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ORDER NUMBER
G-151-18

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

and

Pacific Northern Gas Ltd.
2018–2019 Revenue Requirements Application

BEFORE:
D. A. Cote, Commissioner/Panel Chair
B. A. Magnan, Commissioner
A. K. Fung, QC, Commissioner

on August 15, 2018

ORDER

WHEREAS:

A. On November 30, 2017, Pacific Northern Gas Ltd. (PNG) filed its 2018–2019 Revenue Requirements Application (RRA) for its West Division (PNG-West) with the British Columbia Utilities Commission (BCUC) pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA) seeking approval to, among other things, increase 2018 and 2019 delivery rates (Application);

B. By Order G-191-17 dated December 19, 2017, the BCUC approved the following delivery rate increases, amongst others, on an interim and refundable/recoverable basis effective January 1, 2018:

   1. 1.5 percent increase from $12.372/GJ to $12.557/GJ for residential service;
   2. 1.4 percent increase from $10.416/GJ to $10.562/GJ for small commercial service; and
   3. 1.9 percent increase from $7.090/GJ to $7.222/GJ for Granisle propane service;

   Order G-191-17 also approved a decrease in the Rate Stabilization Adjustment Mechanism (RSAM) rate rider on an interim and refundable/recoverable basis applicable to residential, small commercial and commercial transport customers from $1.656/GJ to $0.551/GJ and established a regulatory timetable including a February 28, 2018 deadline for PNG-West to file its updated application (Amended Application);

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.*) registered as an intervener in the proceeding;

D. By Order G-30-18 dated February 2, 2018, the BCUC established a written public hearing process, including two rounds of BCUC and intervener information requests (IRs), followed by final and reply arguments;

E. On February 28, 2018, PNG filed its Amended Application;

F. On June 26, 2018, the BCUC reopened the evidentiary record and issued one round of Panel IRs to PNG-West and requested submissions from parties on the need for additional arguments on the specific content of the responses to the Panel IRs. The BCUC did not receive any requests for additional arguments; and

G. The BCUC has considered the Application, Amended Application, evidence and submissions of the parties.

NOW THEREFORE pursuant to sections 59 to 61 of the UCA and for the reasons for decision attached as Appendix A to this order, the BCUC orders as follows:

1. PNG's request for recovery of the 2018 revenue requirement and resultant delivery rate changes presented in the Amended Application is approved on a permanent basis, effective January 1, 2018, subject to the adjustments identified by PNG in IRs and in argument as well as to the adjustments outlined in these directives.

2. The 2018 RSAM rider set forth in the Amended Application is approved on a permanent basis, effective January 1, 2018.

3. PNG's request for recovery of the 2019 revenue requirement and resultant delivery rate changes presented in the Amended Application is approved on an interim and refundable/recoverable basis, effective January 1, 2019, subject to the adjustments identified by PNG in IRs and in argument as well as to the adjustments outlined in these directives. The 2019 rates will remain interim pending the BCUC review of the negative salvage compliance filing and the BCUC's determination on the timing of the phase-in period for the negative salvage accounting.

4. The 2019 RSAM rider set forth in the Amended Application is approved on a permanent basis, effective January 1, 2019.

5. PNG is directed to file a proposal within 60 days of the date of this order for a report to the BCUC, to be filed annually, which outlines its future construction of extensions and new facilities as well as any significant system modifications or additions that are planned. The proposal is to be filed in accordance with section 2.1 of the reasons for decision attached to this order.

6. PNG is directed to prorate the 2018 forecast labour costs for each of the new positions, as outlined in section 3.1.1 of the reasons for decision attached to this order, in its final regulatory schedules to be included in its compliance filing made pursuant to directive 20 of this order.

7. PNG is directed to file an updated Code of Conduct and Transfer Pricing Policy with the BCUC for approval by December 31, 2018.

8. PNG is directed to submit a compliance filing regarding the Copper River MP Repair project within 30 days of the date of this order, to include project status, schedule, costs and any budget variances, any difficulties that the project has encountered and any material changes to the identified risks. PNG is also directed to file the Class 3 estimate for the project as soon as reasonably practicable but no later than within 30 days of the date of this order.

9. PNG is directed to file a report in its next RRA on the Geographic Information System and Asset Record Modernization projects and related projects outlining detailed project benefits and any anticipated cost savings to be achieved.

10. PNG is directed to analyse its capital planning and procurement process and report in the next RRA on the measures it has taken to minimize budgeting errors and omissions, facilitate the scheduling process and improve its procurement process to provide for timely completion of planned capital projects.

11. The following changes and additions to PNG's deferral accounts are approved:

    a. The creation of a new deferral account bearing interest at PNG's short-term interest rate to levelize the impact of the combined net revenue sufficiency for 2018 and 2019 to be fully amortized in 2019;

    b. The transfer of the 2016 unaccounted for gas (UAF) losses above 1.0 percent totalling 183,336 GJs valued at $353,288 before tax from the temporary UAF deferral account to the UAF volume deferral account to be recovered from customers via the Company Use rider, and dissolution of the temporary UAF deferral account;

    c. No amortization of the Liquefied Natural Gas (LNG) Partners Option Fee Payment deferral account in 2018 or 2019. PNG is further approved to record in this deferral account for future disposition: Goods & Services Tax of $321,000 which PNG has remitted to the Canada Revenue Agency, and annual reservation payments of $14,000 as stipulated per the Gas Reservation and Pipeline Lowering Agreement with LNG Canada. PNG is denied the right to any carrying charges on the GST amount of $321,000 for the 2016-2017 time-period;

    d. The establishment of a new deferral account bearing interest at PNG's short-term interest rate to record the proposed revenue sharing arising from the PLP Project Amendment to be fully amortized in 2019; and

    e. The dissolution of the Investigative Digs – Pre-2013 deferral account, the Common Equity Thickness – 2012 deferral account, the Legacy Deferred Income Taxes deferral account, the non-pension post-retirement benefit (NPPRB) Regulatory Asset Deferral account and the LNG Canada payment deferral account.

12. PNG is approved to continue the use of the UAF volume deferral account on the basis that the UAF volume forecast for Test Year 2018 and Test Year 2019 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 BCUC approval. PNG must file an application with the BCUC to obtain approval to record UAF losses above 1.0 percent in this deferral account.

13. PNG's request to record the Electro-magnetic Acoustic Transducer (EMAT) In-line Inspection tool costs in a new rate base deferral account is denied. PNG is directed to capitalize these costs in accordance with US Generally Accepted Accounting Principles in Account 465 and depreciate over a period of 10 years.

14. PNG's request to record the compressor engine overhaul costs in a new rate base deferral account is denied. PNG is directed to capitalize these costs in accordance with US Generally Accepted Accounting Principles and depreciate over a period of 5 years once those assets are placed into service. PNG is directed to provide the plant account name applicable to the compressor engine overhaul costs in its compliance filing made pursuant to directive 20 of this order.

15. PNG is approved to apply the depreciation rates based on the findings of the depreciation study set forth in section 2.8 of the Amended Application, effective January 1, 2018, subject to the adjustments outlined in these directives.

16. PNG's proposal to exclude provisions for negative salvage values from depreciation expense is denied. PNG is directed to file with the BCUC within 45 days of the date of this order a report on the transition to negative salvage accounting as described in section 6.2.1 of the reasons for decision attached to this order.

17. PNG is directed to incorporate positive salvage values for Account 485 in its depreciation rates to coincide with the timing and methodology for incorporation of negative salvage in depreciation rates.
18. PNG is directed to amortize land rights in accordance with the recommendations made in the Concentric Advisors ULC Depreciation Report, effective January 1, 2019.
19. PNG is approved to recover $730,000 of the AltaGas inter-affiliate charge from ratepayers in Test Year 2018 and $743,000 in Test Year 2019 on a consolidated basis, reflecting inflationary increases over the 2017 approved amount of $715,000.
20. PNG is directed to re-calculate the 2018 and 2019 revenue requirements and delivery rate changes in a compliance filing and file revised regulatory schedules with the BCUC 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.
21. PNG is directed to collect from/refund to customers the difference between the 2018 interim rates and the 2018 permanent rates over the balance of 2018. PNG must inform all customers of permanent rates by way of written notice to be included with their next customer invoice.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of August 2018.

BY ORDER

Original signed by:

D. A. Cote
Commissioner

Attachment

Pacific Northern Gas Ltd.

2018–2019 Revenue Requirements Application

Reasons for Decision

August 15, 2018

Before:
D. A. Cote, Commissioner/Panel Chair
A. K. Fung, QC, Commissioner
B. A. Magnan, Commissioner

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1.0 Introduction

1.1 Background

Pacific Northern Gas (PNG) is a wholly owned subsidiary of AltaGas Utility Holdings (Pacific) Inc. which is in turn a wholly-owned subsidiary of AltaGas Ltd. (AltaGas). Its western division, PNG-West, 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 Prince Rupert and Kitimat. Along this corridor PNG-West serves 20,400 natural gas customers with an additional 150 propane customers being served in the community of Granisle, BC. In addition, PNG is the parent company of Pacific Northern Gas (N.E.) Ltd. (PNG(NE)) which operates a gas processing plant and natural gas distribution system providing service to 21,400 natural gas customers in Fort St John (FSJ), Dawson Creek (DC), and Tumbler Ridge (TR). A system map encompassing PNG-West and PNG(NE) operations is illustrated in Figure 1[1]

Figure 1 - PNG System Map

For purposes of clarity the term "PNG" will be used within these reasons for decision when the Panel is referring to general corporate direction while the term "PNG-West" will be used with reference to requests for approval made during the proceeding and any operational and non-corporate issues related to this division as discussed within the evidentiary record.

On November 30, 2017, PNG-West submitted its 2018-2019 Revenue Requirements Application (RRA) to the British Columbia Utilities Commission (BCUC) seeking approval to amend its rate schedules for the PNG-West Division to be effective January 1, 2018 (Original Application). On December 19, 2017, the BCUC issued Order G-191-17 approving interim delivery rates of $12.557/GJ for residential service, $10.562 for small commercial service and $7.222 for Granisle propane service. In addition, the Rate Stabilization Adjustment Mechanism (RSAM) rate rider of $0.551/GJ (down from $1.656/GJ) was approved. These interim approvals were effective January 1, 2018. In addition, this Order established a preliminary regulatory timetable covering the period up to February 28, 2018, when PNG-West was scheduled to file an updated application (Amended

[1] Exhibit B-1-1, p. 2.

Application). PNG-West states that the Amended Application generally includes all of the Original Application with revisions arising from normal evidentiary update information inclusive of revised demand forecasts, updated cost forecasts in addition to the impact of 2017 actual operating results on rate-base items.[2] Henceforth, any further reference to the Application will include the amendments set out in the Amended Application as applicable.

1.2 Regulatory process

On February 2, 2018, the BCUC by Order G-30-18 established a regulatory timetable and a written hearing as supported by the parties. The timetable included two rounds of information requests (IRs) as well as final argument from the parties and reply argument from the applicant.

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.*) registered as the sole intervener.

Following the scheduled process and submission of reply argument by PNG-West, the Panel issued a Panel IR requesting further information and clarification of a number of issues. Parties were provided the opportunity to file additional argument to address the specific content of the responses to the Panel IRs. The BCUC did not receive any requests for additional argument.

