices.

Commission determination

With the exception of the issues identified and outlined above, the Panel finds the requested approvals to be just and reasonable and accordingly approves them. The Panel also notes that other than the items identified in Section 1.3.2, no issues were raised by the parties with the remainder of PNG's requested approvals.

In the remainder of these reasons for decision, the Panel provides discussions and determinations where applicable on the identified issues.

2.0 PROPOSED VS. EXISTING METHOD FOR RESIDENTIAL AND SMALL COMMERCIAL LOAD FORECASTS

In the Amended Application and the amended application filed in the Pacific Northern Gas (N.E.) Ltd. [PNG (N.E.)] 2016-2017 RRA proceeding, PNG and PNG (N.E.) propose a new method for forecasting load for Residential and Small Commercial customers. This section addresses whether the proposed method should be approved by the Panel for the purpose of calculating PNG and PNG (N.E.)'s annual revenue deficiencies/ (sufficiencies) and the resultant delivery rate changes. The Panel notes that due to the identical nature of the proposed load forecasting method put forth in the PNG and PNG (N.E.) RRAs, the evidence, discussion and determinations made in this section pertain to both applications.

PNG states that the Commission, in the reasons for decision appended to Order G-140-14 approving the PNG-West 2014 Resource Plan, encouraged PNG to harmonize its methods for forecasting design day demand in a consistent manner across all of its regulatory filings.[5] PNG submits that in order to generate a meaningful forecast of annual demand, changes made to a peak day demand forecasting method must then also be reflected in an annual demand forecasting method. PNG has therefore responded to the Commission's suggestion by taking steps to harmonize both the annual and design day demand forecasting methods.[6]

Under both the existing and proposed forecasting methods, aggregate demand forecasts for Residential and Small Commercial customer classes are developed by multiplying the forecast of Use Per Accounts (UPAs) times the forecast for the total number of accounts.

The existing UPA forecasting method is based on the average of: (i) the most recent weather normalized actual UPA; and (ii) the UPA determined by extrapolation into the forecast year, of the most recent five years of weather-normalized actual UPA.[7] PNG's proposed UPA forecasting method multiplies the 2015 actual UPA by the percentage year-over-year forecast change in UPA trend from the residential end-use model (REUM) used in the PNG-West 2014 Resource Plan. The consolidated Resource Plan for PNG-West and PNG (N.E.) is filed every five years, with the next plan to be filed no later than April 2019.[8]

In response to BCOAPO IR 6.1, PNG provided the following graphs to illustrate the mechanism of the existing and the proposed UPA forecast method[9]:

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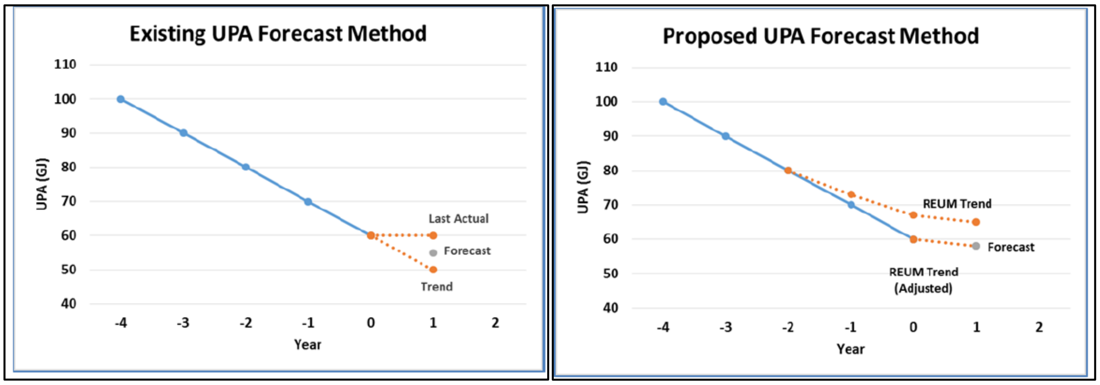
[5] PNG Final Argument, p. 5.
[6] Exhibit B-6, BCUC IR 47.1.
[7] Exhibit B-5, BCOAPO IR 6.1.
[8] PNG and Pacific Northern Gas (N.E.) Ltd. 2014 Resource Plan for the PNG-West Pipeline System and Resubmission of the DSM Portion of the 2012 Resource Plan for PNG (N.E.) Pipeline Systems, Order G-140-14 with Reasons for Decision dated September 16, 2014, p. 17.
[9] Exhibit B-5, BCOAPO IR 6.1.

Figure 1 – Existing versus proposed UPA Forecast Method



PNG anticipates that the cost and effort of generating forecasts using the proposed method is similar to those of the existing method.[10]

With regard to customer count forecasts, PNG submits that "the existing method is based on expert opinion supported by observations by field staff on residential and commercial construction activity in PNG's service areas."[11] Under the proposed method, the Residential and Small Commercial customer count forecasts are determined from the 2015 actual customers multiplied by the percentage year-over-year change in customers forecast in the 2014 Resource Plan.[12] In other words, the customer count forecast is based on the trend presented in the resource plan, where the trend in the customer forecast is revised along with the resource plan. PNG considers that a long-term trend provides a forward looking forecast that reflects demographic trends forecast by both provincial and federal agencies as well as by private institutions. In addition, PNG has reviewed the performance of its long-term customer forecasts as presented in the 2014 Resource Plan and updated its forecast using a weighted average of the Reference and All Electric scenarios in order to reflect better, recent changes in growth.[13] PNG presents these scenarios in Appendix B to the Amended Application. In response to BCUC IR 47.5, PNG compared the customer count forecast produced using the existing and the proposed methods, as shown in Tables 1 and 2 below.[14]

Table 1 – Residential customer count forecasts

	Test Year 2016		Test Year 2017	
Residential	Proposed Methodology	Existing Methodology	Proposed Methodology	Existing Methodology
Customer Count (Year End)	17,738	17,750	17,755	17,779
Customer Count (Weighted Average)	17,683	17,655	17,700	17,684

[10] Exhibit B-6, BCUC IR 47.8.
[11] Ibid., BCUC IR 47.3.
[12] PNG Final Argument, p. 6.
[13] Exhibit B-6, BCUC IR 47.4.
[14] Ibid., BCUC IR 47.5.