1.3 Approvals sought

PNG-West seeks an Order from the BCUC granting the approvals as described in the following:[3]

1. Approval, effective January 1, 2018, on a permanent basis pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA), for the recovery of the applied for revenue sufficiency and the resultant delivery rate changes presented under Tab Schedules, Tab 6 in the table entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2018" as set forth under the heading "Proposed Rate Changes for Rev. Def. ($/GJ)", subject to adjustments and undertakings identified through the regulatory review process.
2. Approval, effective January 1, 2019, on a permanent basis pursuant to sections 58 to 61 of the UCA, for the recovery of the applied for revenue sufficiency and the resultant delivery rate changes presented under Tab Schedules, Tab 6 in the table entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2019" as set forth under the heading "Proposed Rate Changes for Rev. Def. ($/GJ)", subject to adjustments and undertakings identified through the regulatory review process.
3. Approval of PNG-West's proposal to create a short term interest bearing rate deferral account in 2018 to levelize the impact of the combined net revenue deficiencies for 2018 and 2019 to be fully amortized in 2019.
4. Approval of the changes and additions to PNG-West's deferral accounts and amortization expenses for 2018 and 2019, pursuant to sections 58 to 61 of the UCA, as detailed in Section 2.9 – Amortization, and as shown in the Continuity of Deferred Charges tables set forth in this same exhibit under Tab Schedules, Tab 2, including:
    a. Further to BCUC Order G-104-17, approval pursuant to sections 58 to 61 of the UCA, to move the 2016 unaccounted for gas (UAF) losses above 1.0 percent from the temporary UAF deferral

[2] Exhibit B-1-1, p. 1.
[3] PNG Final Argument, pp. 2–5.

account to the UAF volume deferral account and to be recovered from customers via the Company Use rider, PNG-West's historic mechanism for recovering/refunding UAF losses/gains;

b. Approval for no amortization of the LNG Partners Option Fee Payment deferral account in 2018 or 2019; plus approval to record GST of $321,000 that PNG-West has remitted to the Canadian Revenue Agency (CRA) in this deferral account, and approval to record future option fees received in this account. PNG-West modified the latter request during the IR process and no longer seeks approval to record all future option fees received in this account. Instead, PNG-West seeks approval only to record in this account annual reservation payments of $14,000 as stipulated per the Gas Reservation and Pipeline Lowering Agreement with LNG Canada;

c. Approval for a new rate base deferral account for Electro-magnetic Acoustic Transducer (EMAT) In-line Inspection (ILI) costs, to be applied on a go-forward basis with an amortization period of 10 years;

d. Approval for a new rate base deferral account to record compressor engine overhaul costs and commence amortization once the asset is put into service over a 5-year period;

e. Approval to eliminate the Investigative Digs – Pre 2013 deferral account;

f. Approval to eliminate the Common Equity Thickness – 2012 deferral account;

g. Approval to eliminate the Legacy Deferred Income Taxes deferral account;

h. Approval to eliminate the NPPRB Regulatory Asset deferral account;

i. Approval to eliminate the LNG Canada payment deferral account that was not required; and

j. Approval to record PNG's proposed revenue sharing which arose from the PLP Project Amendment and fully amortize it in 2019.

5. Approval of the depreciation expense based on the findings of a new depreciation study as set forth in Section 2.8 – Depreciation of the Application.

6. Approval to continue the UAF volume deferral account on the basis, pursuant to sections 58 to 61 of the UCA that the UAF volume forecast for Test Year 2018 and Test Year 2019, are set at zero with PNG-West recording the variance between zero percent and a loss of up to 1.0 percent without having to seek further BCUC approval. PNG-West would be required to file an application with the BCUC to obtain approval to record UAF losses above 1.0 percent in this deferral account.

7. PNG-West is also seeking Commission approval of a 2018 debit RSAM rate rider equal to $0.252/GJ and a 2019 credit RSAM rate rider equal to $(0.327)/GJ as shown in Exhibit B-1-1 at Tab Schedules, Tab Rates, pages 14 and 30, respectively.[4]

1.4 Issues arising and organization of the decision

There were a number of issues arising within the proceeding, each of which will be identified and addressed in the following sections.

Section 2.0 will deal with issues that are more general in nature. These include a discussion of sections of the UCA pertaining to when a Certificate of Public Convenience and Necessity (CPCN) is required with specific reference to a number of capital expenditures planned and reviewed within this RRA. This section will also address PNG-West's proposed rate deferral mechanism as a means of smoothing rate changes over 2018 and 2019.

[4] PNG Final Argument, p. 27.

Section 3.0 will focus on cost of service issues including those related to operating, maintenance, administrative and general expenses, the proposal for an increase in the AltaGas inter-affiliate charge as well as PNG's Code of Conduct and Transfer Pricing Policy.

Section 4.0 will address issues related to PNG-West's proposed capital expenditure projects. In addition, the Panel considers issues related to capital expense reporting and variances in recent years.

Section 5.0 will examine issues related to deferral accounts including the handling of 2016 UAF losses, unanticipated LNG losses for Prince Rupert and PNG-West's proposal for handling of a GST payment of $321,000 which it failed to bring before the BCUC in its 2016-2017 RRA.

Section 6.0 will address the Depreciation Study completed by Concentric Advisors ULC (Concentric) and discuss issues related to the inclusion of positive and negative salvage as well as the depreciation of land rights.

Other matters including service quality metrics and capital structure will be addressed in Section 7.0.

With the exception of those issues identified and discussed in the following sections, the Panel finds the 2018-2019 RRA filing and associated approval requests to be just and reasonable, and accordingly approves them.

2.0 General issues

2.1 CPCN requirements

PNG-West has filed a listing of capital expenditures for 2018 totalling $15.218 million subject to adjustments identified during the IR process.[5] This capital request far exceeds recent actual capital expenditures that have ranged from $3.258 million to $4.609 million from 2013 through 2017.[6] There are a number of large projects planned for 2018, some of which contribute significantly to the 2018 capital expenditures. Notable among these are the following:

Table 1: Notable Planned Projects for 2018[7]

	2018 Cost	2019 Cost	Total Expected Cost
Geographic Information System	$441,000	$671,000	$1.5 million[8]
Copper River MP 250 Repair	$5.7 million		$5.8 million[9]
Ridley Island Prop Export Term (RIPET)	$4.4 million		$4.5 million[10]

Each of these represents a substantial investment and collectively will have a significant impact on rates going forward.

[5] Exhibit B-1-1, p. 85; PNG Final Argument, p. 20.
[6] Exhibit B-1-1, p. 84, Table 37.
[7] Exhibit B-1-1, pp. 77, 78; Exhibit B-3, BCUC IR 42.4, 43.4.1, 44.2 and 47.2.
[8] Exhibit B-3, Attachment BCUC 1.46a, p. 4.
[9] Exhibit B-1-1, pp. 87–88 and PNG-West Final Argument, pp. 20-21
[10] Exhibit B-3, BCUC IR 43.4, PNG-West Final Argument, p. 22.

The issue for the Panel to consider is whether the approach taken by PNG-West to include certain projects as part of its RRAs is in accordance with the UCA and reasonable for capital expenditures or whether filing a CPCN for each capital project is required. The position taken by PNG-West is that a CPCN application is not required. It has stated that in each of these cases it has no intention of submitting an application for a CPCN. With reference to the Copper River and the RIPET projects, PNG-West states that it does not consider there to be a requirement to file for a new CPCN explaining that the UCA already authorizes it to construct, maintain and operate the system. For the geographic information system (GIS) PNG-West explains that it has filed a business case containing information and analysis similar to what would be covered under a CPCN application. PNG-West observes that if the BCUC required separate CPCNs for these projects it would entail reviewing information that has been provided in this proceeding and duplicate the information on the record. In its view this would be an inefficient use of the BCUC and intervener time.[11]

Section 45 of the UCA provides direction with respect to the issuance of CPCNs. Subsection 1 states that:

> Except as otherwise provided, after September 11, 1980, a person (public utility) must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction or operation.

Section 45 (2) addresses those instances where a utility has been operating a public utility plant or system on September 11, 1980. In this case a public utility is deemed to have received a CPCN providing authorization to operate the plant or system or to construct and operate extensions to the plant or system. However, this authorization is further subject to subsection (5) which states:

> If it appears to the commission that a public utility should, before constructing or operating an extension to a utility plant or system, apply for a separate certificate of public convenience and necessity, the commission may, not later than 30 days after construction of the extension has begun, order that subsection (2) does not apply in respect of the construction or operation of the extension.

This allows the BCUC some latitude to examine proposed projects which have begun but is tempered by the 30-day limitation. This has the effect of restricting the BCUC's ability to stop construction of an extension where a material amount of work has been completed and initiate a process to determine whether a CPCN allowing the project to proceed will be granted.

The provisions and limitations as outlined in Sections 45(1), 45(2) and 45(5) are based on the assumption that the BCUC has knowledge of or is at least aware that the extension of the plant or system is being planned. This is provided for in section 45(6) which states:

> A public utility must file with the commission at least once a year a statement in the form prescribed by the commission of the extensions to its facilities that it plans to construct.

This annual statement provides the BCUC with a listing of the capital projects being planned, the reasons they are being undertaken as well as the details related to them. If filed in advance of construction being initiated, the BCUC is then afforded an opportunity to provide oversight prior to the project being initiated and the time to determine whether a CPCN is appropriate. For many utilities it is standard practice to include this information as part of their Annual Report.

[11] Exhibit B-3, BCUC 42.2, 43.2 and 46.4.

The Panel notes that PNG-West did not file a statement outlining its plans for any of the three projects in question prior to filing its 2018-2019 RRA on November 30, 2017. Moreover, it did not outline its plans for the RIPET project until filing its Amended Application on February 28, 2018. With respect to the status of each of these projects, PNG-West reports the following:

- work began on the RIPET project in July 17, 2017;
- the Copper River project was to commence in January 2018; and
- the GIS project is in the detailed analysis and planning stage of its phase one implementation.[12]

The issue for the Panel to determine is how best to report capital expenditures and determine the need for CPCN applications prior to the initiation of construction.

BCUC determination

Given the size of these projects, the magnitude of capital expenditures in 2018 and the resultant impact on PNG-West's rate base, the Panel is of the view that some of the projects in question may have been more appropriately examined through a CPCN application rather than as part of an RRA. PNG-West's position is that neither the RIPET nor the Copper River projects require a CPCN. In PNG-West's view it has already been authorized by the UCA to construct, maintain and operate the system for Copper River. As for the RIPET project, PNG-West states that it primarily entails replacement and reinforcement of pipe that was installed pursuant to the CPCN for the PNG pipeline.[13] With respect to the GIS it takes no position as to whether a CPCN is required but notes that information and analysis similar to what would be covered if there had been a CPCN application had been included in the RRA.

With respect to the Copper River project, the Panel agrees with PNG-West that a CPCN is not a requirement as it falls under the maintenance and operation of an existing approved CPCN. However, the Panel disagrees with the PNG-West assessment of the RIPET project. In our view this project goes well beyond the operation of an existing pipeline deemed to have received a CPCN as outlined in section 45(2) and could be described instead as an expansion of the existing pipeline and the construction of a new additional pipeline. Given this interpretation under section 45(1) of the UCA a CPCN would be required. Similarly, the GIS project when considered along with the Asset Record Modernization (ARM) project is a significant project entailing the construction of a system, and therefore, requires a CPCN to be filed.

However, the Panel acknowledges there has been a body of evidence related to these capital projects presented in this RRA and notes there is some ambiguity with regard to the interpretation of the CPCN requirements of the UCA. Given these circumstances and, in the interests of regulatory efficiency, the Panel considers there to be a need for latitude in this instance. **Accordingly, the Panel has determined that it is appropriate to review all of these projects within the current PNG-West RRA process as requested by the Applicant.** Nonetheless, while acknowledging there may be some ambiguity regarding when a CPCN application is required, the Panel believes there is value in developing processes to avoid situations where the default position is to file for acceptance of capital projects such as these as part of an RRA.

As noted, section 45(6) of the UCA requires a utility to file at least once a year with the BCUC a statement of the extensions to its facilities it plans to construct. As further noted, PNG-West did not file a statement outlining its plans for any of the three projects which were in various stages of development prior to filing its 2018-2019 RRA on November 30, 2017. Moreover, it was silent on plans for the RIPET project until filing its Amended

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[12] Exhibit B-6, BCUC IR 90.1
[13] Exhibit B-3, BCUC 42.2 and 43.2.

Application on February 28, 2018. The timing of the RRA filing was such that the BCUC had no opportunity to review the projects and, in accordance with section 45(5), assess whether a CPCN was required in advance of the work being initiated. Had PNG-West complied with section 45(6) in a timely fashion the need for a CPCN for these projects could have been reviewed and adjudicated prior to significant work being undertaken. **Because of this, the Panel has determined that there is a need to develop a process to allow PNG-West's future capital expenditures to be considered in advance of construction and assess where a CPCN process would be in the public interest. Accordingly, the Panel orders PNG-West to file a proposal for a report to the BCUC, to be filed annually, which outlines its future construction of extensions and new facilities as well as any significant system modifications or additions that are planned.** PNG-West's submission is to be filed no more than 60 days following the Order accompanying these reasons 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**.**

2.2 Proposed rate deferral mechanism

PNG-West proposes to establish a rate deferral mechanism whereby the full impact of the combined rate changes for Test Years 2018 and 2019 are balanced over the two year period. This is accomplished by recording $1.45 million of the Test Year 2019 revenue deficiency in Test Year 2018 in a short-term interest bearing deferral account, to be fully amortized in 2019. This results in a forecast residential delivery rate decrease of 1.3 percent and 1.4 percent in 2018 and 2019, respectively, as compared to a rate decrease of 5.6 percent in 2018 and a rate increase in 2019 of 7.9 percent in the absence of the rate deferral mechanism. PNG-West submits that the rate deferral mechanism "is prudent and beneficial to customers as it provides rate stability by reducing rate volatility." [14]

Positions of the parties

BCOAPO *et al* raises a concern with PNG-West's proposed rate deferral mechanism submitting that "the proposed rate decreases will buy short term gain for long-term pain: higher rate increases." BCOAPO *et al.* explains that "this is based on the fact that PNG West's evidence is that 2019 rates at the 2017 level, or lower as per the proposal, result in a revenue deficiency on a standalone basis." This will result in a larger than otherwise rate increase in Test Year 2020 than would have been the case had the revenue deficiency for 2019 been recovered in that year. BCOAPO *et al*. also notes that, within the IR process, it suggested an alternative to PNG-West's proposal of small, equal rate increases of 0.924 percent or less in each of Test Years 2018 and 2019. Using a 0.924 percent rate increase in each of Test Years 2018 and 2019 would result in the same rates in Test Year 2019 as would be the case in the absence of PNG-West's proposed rate deferral mechanism. However, BCOAPO *et al.* does acknowledge that this would result in an over-collection by PNG-West of its revenue requirement and would require an interest-bearing deferral account to book the over collection from customers over the two year test period. While BCOAPO *et al.* states that it is not "unequivocally opposed to PNG West's rate proposals," it submits that the alternatives to PNG-West's proposed rate deferral mechanism presented by BCOAPO *et al.* merit PNG-West's consideration.[15]

[14] Exhibit B-1-1, pp. 7, 10.
[15] Exhibit B-5, BCOAPO IR 2.1-2.3; Exhibit B-8, BCOAPO IR 1.1-2.3; BCOAPO Final Argument, pp. 2–3.

PNG-West submits that the Test Year 2020 residential rates will be the same with or without the proposed rate deferral mechanism and its proposed rate deferral mechanism is effective and does not result in "over collection from its customers" over the two year test period. However, it does concede that the hypothetical rate increase for Test Year 2020 will be greater under the proposed rate deferral mechanism than if the mechanism were not applied, "primarily due to the margin requirement in [Test] Year 2020 under the rate deferral scenario due to the lower customer rates in Test Year 2019."

PNG-West states that it has considered BCOAPO's proposed alternative but notes that it would require two separate deferral accounts, which may be more confusing, and also delays the rate decreases proposed by PNG-West for Test Years 2018 and 2019 to Test Year 2020. In summary, PNG-West argues that its proposed rate deferral mechanism is "fair, effective and administratively efficient to implement" and "the impacts of PNG's proposed mechanism are limited to 2018 and 2019, the test period under review in this proceeding."[16]

BCUC determination

The Panel approves PNG-West's proposed rate deferral mechanism as outlined in its Application. The rate deferral mechanism as proposed, effectively balances the impact on rates over the two-year period smoothing out the large rate fluctuations that would have occurred if it were not employed. The Panel notes BCOAPO *et al's* concerns with the increase in 2020 rates but is not persuaded that BCOAPO *et al's* proposed alternative approach is an appropriate solution. We accept that BCOAPO *et al's* proposal would result in slightly lower rates in 2020 than would otherwise be the case but these would be at the expense of overcharging customers for the two prior years. This, in addition to delaying benefits to customers for two years as noted by PNG-West, would force the reconciliation of accounts into a future test period. The Panel notes that in addition to being less efficient administratively, carrying balances further forward would be less aligned with the principle of intergenerational equity.

3.0 Cost of service issues

3.1 Operating, maintenance, administrative and general expenses

PNG-West is requesting recovery of the following operating, maintenance and administrative and general (OMA) expenses for the 2018 and 2019 test period, subject to the adjustments identified by PNG-West in information requests and in argument:

Table 2: PNG-West OMA Expenses[17]

	Test Year 2018	**Test Year 2019**
Operating (net of transfers to capital)	$9,208,000	$9,473,000
Maintenance	$495,000	$505,000
Administrative and General (net of transfers to capital)	$7,795,000	$8,158,000
Total	$17,498,000	$18,136,000

[16] PNG Reply Argument, pp. 2 and 6–7.
[17] Exhibit B-1-1 pp. 32, 39 and 41.

The 2018 forecast OMA expenses are $195,000 or 1.13 percent higher than the 2017 forecast OMA expenses.[18] Of this increase, $172,000, is attributable to operating expenses and PNG submits that the primary drivers for the increase include:[19]

i. General inflationary pressures;

ii. Planned engineering projects including digital data mapping and the implementation of a geographical information system; and

iii. Forecast labour cost increases attributable to new positions in the areas of engineering and records management.

The 2019 forecast OMA expenses are $638,000 or 3.65 percent higher than the 2018 forecast amount. Of this increase $265,000 is attributable to operating expenses and $363,000 is attributable to administrative and general expenses. PNG-West submits that the increase in operating expenses is primarily due to inflation, increased labour costs to provide for the handover on anticipated retirements and an increase in vehicle cost allocation to operating expense due to lower planned capital expenditures in 2019.[20] The primary drivers of the increase in administrative and general expenses include:[21]

i. Increased labour costs reflecting forecast annual salary increases for its salaried non-bargaining unit employees and executives; and

ii. A decrease in transfers to capital in 2019 compared to 2018 consistent with the forecast decrease in capital expenditures in 2019 compared to 2018.

BCOAPO *et al.* did not raise any issues with the forecast OMA expenses in this proceeding.

BCUC determination

The Panel has reviewed the evidence on record in the proceeding and the reasons for the increase in OMA expenses in Test Years 2018 and 2019 and finds the OMA expenses requested for recovery in 2018 and 2019 to be reasonable, with the exception of the issues addressed in section 3.1.1. **Subject to the adjustments identified by PNG-West in information requests, in argument and the determinations on issues addressed in section 3.1.1, the Panel approves the 2018 and 2019 OMA expenses requested.**

3.1.1 Operating labour

PNG-West forecasts an increase in operating labour for Test Year 2018 of $224,000 or 3.6 percent over the 2017 forecast amount.[22] The primary causes of the increase in labour costs are the hiring of a new Records Clerk and a Project Engineer, in addition to inflationary increases.[23] PNG-West notes that a new Maintenance Coordinator position also contributes to the increase in the 2018 forecast for operating labour expenses as compared to the 2017 forecast.[24]

[18] Exhibit B-1-1, pp. 32, 39 and 41: $9,036,000 + $487,000 + $7,780,000 = $17,303,000.
[19] Exhibit B-1-1, p. 32.
[20] Exhibit B-1-1, p. 33.
[21] Exhibit B-1-1, pp. 41–42, 56.
[22] Exhibit B-1-1, Tab 1, p. 2.
[23] Exhibit B-1-1, p. 35; PNG Final Argument, para. 26(iii); Exhibit B-3, BCUC IR 9.6.
[24] Exhibit B-7, CONFIDENTIAL BCUC IR 58.6.

PNG-West submits that the new positions are required as it is critical it improves its personnel, processes and technology to keep up with more rigorous pipeline integrity standards and regulations.[25] PNG-West further submits that the new Records Clerk position is necessary to organize, file, scan and operate PNG-West's document management systems and the new engineer position is primarily to support capital activity.[26]

PNG-West expects the new Records Clerk and Project Engineer positions to commence in the third quarter of 2018, with the labour costs allocated to more than one operating expense account but has not indicated when the new Maintenance Coordinator position is expected to commence.[27] PNG-West provided the forecast labour costs of the new positions for the Test Period, which shows that the 2019 forecast labour costs are comparable to the 2018 forecast with marginal increases.[28] Therefore, it appears that the 2018 forecast labour costs have not been prorated to reflect the anticipated start date of the positions.

BCUC determination

The Panel has reviewed the evidence on record in the proceeding and accepts PNG West's explanation of why the new Records Clerk and Project Engineer positions are necessary. However, based on the evidence presented, the Panel finds that the forecast labour costs for the new Records Clerk and Project Engineer positions have not been prorated for 2018 to reflect the anticipated start date of each position. Further, the Panel is concerned with the lack of details provided for the new Maintenance Coordinator position and it is unclear in the evidence presented if the forecast labour costs for this position have been properly prorated for 2018. The Panel notes that information on the new Maintenance Coordinator was not provided in the Amended Application and only came to light in the second round of IR responses and considers it important that PNG-West provide more detailed information in future RRAs to allow for a more efficient review process. **PNG-West is directed to prorate the 2018 forecast labour costs for each of these new positions in its final regulatory schedules to be included in its compliance filing, as applicable. For Test Year 2018, the Panel approves the recovery of the forecasted salaries prorated for the anticipated start dates of each of these positions.**

3.2 AltaGas inter-affiliate charge

PNG-West reports that since AltaGas acquired PNG in December 2011, the parent company has incurred certain expenses to maintain its public reporting status that were formerly incurred by PNG. These expenses are currently recovered by an inter-affiliate charge to PNG-West. PNG-West states that in determining the AltaGas inter-affiliate charge for the current Application it has applied an inflationary increase of 2 percent for both 2018 and 2019 on the allowed consolidated recovery of $715,000 approved in the 2016-2017 RRA proceeding.[29] PNG-West further states that "to not allow for an inflation factor on PNG's historical costs of being a public company is punitive as the types of costs incurred are subject to inflationary increases from time-to-time."[30]

In response to Order G-131-16 for PNG-West's 2016-17 RRA, the company has conducted a review and analysis of the AltaGas inter-affiliate charges and the resultant report prepared by KPMG LLP has been appended to the Application. The report also contains a document stating the AltaGas corporate services cost allocation principles and a summary of the corporate service allocation model as well as a document outlining PNG West's estimate of the fair value of the corporate services received from AltaGas. On the basis of this report PNG-West

[25] Exhibit B-3, BCUC IR 9.1.
[26] Exhibit B-3, BCUC IR 9.2.1; B-6, BCUC IR 68.1.
[27] Exhibit B-3, BCUC IR 9.2; Exhibit B-6, BCUC IR 58.7.
[28] Exhibit B-3, BCUC IR 9.2; Exhibit B-7, CONFIDENTIAL BCUC IRs 58.6 & 58.8.
[29] Exhibit B-1-1, p. 44; BCUC Order G-131-16 with Reasons for Decision.
[30] Exhibit B-1-1, pp. 44 and 51–52.

submits the fair value of the corporate services received from AltaGas exceeds the charge that PNG-West is paying for the services.

PNG-West acknowledges that it is cognizant of the impact of increasing the recovery of the inter-affiliate charge and seeks only to recover the aforementioned inflation in addition to the 2017 approved amount of $715,000. It states that it ultimately expects to seek recovery of all costs related to maintaining its capital structure, providing access to capital and delivery of other corporate services that are allocated by its parent and reserves the right to reapply for a share of achieved synergies in future applications.[31]

BCUC determination

The Panel agrees with PNG West's request and approves for PNG-West to recover $730,000 of the Alta-Gas inter-affiliate charge in Test Year 2018 and $743,000 in Test Year 2019 on a consolidated basis, reflecting an inflationary increase of two percent for each of 2018 and 2019 over the 2017 approved amount of $715,000. The Panel notes that it has been a number of years since there was an increase in the amount of the approved affiliate charge and therefore, a two percent inflationary increase is warranted and reasonable. The Panel acknowledges that PNG-West has complied with Order G-131-16 and has filed a report authored by KPMG LLP outlining the analysis and review of AltaGas corporate inter-affiliate charges.