Table 2 – Small Commercial customer count forecasts

Small Commercial	Test Year 2016 Proposed Methodology	Test Year 2016 Existing Methodology	Test Year 2017 Proposed Methodology	Test Year 2017 Existing Methodology
Customer Count (Year End)	2,483	2,469	2,494	2,467
Customer Count (Weighted Average)	2,483	2,469	2,494	2,467

PNG presented an analysis using Mean Percent Error (MPE) and Mean Absolute Percent Error (MAPE) on the accuracy of the existing forecast method and the proposed forecast method by comparing the forecasts generated under the two methods against the actual results over the 2009 to 2015 period.[15] PNG submits that the proposed method, as compared to the existing method, results in a more accurate forecast when compared against historical actual demand.[16] PNG also submits that it considers that a forward looking forecast, such as the proposed method based on the REUM, can better reflect the anticipated changes to the mix of residential housing stock, the increased energy efficiency of new construction, and changes in the mix of standard and high efficiency furnaces and domestic hot water heaters in the residential stock. In addition, a forward looking forecast is not as susceptible to the year-over-year variability in the UPA over the historical period; the variability which is most often due to techniques used to estimate calendar-year consumption based on metered deliveries, to adjust to normal weather conditions, and to account for intra-year customer additions and removals.[17]

<u>Intervener final argument</u>

BCOAPO submits the following:

- Changes in use due to changes in the housing mix, average energy efficiency, upgrades in furnaces and hot water heating are all factors which contribute to changes in UPA and are inputs into, and reflected by, the actual normalized UPA which is used under the existing method.
- Direct use of historical actuals is preferable to the use of a long-run planning/resource document for forecasting near-term actual usage, and long-term projections are not suitable for forecasting demand and setting rates in a short-term test year.
- The MPE and MAPE evidence provided by PNG to claim that the proposed method is superior should be afforded zero weight by the Commission since the REUM being relied upon did not exist during the period 2010-2012.[18]

BCOAPO also notes that, while the new method does not appear to provide any theoretical or practical benefits for ratepayers, it does have very negative impacts on rates.[19]

<u>PNG reply argument</u>

PNG disagrees with BCOAPO's assessment that the extrapolation of the trend of historical actual UPA is preferable to the use of a long-run forecasting method applied to generate a test year forecast, and submits that while a historical trend reflects socio-economic and technical factors that collectively acted to influence UPA,

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15 Exhibit B-1-1, Appendix B, p. 6; Exhibit B-5, BCOAPO IR 6.2.
16 PNG Final Argument, p. 7.
17 Exhibit B-6, BCUC IR 47.1.
18 BCOAPO Final Argument, pp. 2–3.
19 Ibid., p. 3.

this same trend also reflects variations due to the adjustment to normal weather patterns, assumptions on the timing of customer additions and removals in order to estimate the average number of customers, and an adjustment for the year-end unbilled consumption; all of which introduce a degree of uncertainty and variability in the historical UPA to be used for trending purposes. PNG further submits that a forecast of the test year UPA based on a trend that reflects PNG's best forecast of socioeconomic and technical factors is not susceptible to the variability introduced by an extrapolation of historical UPA.[20]

With regard to the credibility of PNG's MAPE analysis that compares the accuracy of the proposed and the existing forecast methods, PNG concedes that, since the REUM was not created until 2013, PNG has had to apply it retrospectively to the period of 2010 to 2012 in order to generate statistics measuring its performance against actual results over a meaningful time period. PNG further states that it intends to continue to evaluate and evolve its forecasting techniques in order to achieve improved accuracies, as determined by a comparison with actual values.[21]

Commission determination

The Panel does not accept PNG's proposed method for developing Residential and Small Commercial customer load forecasts for the purpose of calculating the annual revenue deficiency/(sufficiency) and the resulting delivery rate changes in RRAs. PNG is therefore directed to re-calculate these load forecasts using its existing load forecasting method, and to use those forecasts to calculate the 2016 and 2017 revenue deficiencies and resultant delivery rate changes. PNG must file the revised load forecasts and rate calculations in a compliance filing as part of its final regulatory schedules which are due to the Commission by no later than 30 days from the date of these reasons for decision.

The Panel's conclusion that the existing method is superior for purposes of establishing rates is based upon a number of related considerations. First, the Panel agrees with BCOAPO that PNG's MPE and MAPE analysis is problematic given that the REUM which PNG relies upon did not exist during the period of 2010 to 2012. The Panel further notes that PNG concedes in its reply argument that because the REUM was not created until 2013, PNG had to apply it retrospectively to the period of 2010 to 2012. The Panel therefore considers this analysis to be insufficient and is not convinced of the improved predictive accuracy assertions that are based on the MPE and MAPE analysis. Second, from a general design perspective, the Panel is not convinced that methods/models that are useful in predicting longer term trends have application in predicting shorter-term results: rather, we consider the most recent actual performance data (i.e. the basis for the existing method) to be superior for short-term purposes. Third, in considering future RRAs, the Panel is concerned that the proposed method runs the risk of relying on outdated and less reliable inputs from the REUM if/as a particular RRA does not coincide with a recent update to the Long Term Resource Plan.