3.3 Other items

3.3.1 Code of conduct and transfer pricing policy

PNG's Code of Conduct (COC) and Transfer Pricing Policy (TPP) are dated November 2011, and were approved by BCUC Order G-130-12.[32] PNG-West states that these policies were prepared in consideration of the BCUC's Retail Market Downstream of the Utility Meter (RMDM) Guidelines and primarily to address matters regarding non-regulated business (NRB) activities and govern the provision of utility resources and services to PNG's nonregulated businesses and affiliates. The applicability of these policies in relation to the RIPET project, where Alta Gas is one of the joint venture partners and also an affiliate of PNG, was raised during the IR process. PNG-West states that:

> …[i]n the context of the RIPET Project, AltaGas, one of the joint venture partners on the project, would be considered an affiliate of PNG. And while the COC and TPP are structured to address NRBs and RMDM matters, the spirit of these policies has guided PNG's conduct with AltaGas as it pertains to the RIPET Project.

PNG-West states that it recognizes, "an update to the COC and TPP are in order, particularly as they pertain to activities and transactions with related corporate entities" and it will undertake to update the COC and TPP and file them with the BCUC for approval in 2018.[33]

BCUC determination

The Panel notes that the acquisition of the issued and outstanding common shares of PNG by AltaGas was approved by the BCUC in 2011 by Order G-192-11 and the COC and TPP are dated November 2011. Accordingly, the Panel is in agreement that an update to the COC and TPP is required, in particular to address activities and

[31] Exhibit B-1-1, pp. 51–52; Final Argument, p. 12.
[32] Exhibit B-6, BCUC IR 83.1.
[33] Ibid

transactions with related corporate entities including Alta-Gas. **PNG-West is directed to file an updated COC and TPP with the BCUC for approval by December 31, 2018.**

4.0 Capital Expenditures

As outlined in Section 2.1, PNG-West has filed a listing of capital expenditures for 2018 totalling $15.218 million which is much higher than recent historical levels. In 2019 the filed capital expenditures total $4.582 million which is more in keeping with recent historical levels. Capital expenditures are separated into two categories; recurring, or those that are needed on an ongoing basis and non-recurring, those that are related to specific projects which the company plans to undertake. Recurring projects involve items like new services, meter and regulator purchases and investigative dig cut-outs; budgeted costs for these total $2.060 million in 2018 and $1.665 million in 2019. Non-recurring projects include individual projects of varying sizes and have been budgeted at $13.158 million in 2018 and $2.916 million in 2019.[34]

Recurring projects

Based on PNG-West's Application, budgeted amounts for recurring projects in this Application are significantly lower than the previous two years. As noted in Section 4.5, there was a significant level of underspending on recurring projects over the most recent test period. A review of the information provided by PNG-West indicates that this was primarily due to lower requirements for new services, less need for investigative dig cut-outs and, in the case of Unspecified Mainline Repairs, a reallocation of funds to other projects. The total of $3.725 million budgeted for 2018 and 2019 for recurring projects is reflective of recent historical experience and lower anticipated needs going forward.[35]

Non-recurring projects

As discussed in Section 2.1, there are two large projects planned for 2018 which account for a significant portion of the 2018 requirements for capital. These include the Copper River MP 250 repair, and the RIPET project. These will each be examined in detail in subsequent sections, along with the GIS project. In addition, as outlined in PNG-West's Application, there are a number of other non-recurring projects which make up the balance of capital requirements. Most significant of these are compressor station upgrades ($1.772 million) which are needed to keep the facilities in safe operating condition, line heater replacements ($0.518 million) to replace units no longer fit for service and transmission mainline repairs and assessments ($0.429 million).[36]
Non-recurring projects for 2019 involve more modest expenditures than those in 2018. Most significant of these are structure improvements ($0.603 million), primarily for replacement of an end of life building in Terrace, transmission mainline repairs and assessments ($0.566 million) for the post assessment phase two of the Salvas to Galloway pipeline remediation and compressor upgrades ($0.387 million) for a series of projects that must proceed to keep the facilities in safe condition.[37]

BCUC determination

The Panel notes that PNG-West has reacted to lower levels of recurring capital spending by reducing budgeted requirements significantly from the previous test period. As a result, requirements for the current test period are actually lower than actual expenditures in the previous test period. The Panel finds this a reasonable

[34] Exhibit B-1-1, p.86 and p. 92.
[35] Exhibit B-1-1, pp. 85–94.
[36] Exhibit B-1-1, p. 85.
[37] Exhibit B-1-1, p. 92.

approach that is likely to result in the elimination or reduction in under expenditures that have occurred with recurring capital in recent years.

The most significant projects are discussed individually in Sections 4.1 to 4.3 which follow. As for the balance of non-recurring projects, the Panel finds that PNG-West has provided evidence to justify the need for these projects, many of which involve replacement of aged facilities and replacement of equipment to ensure safe and reliable operations are maintained.

Accordingly, the Panel accepts PNG-West's filing of capital expenditures, subject to adjustments identified in the IR process and any further directives concerning specific projects made within these Reasons for Decision. **The incorporation of the capital expenditures into rates is approved upon completion of the projects, and subject to any prudency review of expenditures that may arise.**

4.1 Copper Mountain MP 250 repair

PNG-West requests approval of capital expenditures for the Copper River MP 250 Repair project. In October 2017 PNG-West experienced a major washout on the Zymoetz (Copper) River, exposing a main, high pressure transmission pipeline.[38] PNG-West describes the need for the project as follows: "[t]he permanent repair to Copper River MP 250 is an integral project necessary for the safety, reliability and integrity of the transmission system. Importantly, PNG-West is in a situation where the permanent repair is urgent or a major rupture and outage could occur without immediate action." PNG-West confirms that the project is a "like for like" replacement with the previous pipeline in terms of capacity and size with no appreciable difference in pipeline length.[39]

The project is designed to carry out a permanent repair and relocation of 700 meters of pipeline and involves construction in an environmentally sensitive area with a difficult to access location. PNG-West has outlined a number of alternative solutions it has considered and evaluated each based on construction costs, the risk/probability of a repeat occurrence, maintenance costs, non-financial factors and from an overall life cycle cost perspective. PNG-West states that based on this it identified relocation of the pipeline to a new full-bench right-of-way located above the 200-year flood plain as most favourable. This solution has the lowest cost of repair, the lowest risk of repeat occurrence, low maintenance cost considerations and the least risk or impact when non-financial factors such as permitting and stakeholder relations are considered.[40]

The project cost estimates are based on a Class 4 estimate. In the Amended Application and Final Argument, PNG-West states that the total estimated capital cost for the project is $5,785,000, with $80,000 in capital spending having been incurred in 2017. PNG-West states that the detailed design has commenced which will result in a Class 3 estimate and a detailed construction schedule being developed. In addition, it will have better certainty with costs once tendering is completed in August, 2018.[41] In its response to IRs, PNG-West states that the total project costs are expected to be in line with the budgetary control cost estimate of $5,630,000 and all costs are to be incurred in 2018 except for $104,441 incurred in 2017 for the permanent repair.[42]

PNG-West notes there is the potential for a cost sharing arrangement with BC Ministry of Forests, Lands and Natural Resource Operations (FLNRO) and other stakeholders for the building of the pipeline access and armouring which will act as a roadway. These negotiations are still ongoing. In addition, PNG-West notes there

[38] Exhibit B-1-1, pp. 87–88.
[39] Exhibit B-3, BCUC IR 42.2, 42.3.
[40] Exhibit B-1-1, p. 88; Exhibit B-3, BCUC 42.1, 42.1.1.
[41] Exhibit B-1-1, p. 88; Exhibit B-3, BCUC 42.4.
[42] Exhibit B-3, BCUC IR 42.5.

may be a case for an insurance claim and is pursuing this with its insurance company.[43] The Company remains confident that it will be able to defray some of the costs by recovering funds from the insurer, FLNRO or other stakeholders.

PNG-West states that the project was commenced in January 2018 with construction expected to be completed by October 2018 and site demobilization in November 2018 and is on track with the milestone schedule. With reference to the project schedule PNG-West further explains:

> …both permitting and overall project delivery schedule are considerable risks to project delivery in 2018. Should the project show signs of significant schedule slip such that permitting and contract related milestones will not be met, a contingency plan will be executed to further armor the temporary bypass pipeline in order to protect against fall water levels and river velocities. This will push project completion into 2019 and result in a projected increase in armoring costs of approximately $1,000,000.[44]

In response to IRs PNG-West further states that the primary financial risk associated with the project will be cost impacts associated with weather such as elevated water levels during fall precipitation which pose a threat to washing out additional existing pipeline sections both upstream and downstream of the existing washout. It has identified such risk locations based on river activity and mitigated this risk by incorporating armouring and repairs into the project schedule. PNG-West also points out that there is a financial risk related to impeded access due to snow accumulation, which could shift the project schedule into early winter. This has been mitigated by applying additional resources upfront to identify an achievable project schedule and working on an accelerated permit and design process.[45]

BCUC determination

In the Panel's view, PNG-West has provided sufficient evidence to demonstrate the need for the project and has conducted an appropriate assessment of the project alternatives. **Accordingly, the Panel accepts PNG-West's filing of capital expenditures for the Copper River MP 250 Repair project. The incorporation of the project costs into rates is approved upon completion of the project, and subject to any prudency review of expenditures that may arise.**

While satisfied that PNG-West has taken steps to mitigate issues related to project scheduling, the Panel notes that the project could be subject to delays and financial risk due to weather, elevated water levels, permitting or contract related issues. Further, the Panel notes that in its Amended Application and Final Argument PNG-West estimates the capital cost for the project at $5,785,000, with $80,000 in capital spending having been incurred in 2017. However, contrary to this, in its response to IRs PNG-West states that the total project costs are expected to be in line with the budgetary control cost estimate of $5,630,000 and all costs are to be incurred in 2018 except for $104,441 incurred in 2017 for the permanent repair. **Therefore, the Panel directs PNG-West to submit a compliance filing within 30 days of the issuance of the order accompanying these reasons for decision, to include project status, schedule, costs and any budget variances, any difficulties that the project has encountered and any material changes to the identified risks. In addition, the compliance filing is to include an explanation for the discrepancy in the total project costs and 2017 costs incurred to date between the Amended Application/Final Argument and IR responses. The Panel also direct PNG-West to file the Class 3 estimate as soon as reasonably practicable but no later than 30 days within the issuance of the order accompanying these reasons for decision.**

[43] Exhibit B-1-1, p. 88
[44] Exhibit B-3, BCUC IR 42.4.
[45] Exhibit B-3, BCUC IR 42; Exhibit B-6, BCUC IR 80.8.2.

4.2 Geographical Information System and Asset Record Modernization projects

The Geographical Information System (GIS) is a project designed to provide access to accurate, trusted and complete information on the PNG companies' key assets anywhere within PNG's service territory. When completed, it will provide a repository of spatial information on assets with cross-references to non-spatial information on other enterprise IT systems. PNG-West states that its management of geospatial asset and topographical data is becoming untenable and GIS technology will provide opportunities to improve process efficiency and consistency between geographic locations, integrate key business systems, improve communication and streamline workflows. PNG-West submits that because of the lack of a GIS system, it is at risk of being out of compliance with codes, standards, and regulations. Moreover, a delay in adopting GIS technology increases its exposure to risks related to the provision of safe and reliable delivery of natural gas.[46]

The ARM project, while supported by the GIS, is a completely autonomous initiative that will digitize all pipeline and associated facility design and construction records. PNG-West explains that, "[u]pdates to the CSA Z662 standard, a directive from the BC Oil and Gas Commission and Technical Safety BC, and amended bylaws of the Association of Professional Engineers and Geoscientists of BC have all required improvements to records management by operators of gas pipeline systems." PNG-West states that whilst the successful completion of the GIS implementation is not critical to the success of the ARM project, GIS will enhance the effectiveness of its asset records management.[47]

In addition, PNG-West has identified two further projects: Digital Data Mapping (DDM) and Computerized Maintenance Management System (CMMS) that will collectively address the state of its utility asset information.[48] The DDM project will identify geological and hydrological hazards and the CMMS is a stand-alone project that will replace PNG's current asset management system. The timing of the DDM and GIS Implementation do not need to be coordinated for either project to be successful, however the full benefits of the DDM project cannot occur until both projects are complete.[49] PNG-West notes that the CMMS project's implementation is being completed independent of the GIS Implementation but integration of the two systems is contemplated for the future.[50]

The GIS and ARM projects are to be delivered across both the PNG-West and PNG(NE) service areas and the consolidated capital expenditures for the projects are estimated to be $2,394,100 and $1,472,740 respectively.[51]

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[46] Exhibit B-3, Attachment 1.46a, pp. 1, 18; Exhibit B-3, BCUC IR 46.2, 46.5; PNG(NE) RRA Reply Argument, p. 8.
[47] Exhibit B-10, Panel IR 1.1; Exhibit B-3, Attachment 1.46a, p. 8; Exhibit B-10, Panel IR 1.1.
[48] Exhibit B-3, Attachment 1.46a, p. 8; Exhibit B-10, Panel IR 1.1
[49] Exhibit B-10, Panel IR 1.1.
[50] Exhibit B-10, Panel IR 1.1.
[51] PNG-West Final Argument, p. 23; Exhibit B-3, Attachment BCUC 1.46a, p. 4; Exhibit B-3, BCUC IR 47.2; Exhibit B-3, Attachment 1.46a, p. 4.