Furthermore, while this Panel agrees that there is value in having consistency in the load forecasts presented in different applications/analyses presented to the Commission, we do not see this as equivalent to arguing for use of the same tools in all instances. Rather, the pursuit of consistency means that the forecasts presented from one application to the next must be logically reconcilable.

The Panel also notes that, while agreeing in many instances with BCOAPO's analysis of the relative technical merits of the two forecast methods, the Panel does not consider BCOAPO's arguments regarding the relative rate impacts of one method versus the other as being relevant to the decision to continue using the existing method.

[20] PNG Reply Argument, pp. 2–3.
[21] Ibid., pp. 3–4.

3.0 COST OF SERVICE ISSUES

3.1 Operating, maintenance, administrative & general expenses – labour

The following sections discuss the increases to Test Year 2016 and Test Year 2017 expenses resulting from increases to PNG's operating labour as well as its administrative and general labour.

3.1.1 Operating labour

PNG forecasts an increase in operating labour for Test Year 2016 of $375,748 over the operating labour cost approved in the 2015 RRA (Decision 2015), which represents an increase of 6.4 percent.[22] The primary causes of the increase in labour costs are the hiring of an additional compressor station operator, the hiring of a new warehousing position, and inflationary increases.[23]

PNG's two existing compressor station operators became eligible for retirement as of January 1, 2014. One of these operators indicated informally that he will likely be retiring by the end of November 2016 and the other operator has indicated that he will likely retire by the end of December 2016.[24] PNG clarifies that it has hired two new compressor station operators in 2016 but has only budgeted for three full-time equivalents (FTEs) in Test Years 2016 and 2017.[25]

In response to BCUC IR 49.1, PNG stated that it would be appropriate to remove the cost of a third FTE compressor station operator in Test Year 2017 considering that both existing compressor station operators will likely be retiring by the end of 2016. PNG further stated that reducing the Test Year 2017 forecast by one FTE results in an overall labour reduction of $115,000.[26]

Test Year 2016 operating labour costs are also increasing due to the hiring of an additional warehousing labour position in the area of procurement and inventory.[27] In response to BCUC IR 52.2, PNG stated that the new employee officially started in December 2015 in order to ensure appropriate segregation of duties between the role of shipping and receiving of goods and the role of procurement and issuing of purchase orders, as required by the 2013 Committee of Sponsoring Organizations of the Treadway Commission Framework (2013 COSO Framework) for internal controls. The identification of the need for a separate position for shipping and receiving arose as part of the implementation of the new JD Edwards Enterprise Resource Planning (JDE ERP) system.[28]

PNG stated the following in support of the new shipping and receiving position:

> By having resources to manage the shipping and receiving duties and a buyer (procurement team leader) focusing on the procurement of goods and services, PNG expects to realize improved procurement through economies of scale on purchasing goods as well as through the monitoring and efficient use of shipping in our remote areas by ensuring trucks are full whenever possible.[29]

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[22] Exhibit B-4, BCUC IR 11.6.
[23] Exhibit B-1-1, pp. 35–36.
[24] Exhibit B-4, BCUC IR 9.1.
[25] Ibid., BCUC IR 9.6, 9.7.
[26] Exhibit B-6, BCUC IR 49.1, 49.1.1.
[27] Exhibit B-4, BCUC IR 11.6.
[28] Exhibit B-6, BCUC IR 52.2.
[29] Ibid.

Panel discussion

The Panel accepts the increases to operating labour for Test Years 2016 and 2017, subject to the adjustments identified by PNG in response to BCUC IRs and in PNG's final and reply arguments.

The Panel considers PNG's explanations for hiring the new compressor station operators to be reasonable and accepts PNG's proposal to reduce the Test Year 2017 forecast to include only two compressor station operators, as this more appropriately reflects the high likelihood that the two eligible operators will be retiring by the end of 2016.

The Panel further considers PNG's rationale for hiring the new warehousing position to be reasonable given the need for PNG to maintain adequate segregation of duties between shipping and receiving and procurement and issuing of purchase orders.

3.1.2 Administrative and general labour

PNG forecasts in the Amended Application an increase to general and administrative labour costs of $239,000 for Test Year 2016 compared to Decision 2015. Included in this forecast is the provision for a new executive position – the role of Vice President (VP) of Engineering. PNG states that the majority of this additional labour cost will be capitalized in anticipation that the VP of Engineering will spend approximately 80 percent of his time on capital projects.[30] PNG explains that the need for a VP of Engineering arises for two reasons: (i) to replace the capability being lost with the retirement of the company President, who is one of only two professional engineers employed at PNG; and (ii) to provide resources necessary to oversee the execution of capital expansion projects.[31]

PNG confirmed that it has included a full-year's salary in Test Year 2016 for the VP of Engineering; however, in response to BCUC IR 17.3, PNG stated that this position has not yet been filled and that a search would likely not commence until May 2016.[32] PNG subsequently stated it "does not consider it appropriate to include a full-year salary for the Vice President of Engineering in Test Year 2016" and instead proposed to include five months of salary in Test Year 2016 with the expectation that the VP of Engineering will be hired by August 2016.[33]

With regards to capitalizing 80 percent of the VP of Engineering's salary, PNG confirmed that this approach is consistent with its overhead capitalization policy, which was reviewed and approved by the Commission in PNG's 2011 RRA.[34]