A breakdown of the consolidated GIS project costs by year and per division are included below:

Table 3: Consolidated GIS Project Costs[52]

Division	Allocator	2018	2019	2020	TOTAL
PNG-West	62.34%	$ 441,000	$ 671,000	$ 399,500	$ 1,511,500
PNG(NE) - FSJ/DC	36.40%	$ 242,000	$ 377,000	$ 233,300	$ 852,300
PNG(NE) - TR	1.26%	$ 8,700	$ 13,500	$ 8,100	$ 30,300
Total	**100.00%**	**$ 691,700**	**$ 1,061,500**	**$ 640,900**	**$ 2,394,100**

A breakdown of the consolidated project costs for the ARM project by year and per division are included below:

Table 4: Asset Record Modernization Total Capital Costs per year and per division[53]

Asset Records Modernization Project Capital Costs	2018	2019	2020	2021	2022	Total
PNG West	271,000	292,000	198,787	149,090	149,090	1,059,967
PNG(NE) FSJ/DC	15,200	-	84,484	126,727	126,727	353,137
PNG(NE) TR	-	-	14,909	22,364	22,364	59,636
	286,200	292,000	298,180	298,180	298,180	1,472,740

PNG-West states that it has not estimated any specific financial benefit(s) associated with the GIS project. However, its business case includes a number of case studies that detail the benefits realized by other GIS implementers. PNG(NE) further submits that without a GIS to manage its spatial data, it "would have to implement more labour-intensive processes, and therefore greater costs."[54]

Positions of the parties

PNG-West states that it needs to improve its ability to make decisions related to the management of its assets in order to optimize asset maintenance, improve safety and enhance the reliability of service, create opportunities for efficiency and allow compliance with regulatory requirements. Each of the four projects addresses an important aspect of its efforts to modernize the management of its assets and the integration and alignment of each of these projects provides additional benefits.[55]

BCOAPO *et al.* states that although it does not challenge that the GIS and ARM projects and may have increased benefits related to streamlining processes, improving communications and asset data access, it questions

[52] Exhibit B-3, Attachment BCUC 1.46a, p. 4; Exhibit B-3, Attachment 1.46a, p. 4.
[53] PNG(NE), Exhibit B-9, BCUC IR 83.1.1.
[54] Exhibit B-6, BCUC IR 86.1.1.
[55] Exhibit B-10, Panel IR 1.1.

whether they should be wholly or even partially ratepayer-funded when this project involves no quantifiable ratepayer financial impacts.[56]

In reply, PNG(NE) asserts that it has never taken the position that the GIS project will not result in quantifiable ratepayer financial benefits, rather it has elected not to attempt to quantify those benefits. PNG(NE) further states that it considers the GIS and ARM projects necessary from the perspective of compliance and risk and a GIS will avoid additional costs associated with compliance and future regulations. PNG(NE) reiterates the need to modernize its asset records and states that the costs should be borne by the ratepayers.[57]

BCUC determination

The issue for the Panel is whether there is a need for the GIS and ARM projects and if so, are there financial benefits to be derived from their implementation.

PNG-West has provided evidence its management of geospatial asset and topographical data is becoming untenable and failure to address these issues will place the PNG companies at risk of non-compliance with various codes, standards and regulations. Moreover, if these projects are delayed there is increased risk related to the safe and reliable delivery of gas to its customers. Given these circumstances the Panel is persuaded there is a need for the projects and moving forward in a timely manner will reduce risk to PNG's customers. The Panel notes that on these points there is no challenge from BCOAPO *et al*. In addition, the Panel notes that the projects offer opportunities for improving operations including processes and efficiencies, geographic consistency, business systems integrations, communication and workflows as well as the additional benefits that could be realized in the future through coordination with the DDM and CCMS projects. Further, while not quantifying the financial benefits related to these improvements, PNG-West acknowledges that it has not denied that there will be financial benefits related to them. **Therefore, the Panel accepts PNG-West's filing of 2018 and 2019 capital expenditures of $1,112,000 and $563,000 for the GIS and ARM projects, respectively. The incorporation of the project costs into rates is approved upon completion of the projects, and subject to any prudency review of expenditures that may arise.**

While the Panel has accepted capital expenditures for this project, we remain concerned with the lack of work done by PNG-West to quantify the anticipated financial benefits; a point also alluded to by BCOAPO *et al*. PNG-West has stated that it does not deny that financial benefits will exist but has yet to attempt to quantify them. In the Panel's view this needs to be addressed and any cost savings appropriately applied to future revenue requirements once the projects have been implemented. **Accordingly, the Panel directs PNG-West to file a report in its next RRA on the GIS and ARM projects and related projects outlining detailed project benefits and any anticipated cost savings to be achieved.**

4.3 RIPET project

PNG-West requests approval of capital expenditures in 2018 for the Ridley Island Propane Export Terminal (RIPET) project. In 2017, PNG received a request from Ridley Island LPG Export Limited Partnership (RILE LP), to provide high pressure gas service to the RIPET facility near Prince Rupert. RILE LP is a joint venture between AltaGas LPG Limited Partnership, a wholly-owned subsidiary of AltaGas, and Vopak Development Canada Inc., a wholly owned subsidiary of Koninklijke Vopak N.V. (Vopak). AltaGas has a 70 percent interest and Vokap has a 30 percent interest.[58]

[56] PNG(NE) RRA, BCOAPO Final Argument, pp. 8–9.
[57] PNG(NE) RRA, PNG(NE) Reply Argument, p. 9.
[58] PNG Final Argument, p. 21.

With respect to the justification and need for the project, PNG-West states:

> Ridley Island is within PNG's service area, with PNG having an existing integrated system of high pressure and low pressure distribution main and service pipelines providing gas to a number of industrial customers on the island. Given this, PNG had a responsibility to find a service solution for RIPET once a formal request for service was made. The project provides direct benefits to PNG's existing customers with additional firm contract demand. It will be underpinned with a long-term contract and the project meets the requirements under the MX test.[59]

In order to provide high-pressure fuel gas service at the requested custody transfer point, PNG-West's existing 114mm high pressure steel main will be amended to allow for the tie-in of the service extension to the customer's facility. Approximately 2.4 kilometers of new 114mm steel pipeline will be required, along with a new pressure regulating and metering station.[60] The project has an in-service date of October 2018[61] and the total Class 4 project cost estimate is $4,482,500, of which $126,000 was spent in 2017.[62]

PNG and RILE LP have finalized negotiations of an Industrial Gas Sales Agreement (IGSA), under which RILE LP will pay demand charges based on a minimum monthly take or pay volume at PNG-West's Rate Schedule (RS) 4 Industrial sales rate. The primary term of the IGSA is 15 years with a clause to cap PNG's capital investment on this project at $4.5 million such that if the actual cost is higher, PNG will receive a Contribution in Aid of Construction (CIAC) from RILE LP.[63] PNG-West states that, under the terms of the IGSA, all capital and operating costs will be recovered and there will be positive rate impacts to other customers.[64] PNG-West filed evidence related to the IGSA in confidence in Exhibits B-3-1, B-9 and B-11. PNG also entered into a Backstop Agreement with RILE LP for the RIPET project to safeguard its existing customers from risk during the construction phase of the project. Evidence related to the Backstop Agreement was filed in confidence in Exhibits B-4, B-7 and B-11.[65]

BCOAPO *et al.* did not raise any issues with respect to the RIPET project. The Panel has however identified several issues related to the RIPET project, which are addressed in the sections that follow.

Stranded Assets

PNG-West proposes to use the standard depreciation rate of 1.41 percent applicable to its transmission pipelines for the RIPET project assets, which would result in an undepreciated balance of the assets of $3.4 million at the end of the 15 year term of the IGSA. In the event the assets are no longer used and useful at the end of the 15 years, PNG-West expects they would be deactivated and retired for regulatory accounting purposes. The undepreciated balance of the assets plus minimal costs required for deactivation would be recorded in the plant gains/losses deferral account and amortized over five years. PNG-West estimates that the write-off of the undepreciated assets would result in an incremental revenue deficiency of $970,000 in Year 16 and an approximate 2.9 percent delivery rate increase for residential customers. PNG-West states that it "is confident that the RIPET Project assets will continue to be used and useful at the end of the 15-year term as the Export Terminal is expected to continue operations." [66]

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[59] Exhibit B-3, BCUC IR 43.3
[60] PNG Final Argument, p. 21.
[61] Exhibit B-1-1, p. 88.
[62] Exhibit B-3, BCUC IR 43.4.
[63] PNG Final Argument, p. 22; Exhibit B-3, BCUC IR 44.3.1 and 44.6.
[64] PNG Final Argument, p. 22.
[65] Exhibit B-1-1, p. 89.
[66] Exhibit B-6, BCUC IR 85.2.2-85.3.1.

PNG-West provides a table with the expected annual revenue requirement impact of the RIPET project assuming a 6.6 percent depreciation rate, which matches the 15 year term of the IGSA. Using this depreciation rate, the net present value (NPV) of the 15 year revenue requirement is a net revenue sufficiency of $237,000.[67]

Security against RILE LP's obligations under the IGSA

The IGSA includes several clauses related to security against RILE LP's obligations under the IGSA. First, Section 8.2 requires RILE LP to pay a termination payment to PNG if the agreement is terminated under Section 8.1(b) due to "Buyer Event of Default"[68] Section 8.1 of the IGSA provides for early termination of the agreement only in accordance with the following:

(a) if both Parties agree in writing to such early termination; or

(b) by a Party on notice to the other Party if there is an event of default by the other Party.

[redacted]

Under Section 14.1 PNG may demand performance assurance, in the form of either a letter of credit or guarantee, if there are reasonable grounds for insecurity regarding the payment, performance or enforceability of any obligation of RILE LP under the IGSA.[70] [redacted]

[redacted]

BCUC Determination

PNG-West states that it had a responsibility to find a service solution for RIPET once a formal service request had been made. The Panel agrees that is a key consideration in determining there is a need for the project. Equally important, in the Panel's view, is that this is a request from a new customer and the provision of this service solution needs to be accomplished without forcing existing and future new customers to be burdened with undue risk. Put more simply, the costs of satisfying the customer need must be offset by the benefits to the ratepayer.

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[67] Exhibit B-10, Panel IR 2.1 and 2.1.1.
[68] Exhibit B-10-1, IGSA, Sections 8.1 and 8.2.
[69] Exhibit B-9, Confidential BCUC IR 10.1.
[70] Exhibit B-10-1, IGSA, Definitions and Section 14.1.
[71] Exhibit B11, Confidential Panel IR 1.10.
[72] Exhibit B-9, Confidential BCUC IR 7.2.
[73] Exhibit B-11, Confidential Panel IR 1.7.
[74] Exhibit B-9, Confidential BCUC IR 10.1.1.

In that regard, PNG-West has conceded that if the project were to be suspended at the end of the 15 year IGSA term, the remaining assets would be stranded with an undepreciated balance of $3.4 million remaining.

It is the Panel's understanding that if the IGSA were to be terminated after the initial 15-year primary term, existing ratepayers would nonetheless have received benefit. This is due to the project having a NPV net revenue sufficiency of [redacted] over 20 years, including the write-off of the undepreciated assets in years 16-20[75]. In that sense, existing customers are not at risk beyond the 15 year term of the IGSA. However, they would face rate increases following termination of this agreement as the asset would no longer be used and useful possibly requiring it to be fully depreciated over the next five-year period. For those customers that took service at a date following completion of the project there would be a level of risk. Depending upon when they took service they could potentially be required to pay in rates for an asset where they derived only limited benefit or in extreme cases, no benefit at all. On the other hand, if the agreement to provide service to RIPET continued beyond 15 years all existing and likely almost all future new customers would stand to gain from this project. Moreover, while there is no certainty that the agreement will continue beyond the 15 year primary term there is equally no certainty that it will not continue beyond this period thereby reducing the residual depreciation amounts and providing benefits to both existing and future new customers. Given these facts the Panel finds on balance that the potential benefits to existing and future ratepayers is likely to be greater than the risks ratepayers will be required to undertake. **Accordingly, the Panel is satisfied that the need for the project is justifiable and accepts PNG-West's filing of capital expenditures of $4,482,500 for the RIPET project. The incorporation of the project costs into rates is approved upon completion of the project, and subject to any prudency matters review of expenditures that may arise.**

While the Panel is satisfied that the need for the project has been demonstrated, we have concerns regarding the [redacted] and the terms surrounding the termination payment. [redacted]

With respect to the termination payment, the terms of the IGSA provide for this payment if the agreement is terminated due to "Buyer Event or Default"; however, the agreement may also be terminated "if both parties agree in writing to such early termination." [redacted]

In summary, [redacted] and the termination payment is not contractually required in all instances of early termination. Taking this into consideration, the Panel is strongly of the view that it would not be appropriate for the ratepayer to be required to bear any costs incurred in the event of early termination and/or the inability of RILE LP to meet its obligations under the terms of the IGSA. In the absence of these provisions, the Panel recommends that any future BCUC panel take this into account if and when difficulties arise from early termination or a failure to meet obligations under the IGSA.

4.4 EMAT ILI Tool Run and compressor small engine spare

PNG-West requests approval of two new rate base deferral accounts for two sets of costs. The first deferral account is to record the cost of the Electro-magnetic Acoustic Transducer (EMAT) In-line Inspection (ILI) tool

[75] Exhibit B-9, Confidential BCUC IR 8.8.1.

runs, forecast to be $1.2 million in 2018, to be amortized beginning with Test Year 2018 over 10 years, which is the anticipated period for the next in-line inspection. PNG-West also asks that this deferral account treatment be accorded to future EMAT ILI tool run costs on a go-forward basis.[76] The EMAT ILI tool run costs are incurred to detect cracks in pipes which could result in gas leaks if not repaired. These costs relate to inspection and maintenance activities to continue servicing the contracts to supply gas to customers.

The second deferral account is to record overhauled compressor engine spare costs, estimated to be $565 thousand in 2019, with amortization to begin over a minimum period of 5 years (based on a life cycle expectancy of five years) once the asset is put into service. These costs relate to overhauling one compressor engine out of six available compressor engines which have not been overhauled to ensure that a strategic spare unit is always available from storage and turned over occasionally so that it is ready to be used when needed or in the event of a major failure of an existing compressor engine.[77]

Proper Regulatory Accounting Treatment for Capital Expenditures

The issue for the Panel is the proper accounting and regulatory treatment of these costs and specifically whether they should be capitalized to plant or put in new rate base deferral accounts as PNG-West proposes.

PNG-West states that US Generally Accepted Accounting Principles (US GAAP) considers both options to be acceptable. However, PNG-West submits that including the costs in deferral accounts would more fairly allocate these costs between current and future ratepayers as they are effectively recorded and amortized on a net of tax basis. In contrast, capitalizing these costs as an addition to plant would result in timing differences impacting the current income taxes and thereby benefiting the current year ratepayers over ratepayers in future years.[78]

The resulting impact on residential delivery rates in the two year revenue requirement period for the two options (capitalization to plant versus deferral account) is summarized in the table below:

Table 5: Impact on Residential Delivery Rates[79]

	2018	2019
EMAT ILI Tool Run Costs Capitalized to Plant	-1.2%	0.8%
Compressor Engine Spare Capitalized to Plant	-0.6%	0.6%
EMAT ILI Tool Run Costs Deferred	0.1%	0.6%
Compressor Engine Spare Costs Deferred	0.1%	0.4%

For the EMAT ILI tool run costs, the NPV revenue requirement difference between putting them in a deferral account and capitalizing to plant is $36 thousand. For the overhauled compressor engine spare costs, the NPV revenue requirement difference is $10 thousand. In each case, the difference is mainly due to the significant tax

[76] Exhibit B-1-1, s. 2.9, p. 64 and s.3.4.1, p. 134.
[77] Exhibit B-1-1, s. 2.9, p. 65.
[78] Exhibit B-1-1, s. 2.9, pp. 64–65.
[79] Exhibit B-3, BCUC IR 30.0-32.0; Exhibit B-6, 75.0-76.5.

credit attributed to the cost of service in Year 1 when capitalizing to plant compared to putting the costs in deferral accounts. Over the proposed amortization periods, the NPV impact of the two accounting treatment options results in $46 thousand of additional ratepayer costs when put into deferral accounts rather than to plant.

Relevant to the determination of this issue is the BCUC's decision in the 2016-17 RRA proceeding, wherein the BCUC denied PNG-West's request to record the EMAT ILI tool costs of $487 thousand in a new rate base deferral account and directed PNG-West to capitalize the costs in accordance with US GAAP.[80] In accordance with that decision, PNG-West recorded $487 thousand of capital expenditures in plant to BCUC Account 469 in 2016. PNG-West points out, however, that it neglected to highlight to the panel at that time that the EMAT ILI tool run costs are fully deductible for tax purposes in the year incurred. Capitalization of these costs to plant would result in timing differences impacting current income taxes to the benefit of current year ratepayers over ratepayers in future years.

PNG-West submits it was that oversight which led that panel to conclude at page 18 of its Reasons for Decision as follows:

> …given PNG's statements that US GAAP allows for these cost 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 costs as operational expenses would result in large and volatile rate impacts.

Relevant US GAAP Provisions

In response to BCUC IRs, PNG-West points out that US GAAP ASU 2014-09, Section 340-40-25-8 allows four types of costs to be expensed and that the EMAT ILI costs match three of those four types:

a) *Costs of wasted materials, labor, or other resources to fulfill the contract that were not reflected in the price of the contract* – EMAT ILI costs include costs of resources not reflected on the contract and current gas bills of customers.

b) *Costs* that *relate to satisfied performance obligations (or partially satisfied performance obligations) in the contract (i.e., costs that relate to past performance)* – EMAT ILI costs, being maintenance in nature and resulting from past supply of gas, relate to satisfied performance obligations. They also relate to partially satisfied performance obligations as they will assist in the obligation to continuously supply gas.

c) *Costs for which an entity cannot distinguish whether the cost relate to unsatisfied, satisfied or partially satisfied performance obligations* - EMAT ILI costs relate to all three types of obligations since they cannot be specifically broken down in terms of past, ongoing and future gas supply service obligations.

US GAAP also allow the alternative treatment of costs to be capitalized, with BCUC approval, in Section ASC 980-340-25-1:

> An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:
>
> a) It is probable that future revenue in an amount at least equal to the capitalized cost will result from the inclusion of that cost in allowable costs for rate-making purposes.

[80] Exhibit B-1-1, p. 64.

b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.[81]

Although this section does not specifically prescribe how an asset capitalized thereunder should be categorized, PNG-West points out that this provision is a subsection of ASC 908-360 titled, "Property, Plant, and Equipment" which leads PNG-West to conclude that amounts allowed to be capitalized thereunder can be capitalized as plant.[82]

BCUC determination

In analyzing the relevant US GAAP provisions, PNG-West appears to have the option of either capitalizing the EMAT ILI tool run costs to plant or expensing them. As for the overhauled compressor engine spare costs, PNG-West submits that the same analysis ought to apply to those costs. However, rather than capitalizing these two sets of capital costs to plant or expensing them, PNG-West proposes a deferral account treatment for regulatory accounting purposes. PNG-West submits that doing so would allow the costs to be expensed for tax purposes in the year incurred but provide a more fair cost allocation as between current and future ratepayers. PNG-West concedes, however, that there are no additional benefits, other than the tax implications, to ratepayers whether the costs are recorded in a deferral account or capitalized to plant.[83]

Based on the wording of the specific sections of US GAAP, the Panel agrees with PNG-West's interpretation that both accounting treatment methods are permitted. The Panel also agrees that an apparent inequity arises from the 1.8 percent decrease in rates for 2018 ratepayers relative to an 1.4 percent increase in rates for 2019 ratepayers if the expenses were capitalized to plant, favoring 2018 ratepayers at the expense of 2019 ratepayers, as a result of the fact that the two sets of costs would be expensed for tax purposes in the year they are incurred. Balanced against that, though, is the fact that choosing to put the costs into deferral accounts rather than capitalizing those costs to plant actually increases the NPV revenue requirement, albeit by a small amount ($46 thousand), for ratepayers over the lifespan of the assets.

On balance, the Panel agrees with the decision of the previous panel in the 2016-17 Revenue Requirements proceeding. Wherever there is an available option to capitalize costs to plant rather than putting them into deferral accounts (as is the case here), the former is preferred over the latter since capitalization has the benefit of "providing the same relief against lumpy and volatile expenses."

The Panel finds that there is no logical reason to distinguish between the nature of the two sets of capital costs in question from a US GAAP basis. If capitalization to plant is appropriate for one set of costs, it should be equally appropriate for the other.

Based on the evidence before it, the Panel is not persuaded that deferral account treatment is appropriate for either of these two sets of capital costs. In short, the Panel finds that the most appropriate regulatory accounting treatment for the two sets of capital expenditures in question is to capitalize those costs to plant. **Accordingly, the Panel directs that PNG-West capitalize the $1.2 million in 2018 EMAT ILI tool run costs to BCUC Account 469, in accordance with US GAAP and depreciate over a period of 10 years. Similar treatment is to be accorded to future costs associated with the EMAT ILI tool run. Similarly, the Panel directs PNG-West to**

[81] Exhibit B-3, BCUC IR 30.1.
[82] Exhibit B-6, BCUC IR 75.2.
[83] Exhibit B-3, BCUC IR 31.1.1.1 and 34.3.1.

capitalize the $565,000 in overhauled compressor engine spare costs to plant for Test Year 2019 as those expenditures are incurred and depreciate over a period of 5 years once those assets are placed into service. PNG is directed to provide the plant account name applicable to the compressor engine overhaul costs in its compliance filing made pursuant to directive 20 of the order accompanying these reasons.

4.5 Capital expense variance reports

PNG-West reports that in the BCUC decision in the 2012 RRA proceeding, it was directed to provide more comprehensive capital addition expenditure reporting to improve transparency on a project-by-project and year-by-year basis.[84] Specifically, on a go-forward basis, PNG-West was directed to provide more detailed budget variance analysis in the context of its capital additions forecasting and to provide a schedule showing forecast plant additions compared to actual capital additions with explanatory information on all material differences. In accordance with this directive, PNG-West has, within its Application, provided a listing of capital expenditures and a table listing actual expenditures versus approved capital expenditures for 2016 and 2017 planned projects. For those projects with variances that exceed $50,000, it has provided commentary and analysis as to why these variances have occurred.[85]

As outlined in the tables, approved capital expenditures for 2016 and 2017 were $5.031 million and $4.860 million respectively. However, PNG-West's actual capital expenditures for the test period were $4.608 million and $4.271 million, respectively. Collectively this represents under spent capital of approximately 10 percent over the test period.[86]

These numbers increase significantly when carry forward projects (which for the most part are unbudgeted) are taken into account. In 2016-2017 unbudgeted amounts spent on carry forward capital projects totalled $1.276 million against a budget of $78 thousand. When the unbudgeted carryover project expenditures are deducted the actual under expenditure of capital dollars approved totalled $2.209 million or 22 percent.