Intervener final argument

BCOAPO submits that the Commission should consider two questions in relation to the new VP of Engineering position: "(i) Is this position necessary? (ii) If so, what is the appropriate treatment of the associated costs in 2016 (amount and capitalization) and 2017 (capitalization)?"[35]

With regards to the necessity of the position, BCOAPO points to PNG's response to BCUC IR 55.5 in which PNG stated that it intended for the new VP of Engineering to handle the following three major capital projects: the interconnecting pipeline between Kitimat and Douglas Channel, reactivation of pipeline assets, and re-

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[30] Exhibit B-1-1, pp. 42–43.
[31] Ibid., p. 42; Exhibit B-4, BCUC IR 27.2.
[32] Exhibit B-4, BCUC IR 17.3, 17.4.
[33] Exhibit B-6, BCUC IR 55.6, 55.7.
[34] Exhibit B-4, BCUC IR 27.2.
[35] BCOAPO Final Argument, p. 5.

commissioning of compressors. BCOAPO submits that it "understands that none of these three projects are proceeding as the Douglas Channel LNG Consortium has decided to halt further development of the Douglas Channel LNG Project, which calls into question the need for the position in 2016 (and possibly 2017)."[36]

BCOAPO submits that "if the BCUC does determine that it is prudent for PNG to hire this new proposed VP…including five months of the associated costs in the 2016 revenue requirement may be excessive." BCOAPO instead proposes that only three months of salary should be included in Test Year 2016. BCOAPO further submits that the Commission should consider approving a lower capitalization rate for the VP of Engineering's salary than the forecast rate of 80 percent and suggests 41.5 percent "since that was the percentage of the costs capitalized for the Vice President, Operations and Engineering – a position which appears similar to the proposed Vice President position – when PNG was acquired by AltaGas."[37]

<u>PNG reply argument</u>

PNG responds that it has provided sufficient evidence to support the hiring of the VP of Engineering to "focus on the oversight of both the operations and engineering functions in the organization, in particular in view of the lack of engineering depth at PNG and the past and imminent retirement of a number of experienced key personnel in operations."[38]

However, PNG agrees with BCOAPO's recommendation to include only three months of costs for the new VP of Engineering in Test Year 2016. PNG also states that it is amenable to BCOAPO's suggestion to capitalize a lower amount of the VP of Engineering's salary.[39]

Panel discussion

The Panel accepts the increases to administrative and general labour for Test Years 2016 and 2017, subject to the adjustments identified by PNG in response to BCUC IRs and in PNG's final and reply arguments.

The Panel accepts PNG's explanations as to the necessity of the VP of Engineering position and agrees that the Test Year 2016 forecast should be adjusted to include only three months of costs for this position. The Panel does not agree with BCOAPO's suggestion to reduce the capitalization rate applied to these labour costs to 41.5 percent to reflect the percentage capitalized for the previous Vice President, Operations and Engineering. There has been no evidence provided that the positions are similar enough to warrant an adjustment to the capitalization rate. Accordingly, the Panel expects PNG to capitalize the new VP of Engineering's salary in accordance with its approved capitalization policies and requests that PNG report on the actual capitalization rate as compared to the forecast capitalization rate for the VP of Engineering's salary as part of PNG's next RRA filing.

3.2 AltaGas inter-affiliate charge

Pursuant to Order G-192-11 issued on November 23, 2011, the Commission approved the acquisition by AltaGas Utility Holdings (Pacific) Inc. (AltaGas) of the issued and outstanding common shares of PNG. Prior to the AltaGas acquisition, PNG was a public reporting entity and thus was required to incur certain costs to maintain its public reporting status. Since the AltaGas acquisition, these costs are no longer incurred by PNG. Commencing in 2012, PNG has been charged an annual inter-affiliate fee from AltaGas to recover AltaGas' costs of providing services

[36] Ibid.
[37] Ibid., p. 6.
[38] PNG Reply Argument, p. 6.
[39] Ibid.

to PNG.[40] The inter-affiliate fees charged by AltaGas from 2012 through 2015 have been $404,000, $1,632,000, $1,550,000 and $2,106,000, respectively.[41] However, for years 2013 through 2015, the Commission denied PNG's request for full recovery of the inter-affiliate charges from ratepayers and instead approved the following amounts to be included in PNG's cost of service: $621,312 in 2013[42], $715,000 in 2014[43], and $715,000 in 2015.[44]

In the reasons for decision regarding the PNG-West 2015 Delivery Rates and RSAM Rider application (2015 Delivery Rates and RSAM Reasons for Decision), the Commission stated the following:

> In the absence of a study on actual charges, we cannot assess whether the affiliate charge should be increased or decreased. **The Panel has reviewed the evidence, and is not persuaded there has been any change of circumstance since 2014, to support a change to the 2013 inter-affiliate charge for 2015. Therefore, the Panel denies PNG's 2015 proposed Inter-Affiliate charge. Instead we allow PNG to recover $715,000 in the cost of service.**[45]

The Commission further stated:

> …PNG should file with the Commission evidence that would support a future Commission decision on whether it is appropriate to maintain, increase, or decrease this charge in future years. The Panel is specifically interested in objective evidence of the market value of the services provided. **Accordingly, the Panel directs PNG to conduct a full review and analysis of the AltaGas Inter-Affiliate Charges for 2016/2017 forecast, including the filing of reliable and objective evidence, such as a third-party consultant's report in the 2016/2017 RRA.**[46]

In the Amended Application, PNG does not request approval to recover the full 2016 and 2017 inter-affiliate charge from ratepayers and instead requests approval to recover $729,000 in 2016 and $745,000 in 2017, which PNG determines by applying a two percent inflationary increase to the amount approved in the PNG 2014 RRA Negotiated Settlement Agreement (NSA) of $715,000. In requesting only an inflationary increase to the previously approved inter-affiliate charge, PNG states that it has therefore chosen not to incur the costs associated with engaging a third-party consultant to develop the evidence requested by the Commission in Order G-104-15A. Instead, PNG provides its own internal review and analysis included as Appendix C to the Amended Application. PNG submits that the "evidence provided in this review is reliable and objective and supportive of the full extent of the expected inter-affiliate charges in 2016 and 2017, regardless of the significantly discounted amount which PNG is proposing for recovery in rates in 2016 and 2017."[47]

In Appendix C of the Amended Application, PNG states that it is "actively working with potential customers whose proposed projects will contract with PNG for natural gas supply and transportation" and that it is "optimistic that these projects will proceed and fully utilize available capacity" on the system. Once this occurs, PNG "expects to seek the full allocated cost recovery of the AltaGas inter-affiliate charges" and "at that time, if

[40] Exhibit B-1-1, Appendix C, p. 2.
[41] Ibid., Table 24, p. 45.
[42] PNG 2013 RRA Decision, p. 30.
[43] PNG Application for 2014 Revenue Requirements for the PNG-West Service Area, Negotiated Settlement Agreement, Appendix A to Order G-87-14, p. 11.
[44] PNG Application for No Changes to 2015 Delivery Rates and Changes to the 2015 Revenue Stabilization Adjustment Mechanism Rider for the PNG-West Service Area, Appendix A to Order G-104-15A Reasons for Decision dated June 22, 2015, p. 6.
[45] Ibid.
[46] Ibid.
[47] Exhibit B-1-1, p. 45.

desired by the Commission, PNG will engage an independent third-party consultant to assess the market value of the services provided by AltaGas to PNG in order to justify the application for full cost recovery."[48]

Table 2 on page 3 of Appendix C shows the breakdown of corporate costs allocated to PNG from AltaGas. In 2015, the allocation of Human Resources (HR), Information Technology (IT) and Procurement costs increased substantially from 2014. PNG states that this increase "is mainly due to the expansion of procurement and the implementation of company-wide enterprise resource planning (ERP) system." PNG further states: "Whilst the annual IT costs have increased due to higher annual operating cost associated with the ERP system, AltaGas is expected to realize company-wide benefit in resource and project development / planning / management, as well as various reporting functions when the ERP system is fully rolled out to all AltaGas business units."[49]

PNG converted to the JD Edwards Enterprise One (JDE) system as of January 1, 2015.[50] PNG confirms that the JDE project was led by AltaGas. PNG stated that it primarily utilized internal resources to work on the JDE conversion project and that AltaGas reimbursed PNG for external contractors hired to backfill a couple of positions in head office (paid directly by AltaGas) and in Terrace (reimbursement of $36,000), as well as reimbursing PNG for accommodation, transportation and meals incurred by PNG staff to attend testing sessions in Calgary ($73,000). However, as part of the conversion to JDE, PNG states it incurred "incremental third-party costs for Hyperion licenses, one contractor required to assist in the backlog of work in Plant Accounting and one temporary Accounts Payable clerk, for a total cost of approximately $100,000", which was not reimbursed by AltaGas.[51]

PNG further stated in response to BCUC IR 56.7 that while it "did not specifically track the total training time spent by employees" on JDE, it did track the "total hours spent on the JDE conversion, which was 4,544 hours (estimated at $430,000)", and that "of this total, AltaGas reimbursed PNG for 1,024 hours or $36,000 to backfill an Accounts Payable clerk position."

In response to BCUC IR 56.8, PNG stated that it is not able to estimate the annual costs of operating and maintaining the JDE system because it is run and operated by AltaGas, which forms part of the annual AltaGas inter-affiliate charge. Embedded in the inter-affiliate charge is a depreciation charge for the JDE system of approximately $110,000 related to 2016 and charges for the provision of JDE sustainment services by AltaGas personnel.

PNG previously incurred approximately $65,000 of annual costs to operate the Great Plains software, which was the system it used prior to the JDE ERP system conversion. PNG stated it has "purchased Hyperion licenses to facilitate the creation of required financial reports and expects to incur $15,000 for maintenance fees for these licenses in Test Year 2016."[52]

Commission determination

The Panel approves the recovery of $715,000 of the inter-affiliate charge from ratepayers in each of Test Years 2016 and 2017. As was the case in the 2015 RRA, **the Panel does not approve the inflationary increase requested by PNG**, as the Panel is no better able to assess the appropriate quantum of the inter-affiliate charge than was the Panel in the previous RRA, including whether this charge should be increased or decreased by an inflationary amount or other percentage. **Further, the Panel directs PNG to comply with the Commission's**

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[48] Exhibit B-1-1, Appendix C, p. 2.
[49] Exhibit B-1-1, Appendix C, pp. 3–4.
[50] Exhibit B-6, BCUC IR 56.4.
[51] Ibid., BCUC IR 56.5.
[52] Ibid., BCUC IR 56.8.

determination in Order G-104-15A and accompanying reasons for decision to conduct a full review and analysis of the AltaGas inter-affiliate charge to support the recovery of this charge from PNG's ratepayers, including the filing of reliable and objective evidence, such as a third-party consultant's report. PNG must file this evidence in its next RRA.