In 2016 the most significant under spending related to recurring projects while in 2017 non-recurring projects were the primary contributor to capital funds which were unspent. PNG-West identifies projects where the under-expenditures are attributed to factors such as the economic downturn in the area, deferrals or cancellations that are beyond its immediate control. However, PNG-West also identifies projects that were not completed due to budgeting errors, scheduling problems and procurement issues.[87]

BCUC determination

The Panel acknowledges and accepts that to some degree variances in capital expenditures over a test period are to be expected. Of concern to the Panel though, is the magnitude of the under expenditures and the number of these due to scheduling or procurement issues that are within the reasonable control of PNG-West. The Panel notes that the reported under spending of planned capital projects by 22 percent is exceedingly high and represents significant costs that are reflected in ratepayer rates over the test period for projects that have not been completed. While some of these are due to unavoidable circumstances, the Panel is not persuaded that additional steps cannot be taken to budget, schedule and manage procurement and project implementation

[84] Exhibit B-1-1, p. 109.
[85] Exhibit B-1-1, pp. 109–117.
[86] Ibid.
[87] Ibid.

more effectively and complete more projects on a timely basis. Therefore, **the Panel directs PNG-West in its next RRA to analyse its planning and procurement process and report on the measures it has taken to minimize budgeting errors and omissions, facilitate the scheduling process and improve its procurement process to provide for timely completion of planned capital projects**.

5.0 Deferral accounts

5.1 Handling of UAF gas losses

The American Gas Association describes unaccounted for gas (UAF) as follows:

> The difference between the total gas available from all sources, and the total gas accounted for gas sales, net interchange, and company use. This difference includes leakage or other actual losses, discrepancies due to meter inaccuracies, variations of temperature and/or pressure, and other variants, particularly due to measurements being made at different times. In cycle billings, an amount of gas supply used but not billed as of the end of a period.[88]

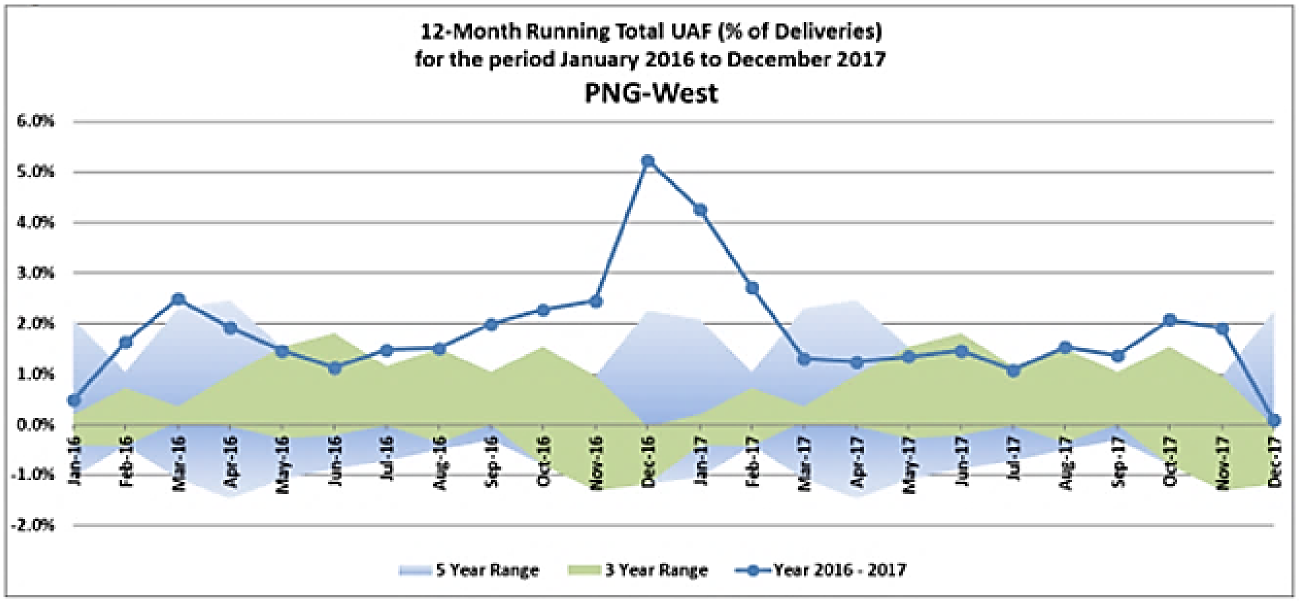
The BCUC decision in the 2016-2017 RRA proceeding, provided that PNG-West requires BCUC approval only for amounts exceeding the UAF loss cap of one percent.[89] In the 2018-2019 RRA Application, PNG-West has applied to continue the UAF volume deferral account on the basis that the forecast for 2018 and 2019 are set at zero and the practice of allowing it to record a loss between zero and one percent without further BCUC approval.[90]

On February 24, 2017, PNG-West applied for approval to allow the recording of 2016 UAF losses above one percent in the UAF deferral account. PNG-West submitted that 2016 actual UAF losses were 226,552 GJ which converts to approximately 5.2 percent of its deliveries to sales and transport customers. At the approved company used gas commodity cost of $1.927/GJ, UAF losses above 1.0 percent that would require approval amounted to $353,288 before tax.[91] Under Order G-104-17 the BCUC denied this request, and directed the company to establish a short-term interest bearing deferral account on a temporary basis to record these losses until such time as the disposition of the excess UAF (over one percent) had been determined. At that time the BCUC also directed PNG-West to prepare a report summarizing the results of its further examination of the data, calculations, and reasons for the increased losses as well as a proposal for these losses to be filed at its next RRA.[92]

As requested, PNG-West filed a UAF report summarizing its investigation of the increased UAF losses which occurred between January 1, 2016 and December 31, 2016 as part of its Application. Within the report, PNG-West identified two separate incidents where significant UAF losses occurred; the first of these was in February and March 2016 and the second in December 2016. Figure 2 below depicts the running total of UAF losses as a percentage of deliveries graphically from January 2016 to December 2017.

[88] https://www.aga.org/natural-gas/glossary/u/
[89] Exhibit B-1-1, p. 30; Order G-131-16, Directive No. 6.
[90] Exhibit B-1-1, p. 11.
[91] Exhibit B-1-1, Appendix B, p. 9.
[92] Exhibit B-1-1, pp. 30 and 135.

Figure 2 – 12 Month Running Total UAF for January 2016 – December 2017[93]



In February and March 2016, PNG-West recorded approximately 130,000 GJ of UAF losses, increasing the running total UAF to 2.5 percent of deliveries over the previous 12 months, up from 0.5 percent as of January 2016 with no significant reversal in the months that followed. This was followed in December 2016 with another large loss of approximately 60,000 GJ leading to a cumulative loss of 5.2 percent of total deliveries. Following this, in January 2017 the running total trend reversed and the UAF exhibited a declining trend culminating in the running total of UAF losses by the end of 2017 being near zero.[94]

PNG-West explains that determining monthly UAF volumes is dependent upon the unbilled estimate, which is the volume of natural gas delivered but not yet billed to customers. This is calculated by determining the number of unbilled days of service (DOS) from when a customer was last billed to the end of the current calendar month. PNG-West states that in February 2016 it implemented a change in how unbilled DOS are reported which resulted in a reduction of the estimated residential customer unbilled consumption and, as a result, an increase in the UAF loss. It estimates that this change resulted in UAF losses in the amount of 53,000 GJ. With respect to the December 2016 UAF losses, PNG-West explains this is likely a result of a residential and small commercial unbilled estimate incorrectly reflecting the impact of a significant cold snap that occurred in the middle of that month.[95]

PNG-West states that by the end of 2017 the 12-month running total UAF had dropped to a loss of only 4,703 GJ or 0.1 percent of deliveries which is well below the BCUC approved threshold of one percent. It also states that it remains diligent in the monitoring of its UAF volumes, identifying any anomalies and examining the causes of such anomalies. Looking ahead it is evaluating the costs and benefits of accessing more accurate customer information such as using advanced metering structure or the use of a new residential end-use survey in an

[93] Exhibit B-1-1, Appendix B, p. 4.
[94] Exhibit B-1-1, Appendix B, p. 3.
[95] Exhibit B-1-1, Appendix B, pp. 5–6.

effort to improve its unbilled estimate under these circumstances. PNG-West states that it has achieved a high level of confidence that the causes of the high UAF in 2016 were isolated events rather than ongoing systemic issues though its review process. As a result, PNG-West has requested BCUC approval of the UAF balance above one percent totalling 183,336 GJs or $353,288 before tax.[96]

BCUC determination

The Panel accepts the PNG-West Unaccounted for Gas Report for the Period January 2016 to December 2017 and its explanations as to the events resulting in high UAF losses in 2016. **The Panel has determined that based on these explanations it is appropriate to approve recording of the 2016 UAF losses above one percent in the UAF volume deferral account. Accordingly, PNG-West is directed to transfer those losses related to 2016 totalling 183,336 GJs valued at $353,288 before tax from the temporary UAF deferral account to the UAF volume deferral account and close the temporary UAF deferral account. There being no reason put forward to justify changing the current approved practice, the Panel also approves setting the UAF volume at zero for test year 2018 and 2019 and allowing PNG-West to record a loss of up to one percent without having to seek further BCUC approval.**

PNG-West has explained that the causes of the high UAF losses over 2016 are related to a couple of isolated incidents and are not indicative of ongoing systemic issues. The Panel agrees. However, the Panel notes that weather related incidents are likely to continue to occur in the future and, depending upon severity, timing and predictability, may lead to incorrect UAF losses given the methodology employed by PNG-West to estimate unbilled consumption and its importance in calculating UAF losses. For instance, it is possible that such an event occurred again in December 2017, where the Panel notes there was a drop of almost 2 percent in the running total UAF between the end of November 2017 and the end of December 2017 (refer to Figure 2). While this is not a matter for this proceeding and the cause of this is unknown, it does serve to demonstrate that the UAF is prone to fluctuation on a month to month basis and, when occurring over a year end, may create problems effecting the UAF and future rate rider requirements. Given these circumstances the Panel encourages PNG-West as it has indicated to continue to investigate cost-effective ways to improve its billing estimates.

5.2 Handling of LNG transportation costs from Prince Rupert

PNG-West seeks deferral account treatment for $146 thousand of LNG transportation costs from Prince Rupert and offers the following explanation for this request. Bad weather conditions in February 2018 caused a transmission line break in a remote area between Terrace and Prince Rupert that resulted in PNG-West activating its emergency system to serve its Prince Rupert customers while the line was down. In addition to requesting customers to reduce consumption, PNG-West also trucked in LNG, vaporised it and injected it into the Prince Rupert system to prevent a service outage while a permanent repair was made to the transmission line. It has forecast that the cost of trucking in the LNG (not including the $49 thousand cost of the commodity to be recovered in the GCVA) to Prince Rupert during the line break was approximately $146 thousand.[97]

PNG-West proposes to recover these costs by including them in the Line Break costs deferral account to be amortized over 2019.

[96] Exhibit B-1-1, Appendix B, p. 9.
[97] Exhibit B-3, BCUC IR 1.4.13, p. 12.

BCUC determination

The Panel approves PNG-West's request to recover the $146 thousand cost of transporting LNG to Prince Rupert during the transmission line break in February 2018. The costs are to be recorded in the Line Break deferral account to be amortized during 2019. The Panel agrees with PNG-West that this is a reasonable request to ensure continued service to its Prince Rupert ratepayers while the transmission line underwent repairs.

5.3 Option Fee Payment deferral account

PNG-West requests approval for no amortization of the LNG Partners Option Fee Payment deferral account in 2018 or 2019; plus approval to record GST of $321 thousand that PNG-West has remitted to the Canadian Revenue Agency (CRA) in this deferral account, and approval to record future option fees received in this account. PNG-West modified the latter request during the IR process and no longer seeks approval to record all future option fees received in this account. Instead, PNG-West seeks approval only to record in this account annual reservation payments of $14 thousand as stipulated per the Gas Reservation and Pipeline Lowering Agreement with LNG Canada.

In the 2016-2017 RRA proceeding, PNG-West received approval under BCUC Order G-131-16 to record Goods and Services Tax (GST) remitted to the CRA in 2015, in relation to a 2015 option fee forfeiture in the Option Fee Payment Deferral account. In the current proceeding, PNG-West requests approval to record $321 thousand of GST related to the 2016 option fee forfeiture that was remitted to the CRA in March 2016 in the same deferral account.[98] With reference to the timing of both the remittance and the request in the current proceeding to record the amount in the Option Fee Payment deferral account, PNG-West submits the following:

> On review, it appears that the $321,000 GST remittance not being addressed in the 2016-2017 RRA proceeding was an oversight. In a letter to the Commission dated March 29, 2016, PNG advised of the termination of the EDFT GTSA effective March 24, 2016. This termination triggered the $6.75M option fee forfeiture and the related GST liability of $321,000.
>
> This transaction was subsequent to PNG's submission of the Amended 2016-2017 RRA on February 29, 2016. And while the GST on the EDFT $3.25M option fee forfeiture in 2015 was addressed in the 2016-2017 RRA proceeding (see PNG responses to BCUC 1.34.3 to 1.34.9), the GST on the 2016 forfeiture was not entered on to the record for that proceeding.