The Panel does not accept PNG's rationale for not filing "reliable and objective evidence", such as a third-party consultant's report, as directed by the Commission in the 2015 Delivery Rates and RSAM Reasons for Decision. The Commission in its Reasons for Decision specifically stated that "in the absence of a study on actual charges, we cannot assess whether the affiliate charge should be increased or decreased" and stated that "PNG should file with the Commission evidence that would support a future Commission decision on whether it is appropriate to maintain, increase, or decrease this charge in future years." The Commission did not include in its Reasons any indication that PNG's filing of this evidence was in any way correlated to the quantum of the inter-affiliate charge being requested by PNG for recovery from ratepayers.

While PNG asserts that the "evidence" provided in Appendix C to the Amended Application "provides reliable and objective support of the full extent of the expected inter-affiliate charges in 2016 and 2017", the Panel disagrees. Similar to the situation faced by the Commission in previous RRAs, PNG has failed in this application to provide clear information/evidence in support of an appropriate value to be placed on the services provided by AltaGas, particularly when considering the increased costs associated with PNG's affiliation with AltaGas, both direct and indirect.

The most recent example of an AltaGas-led initiative which has resulted in cost increases for PNG is the JDE ERP systems conversion. There is no evidence to indicate that had PNG still been operating as a standalone company it would have initiated the conversion from Great Plains to JDE. Based on PNG's response to BCUC IRs, it appears that the implementation of the JDE system required a large amount of PNG's own time and resources and that while AltaGas reimbursed PNG for some of the costs associated with the conversion, a larger proportion of the costs were borne by PNG. The Panel acknowledges PNG's statements that the JDE system is expected to provide significant benefits through economies of scale in purchasing which PNG would not be able to accomplish on a stand-alone basis; however, no attempt has been made by PNG to clearly set out the cost-benefit case for this expenditure.

3.3 Other cost of service issues

3.3.1 Documentation supporting pipeline operating, maintenance and capital expenditures

In the Amended Application and the amended application filed by PNG (N.E.) in its 2016-2017 RRA proceeding, PNG and PNG (N.E.) forecast a number of operating, maintenance and capital expenditures related to activities to assist in ensuring the long-term, safe and reliable operations of their pipelines. This section examines the sufficiency of the risk assessment documentation supporting these expenditures. The Panel notes that due to the similarity of issues identified in both RRA proceedings and certain pieces of relevant evidence being filed in each of the proceedings, the discussion and determinations made in this section pertain to both applications.

PNG stated that a 2014 BC Oil and Gas Commission (OGC) audit found PNG's existing risk evaluation and project prioritization system not up to industry best practices and not easily verifiable by a third party.[53] As an outcome of this OGC audit, PNG has a new forecast cost of $51,000 in Test Year 2016 to improve its high pressure risk assessment methodology.[54]

[53] Exhibit B-6, BCUC IR 48.1.2.
[54] Ibid., BCUC IR 48.10.1.

In response to BCUC IRs filed in the PNG (N.E.) 2016-2017 RRA proceeding, PNG (N.E.) stated that commencing in 2016, it will be using an outside facilitator for its annual risk review meeting and "significantly improving the documentation of the discussions and action items as required by its regulatory authorities." PNG (N.E.) also provided the minutes of the most recent Annual Integrity Management and Risk Review Meeting held on May 27, 2015.[55]

Commission determination

In future RRAs, PNG is directed to file a copy of its Annual Pipeline Risk Mitigation Report or equivalent, together with any additional explanations or documentation required to support each significant category of forecast pipeline operating, maintenance and capital expenditure in the test period. In the Panel's view, the pipeline risk assessment and project prioritization process is an important tool for use in assessing the necessity, efficiency, reasonableness and benefits associated with planned pipeline operating, maintenance and capital expenditures. The Panel notes that in some instances, information on new and/or larger expenditures related to ensuring the long-term, safe and reliable operations of PNG's pipeline were not fully addressed in the Amended Application and instead only came to light through IR responses. The Panel considers it important that PNG provide a more detailed explanation and justification in the next RRA and leverage the improved risk evaluation process commencing in 2016 to enhance the information filed in future RRAs, as this will allow for a more efficient review process and will help to clarify and explain changes in costs.

3.3.2 Meter reading expenditures

BCOAPO submits that a $47,000 decrease to meter reading costs (Account 712) is warranted, supported by actual meter reading costs in this account in 2015 being $47,000 less than approved as a result of PNG utilizing summer students to perform some meter reading tasks.[56]

In its reply argument, PNG states that "making use of lower-cost resources to fulfill these work requirements could be appropriate, subject to their availability and suitability."[57]

Panel discussion

The Panel does not accept BCOAPO's request to adjust the revenue requirements as suggested. No evidence has been presented that convinces the Panel that last year's savings will likely occur on a future recurring basis. The Panel considers PNG's Test Year 2016 and Test Year 2017 forecasts for meter reading expenditures to be reasonable based on the evidence gathered in this RRA proceeding.

3.3.3 Guidelines for incentive payments

BCOAPO requests in its final argument that the Commission "consider setting out some guidelines in its decision regarding appropriate incentive payment eligibility and amounts." BCOAPO particularly takes issue with the Short-Term Incentive Payments (STIP).[58]

PNG states in its reply argument that the addition of non-bargaining unit positions have caused the increases to STIP payments (other than inflationary increases) and that these additions have been reasonable and necessary.

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[55] Ibid., BCUC IR 44.5.
[56] BCOAPO Final Argument, pp. 6–7.
[57] PNG Reply Argument, p. 7.
[58] BCOAPO Final Argument, p. 6.

PNG also states that no changes have been made to the STIP program in the time period identified by BCOAPO (i.e. 2011 through 2017).[59]

Panel discussion

The Panel declines to issue any guidelines in this matter. The program has not been changed since 2011, and the Panel is satisfied with PNG's explanation that changes in total payments are reasonable and justified. Further, as no changes are being proposed as part of this Application, we see no need to address this issue in this proceeding.

4.0 CAPITAL EXPENDITURES AND DEFERRAL ACCOUNTS

4.1 Treatment of EMAT In-line Inspection expenditures

PNG forecasts $439,000 in 2016 and $81,000 in 2017 for utilization of the EMAT ILI tool in transmission pipelines. PNG states that "running this new tool in the transmission pipelines will provide precise data on the location and extent of any cracks detected so their assessment and repair can be better targeted, resulting in a more effective and efficient investigative dig program."[60]

In the Amended Application, PNG presented the EMAT ILI tool expenditures as capital costs. However, in response to BCUC IR 41.2, PNG submitted that it "should have considered recording this cost as an O&M charge rather than capitalizing the costs." PNG further submitted that "given the substantial cost of this initial use of the EMAT tool, the expected volatility of the costs of performing EMAT tool runs year-to-year, and the valuable information that will be obtained from its use…this cost should be recorded in a deferral account."[61]

PNG submitted in response to BCUC IR 68.1 that "US GAAP rules would not necessarily require the expensing of EMAT tool runs" because "US GAAP allows for the capitalization of major inspections in certain circumstances (e.g. airframe inspections) and, by analogy, PNG believes that the EMAT tool runs would qualify for capitalization." PNG explained that US GAAP rules require that the capitalized costs are amortized to the next major inspection and that PNG does not currently have a plant account with an appropriate depreciation rate for the EMAT costs. PNG therefore submitted that "not only would its requested deferral account treatment be administratively efficient…it would not be in contradiction with US GAAP."

PNG clarifies in its final argument that it is requesting approval to establish a new rate base deferral account to capture the annual EMAT ILI costs and to apply a five-year amortization period to this new deferral account.[62]

Commission determination

The Panel denies PNG's request to record the EMAT ILI tool costs in a new rate base regulatory account and directs PNG to capitalize the costs in accordance with US GAAP. PNG is further directed in the next RRA to provide the plant account name and number and the depreciation rate being applied to the EMAT ILI tool costs.

[59] PNG Reply Argument, p. 7.
[60] Exhibit B-1-1, pp. 88, 95.
[61] Exhibit B-4, BCUC IR 41.2.
[62] PNG Final Argument, p. 5.

The Panel is not persuaded that the use of a regulatory account is more administratively efficient. Further, given PNG's statements that US GAAP allows for these costs to be capitalized, the Panel considers this the most appropriate treatment, as it provides the same relief against lumpy and volatile expenses as a regulatory account. In the Panel's view, it is more appropriate to use regulatory accounts in circumstances where financial accounting principles do not allow for capitalization of costs and where the recording of such costs as operational expenses would result in large and volatile rate impacts. While the Panel acknowledges PNG's statement that it does not currently have a plant account with an appropriate depreciation rate, the Panel does not find this to be a compelling reason to depart from US GAAP in favour of the proposed new regulatory account.

4.2 Beaver Creek line lowering/replacement project

LNG Canada (LNGC) has requested that PNG lower its pipeline within the existing Right of Way (RoW) that crosses LNGC's property. LNGC plans to build a new diversion for Beaver Creek which drains into LNGC's property and crosses PNG's RoW resulting in ground instability. PNG states that it is currently in the process of completing contractual arrangements with LNGC and that LNGC has agreed to pay upfront for the associated construction costs of the line lowering/pipeline replacement project. PNG would then subsequently refund this payment to LNGC via a mechanism which will be determined as part of the Gas Sales Agreement (GSA) negotiations. PNG has recorded the upfront payment from LNGC as a Contribution in Aid of Construction (CIAC) in 2016.[63] PNG submits that the "negotiated arrangement with LNGC benefits both parties as PNG customers are assured they bear no additional risk up front and should the LNGC project proceed, LNGC would receive a credit for the [CIAC] towards its future service."[64]

PNG clarified that it has not yet received the CIAC from LNGC but that the payment will be received prior to PNG initiating construction, which is subject to coordination with LNGC. PNG further clarified that the terms of the GSA have not yet been finalized but at this time it is contemplated that the CIAC would be a contribution toward future service.[65]

Additionally, in response to BCUC IR 39.8, PNG submitted the following:

> In the event that LNGC is unable to enter into a GSA with PNG, the [CIAC] amount of $500,000 originally received from LNGC would be forfeited and remain with PNG to cover the costs of the line lowering. Excess [CIAC] amounts above PNG's actual costs incurred would be returned to LNGC. Similarly if the works' actual cost exceeded the amount of the [CIAC] and LNGC cancels their project, LNGC would be responsible for the difference incurred above the [CIAC] amount.[66]

PNG provided two alternatives to its proposed CIAC treatment. The first alternative is to follow the US GAAP treatment and record the amount as a security deposit. The second alternative is to record the $500,000 in a deferral account. PNG submitted that under either option, the amount paid by LNGC would either be amortized when the $500,000 is refunded as future gas sales are made to LNGC, or transferred to CIAC if the LNGC project does not move forward. PNG further submitted that its proposed treatment is the most beneficial option for ratepayers as it effectively provides a full rate of return on rate base on any non-refunded portion of the upfront payment from LNGC.[67]

[63] Exhibit B-1-1, p. 88.
[64] Exhibit B-4, BCUC IR 39.1.1.
[65] Ibid., BCUC IR 39.6, 39.7.
[66] Ibid., BCUC IR 39.8.
[67] Exhibit B-6, BCUC IR 67.2.

Commission determination

The Panel directs PNG to record the $500,000 payment from LNGC in a rate base regulatory account as opposed to recording the amount as a CIAC. The Panel further directs PNG in its next RRA to report on the following: (i) the actual cost of the Beaver Creek Line Lowering/Replacement project; (ii) the status of the GSA with LNGC; (iii) the balance of this newly established rate base regulatory account; and (iv) the proposed recovery of the balance in the regulatory account.

There appears to be a high degree of uncertainty regarding when, and if, the GSA with LNGC will be completed. Given this uncertainty, the Panel considers it most appropriate to record the upfront payment from LNGC in a regulatory account. In keeping with the fact that PNG's treatment of the upfront payment in the Amended Application was to record the amount as a CIAC, the Panel views it appropriate for the regulatory account to earn a return based on PNG's weighted average cost of capital and thus accords rate base treatment to this account.

4.3 LNG Partners Option Fee Payment deferral account

PNG requests approval for no amortization of its existing LNG Partners Option Fee Payment deferral account in 2016 or 2017. PNG also requests approval to record additional legal fees of approximately $25,000 incurred in conjunction with the Interconnecting Pipeline between Kitimat and Douglas Channel project and approval to record GST of $155,000 remitted by PNG to the CRA in this deferral account.[68]

The LNG Partners Option Fee Payment deferral account was established pursuant to Order G-174-08 to record option fee payments received from customers wishing to secure future transportation capacity on PNG's system. As at December 31, 2014, $7.5 million of option fees had been received by PNG. Of this amount, approximately $6.9 million have been credited (i.e. amortized) to customers as a mechanism to reduce PNG's annual revenue deficiencies.[69]

Pursuant to Order G-5-15, the Commission approved an assignment of the LNG Partners option, with certain amendments, and a new Gas Transportation Services Agreement (GTSA) between PNG and EDF Trading Limited (EDFT). In accordance with the EDFT GTSA, PNG has received the following additional option fees: (i) $2 million received upon Commission approval of the EDFT GTSA; and (ii) $166,667 per month commencing July 1, 2015, with the last monthly payment received in February 2016. PNG has not recorded any additional monthly option fee payments since February 2016 due to a letter received on February 25, 2016 indicating that the planned Dawson Creek LNG Project had been halted.[70]

The Commission directed PNG as part of Order G-104-15A to address the proposed recovery mechanism and amortization period of the LNG Partners Option Fee Payment deferral account and address the appropriate treatment of the additional option fees received in 2015 and 2016.

PNG discussed the pros and cons for PNG and for ratepayers of recording the option fees received under the EDFT GTSA as deferred revenue in accordance with US GAAP compared to adding these option fees to the existing deferral account. PNG submitted that treating the option fees as deferred revenue would result in "potential significant volatility in customer rates" because "[n]ow that it has been determined that the project is not moving forward, PNG would have to recognize all of the option fees as revenue in 2016 which would result

[68] PNG Final Argument, pp. 4–5.
[69] Exhibit B-1-1, Appendix D, p. 8.
[70] Exhibit B-1-1, p. 68.

in a significant decrease in customer rates in 2016 and a subsequent significant increase in customer rates in 2017."[71]

Commission determination

The Panel approves PNG's requests for no amortization of the LNG Partners Option Fee Payment deferral account in 2016 and 2017 and to record the additional legal fees of approximately $25,000 and the GST remittance of $155,000 in the existing deferral account. The Panel further approves the recording of the additional option fees received in 2015 and 2016 under the amended EDFT GTSA in the existing LNG Partners Option Fee Payment deferral account. The Panel is still unclear as to the status of the EDFT GTSA and in consideration of this remaining uncertainty considers it appropriate for the option fee payments to remain in the deferral account and not be amortized or otherwise drawn down at this time. **PNG must file in its next RRA the relevant documents to clarify the legal status of the EDFT GTSA and must present a proposal for the disposition of the LNG Partners Option Fee Payment deferral account.**

5.0 OTHER MATTERS

BCOAPO raises a number of additional concerns in its submissions, each of which is dealt with in this section.

5.1 Affordability

BCOAPO requests that PNG include a discussion of steps it plans to take regarding affordability issues in PNG's next rate design application.[72]

PNG opposes this request in its reply argument and states that this would result in increased costs and resources which would further increase the cost of service for PNG customers. PNG also argues that it does not believe that the UCA permits discrimination in rates in favour of low income residential ratepayers.[73]

Panel discussion

The Panel considers this issue to be out of scope in a revenue requirements application, and hence does not make any request of PNG in this regard.

5.2 Debt collection policies

BCOAPO presents a case in its final argument that PNG's current debt collection practices are at a minimum not appropriate and perhaps not legal, and therefore asks that the Commission order PNG to stop the collection practices that BCOAPO finds objectionable.[74]

PNG opposes this request in its reply argument, arguing that BCOAPO is "essentially challenging the content of PNG's Commission-approved tariff."[75]

PNG states that BCOAPO's request is not appropriate in the context of this RRA due to the fact that the RRA is not dealing with issues of PNG's tariff terms and conditions. PNG states that its tariff was most recently

[71] Exhibit B-6, BCUC IR 63.1.
[72] BCOAPO Final Argument, p. 7.
[73] PNG Reply Argument, pp. 7–8.
[74] BCOAPO Final Argument, pp. 7–10.
[75] PNG Reply Argument, p. 8.

approved in Order G-127-11 and that BCOAPO's request constitutes a reconsideration of that order without an accompanying application filed by BCOAPO with the Commission.[76]

Panel discussion

The Panel agrees with PNG that this request is out of scope of this revenue requirements hearing, and therefore refrains from issuing any directive to PNG in this regard.

[76] Ibid.