PNG also requests approval to record annual reservation payments of $14 thousand as stipulated per the Gas Reservation and Pipeline Lowering Agreement with LNG Canada in this account.

BCUC determination

As requested, the Panel approves recording the March 2016 $321,000 CRA remittance related to the 2016 option fee forfeiture in the Option Fee Deferral Account. The Panel notes that PNG-West failed to disclose this amount as part of the 2016-2017 RRA proceeding which has necessitated this avoidable request.

The Panel, in reaching its determination, considered a number of factors including the size of the adjustment, the timeliness of the request, whether PNG-West acted responsibly and the foreseeability of the problem. The Panel accepts that the amount at play was a substantial amount and would have a material effect on PNG-West's ability to earn its fair rate of return. Moreover, the fee forfeiture occurred during the last RRA proceeding and could not be predicted prior to its occurrence. As they would be assigned to a deferral account, parties were

[98] Exhibit B-1-1, Exhibit B-3, BCUC IR 36.2.

aware that future rates were subject to change with no direct impact on the rates of the previous test period. However, most compelling to the Panel is that the option fee forfeited amounts to $6.75 million, all of which is to the benefit of ratepayers. The resultant GST remittance amount is a direct consequence of the option fee and should be matched against it. Although the Panel approves PNG-West's recording of the March 2016 GST remittance of $321 thousand in the Option Fee Deferral Account in this instance, PNG-West is requested to take greater care in the future to ensure omissions such as these do not occur. **As a consequence**, **PNG-West is denied the right to any carrying charges related to this CRA remittance over the 2016-2017 time period.**

The Panel also approves no amortization of the Option Fee Payment deferral account in 2018 and 2019 and for PNG-West to record annual reservation payments of $14 thousand as stipulated per the Gas Reservation and Pipeline Lowering Agreement with LNG Canada in this account.

6.0 Depreciation study

6.1 Introduction

PNG-West states that it last updated depreciation rates in 2011. In 2017, Concentric Advisors ULC (Concentric) was engaged to undertake a review of depreciation rates for all service areas based on the plant in service at December 31, 2016. PNG-West reports that consistent with the previous study, Concentric relied on various statistical methods, operation interviews with PNG staff and informed judgement based on their experience in the natural gas industry to estimate depreciation rates. For most accounts, the straight-line method using the average life group procedure for class assets has been used to calculate the annual and accrued depreciation while the annual and accrued depreciation are based on amortization accounts for certain general plant accounts. PNG-West reports that the 2017 depreciation methodologies application is consistent with that of the 2010 Depreciation study. In addition, it reports that a key finding of the Concentric 2017 Depreciation Study (Depreciation Study) that is consistent with other peer group utilities is an extension of the useful life of assets in certain accounts. When incorporated, this has effectively reduced the depreciation expense for both 2018 and 2019 Test Years.[99]

The Panel has reviewed the Depreciation Study prepared by Concentric and finds the methodology used to prepare it consistent with previous depreciation studies and resulting in a reasonable set of recommendations for depreciation rates for each service area. Therefore, the Panel accepts the Depreciation Study and depreciation expense as submitted excepting the specifically identified areas where PNG-West has deviated from the recommendations outlined. These include net salvage values, negative and positive as well as the depreciation of land rights. Each of these is addressed as follows.

6.2 Depreciation study issues

6.2.1 Inclusion of negative salvage costs

Put simply, the incorporation of negative salvage values into depreciation allows for the current and ongoing recovery of the costs of future asset removal at the end of its life. By contrast, there are certain instances where positive salvage results due to the experience of realizing proceeds on the disposition of an asset. Currently PNG-West does not incorporate negative salvage as part of its annual depreciation expense and only partially incorporates the recommendations provided by Concentric regarding positive salvage, as outlined below.[100]

[99] Exhibit B-1-1, pp. 58–60.
[100] Ibid.

Concentric's recommendations for handling negative salvage

In the 2017 Depreciation Study Concentric specifically recommends that negative salvage values be incorporated into the depreciation rates for certain accounts. This recommendation has been made with reference to PNG-West's current practice of foregoing the provision for the estimated costs of asset retirement and recording actual costs of removal at the time they are incurred.[101]

Concentric states that the incorporation of negative salvage results in a $3.0 million increase or 30 percent of PNG's total depreciation forecast.[102] While acknowledging the impact of including negative salvage, Concentric explains that delaying negative salvage introduction "will increase the inter-generational inequity from customers that pay for the eventual removal costs from those that benefited from those removed assets." Concentric also states that inclusion of a negative salvage allowance provides for proper matching of expenses to revenues and intergenerational equity is assured. In support of its position Concentric notes that the allocation of negative salvage costs over the life of the asset is appropriate and equitable and is also in accord with authoritative texts and most Uniform Systems of Accounts citing those published in Alberta, Ontario, the National Energy Board of Canada and the Federal Energy Regulatory Commission (FERC). Moreover, the inclusion of negative salvage percentages is accepted widely in regulatory jurisdictions throughout North America, although not all utilities have chosen to do so. Canadian regulators that favour allowing the inclusion of net salvage rates include the following:

- The British Columbia Utilities Commission (for FortisBC Energy);
- The Alberta Utilities Commission;
- The Manitoba Utilities Board;
- The Ontario Utilities Board;
- The Régie de l'énergie du Québec;
- The Nova Scotia Utility and Review Board; and
- The National Energy Board.

Concentric explains that the problem with delaying collection until negative salvage costs are incurred is that it results in higher revenue requirements. Moreover, the longer this is delayed, the higher the depreciation rate will be. Further, each year this process is delayed results in an increase in the differential between net and calculated book value and, as a result, depreciation rates increase proportionally.[103]

In defining depreciation for regulated utilities, the FERC Uniform System of Accounts states it is, "the loss in service value not restored by current maintenance incurred in connection with the consumption or prospective retirement of property in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance." Concentric notes that the words "service value" are the operative words in FERC's definition. These are defined in FERC's Uniform System of Accounts as "the difference between the original cost and its net salvage." Negative salvage value is further defined as the salvage value of the property to be retired less the removal cost or the cost of demolishing, dismantling, tearing down or otherwise removing electric plant.

[101] Exhibit B-1-1, p. 59–60.
[102] Exhibit B-1-1, Appendix D, p. I-3.
[103] Exhibit B-1-1, Appendix D, pp. I-3 - I-6.

In Concentric's view the revenue requirements over time resulting from an "expensing as incurred" approach are greater than those that result from the accrual of negative salvage during the life of the asset in those instances where the rate of return is included in the revenue requirements. It explains that, "as net salvage accruals are recorded to the depreciation reserve, the accumulated depreciation balance in the reserve increases and reduces subsequent determinations of rate base in future periods."[104]

PNG-West's position

PNG-West states that while the incorporation of negative salvage values in depreciation rates matches the cost of the asset to the service it provides and preserves intergenerational equity, it has made the decision to not incorporate it in its depreciation rates. It explains this by pointing to the materiality of the negative salvage estimates and resulting rate impacts of incorporation of these estimates as a basis for its position. If it were accepted, the depreciation expense for 2018 would increase by $1.908 million and $1.962 million in 2019.[105] The impact of this for PNG-West ratepayers would be an increase in delivery rates by 7.7 percent in 2018 with a decrease of 0.3 percent in 2019. While not directly related to this proceeding, the impact of incorporating negative salvage on PNG(NE) rates in 2018 would be 7.1 percent for Dawson Creek/Fort Saint John (DC/FSJ), while those in Tumbler Ridge (TR) would increase by 21.4 percent with small decreases for both divisions expected in 2019.[106]

PNG-West states that it does not record a provision for the cost to ultimately retire assets because, due to the indeterminate timing and scope of asset retirements, it is not possible to make a reasonable estimate of fair market value of the liability. It points out that under ASC 410-2-25-4 of US GAAP, the fair value of an asset obligation is required only if a reasonable estimate of fair value can be made. If not, "the liability shall be recognized when a reasonable estimate of fair value can be made." In PNG-West's view, a reasonable estimate for retirement costs can only be made at the time of disposal noting that its discussion of US GAAP provisions refers to asset obligations related to legal obligations as there is no requirement to provide provisions for removal of asset costs which do not arise from a legal obligation.[107]

PNG-West acknowledges that it would consider offsetting the immediate impact of incorporating negative salvage on customer rates by amortizing the Option Fee Payment Deferral Account. However, it notes that the PNG(NE) utility does not have an equivalent credit deferral account to offset the negative salvage recording impact and does not foresee implementing different accounting treatments between divisions. With respect to the costs related to the implementation of negative salvage into depreciation rates, PNG-West asserts that it cannot determine the extent of the costs at this time. To do so, it would need to assess the viability of using its existing financial system to record the negative salvage values and there may potentially be a requirement for one-time system changes.[108]

PNG-West states that if the Concentric recommendation regarding negative salvage were adopted, it would consider a long transition period given the significant delivery rate impact on what are already the highest rates in BC. To this end, PNG-West states it would propose a 10-year phase-in period. In doing so, it points out that, "as the net salvage recommendations are incorporated into the depreciation rates the calculations will catch up any resultant expense deficit over each affected plant account's remaining lives." PNG-West provides an

[104] Exhibit B-1-1, Appendix D, pp. I-4 - I-5.
[105] Exhibit B-1-1, p. 59.
[106] Exhibit B-3, BCUC IR 22.1; PNG NE, Tumbler Ridge, Exhibit B-3, BCUC 20.1, DC/FSJ, Exhibit B-5, BCUC 25.2.
[107] Exhibit B-3, BCUC IR 25.1.
[108] Exhibit B-3, BCUC IRs 22.3.2 and 24.2.

example where it envisions phasing in the approximate $2 million provision for negative salvage value by adding $200 thousand a year over the 10 years. Over this period, "it would continue to make use of depreciation rates without the net salvage and to record the entries…as a journal entry."[109]

BCUC determination

Concentric makes a strong case for the inclusion of negative salvage in depreciation rates where required. While the inclusion of negative salvage in depreciation rates is not universal among North American regulatory jurisdictions, it is widely accepted. Moreover, in its view, the incorporation of negative salvage in depreciation rates is effective in matching the cost of the asset to its provision of service in a manner that best addresses intergenerational equity which PNG-West acknowledges. On these points the Panel agrees. If negative salvage were incorporated, ratepayers who enjoyed the benefits of the service would also pay for its removal at its life end. This appropriately matches costs with service and ensures that future ratepayers are not saddled with costs for services they did not enjoy or did so only on a limited basis. Moreover, as stated by Concentric, if negative salvage is not incorporated, higher revenue requirements and rates will result.

PNG-West in its discussion of ASC 410-2-25-4 of US GAAP states that it is not possible to make a reasonable estimate of the fair market value of the liability as this can only be made at the time of disposal citing US GAAP provisions with respect to the removal of asset retirements where there are legal obligations. While we agree that determining the fair market value at the time of disposal will result in a better estimate of costs, we do not agree that this provides sufficient justification to forego moving ahead with negative salvage. This is especially true when this option is viewed in the context of tomorrow's ratepayers being forced to incur costs more appropriately charged to today's ratepayers. While negative salvage rates are based on estimates, these estimates are made by a qualified expert in depreciation costs and negative salvage values. While they are unlikely to be completely accurate, on balance they are likely to be reasonable in that they more appropriately match costs with service and, to the extent possible, protect the future ratepayer. **Based on the evidence presented, the Panel determines that the inclusion of negative salvage in depreciation rates is appropriate.** However, the Panel is mindful that this must be done in a manner that considers the impact on current rates. **Therefore, the Panel directs PNG-West to do so in accordance with the following directive.**

As noted by both Concentric and PNG-West the issue with including negative salvage in this case is the immediate impact on rates which is significant for PNG-West and the PNG(NE) FSJ/DC division, but extremely severe in the case of the PNG(NE) TR division. Because of this, PNG-West has proposed that if Concentric's negative salvage recommendation is adopted, the BCUC should consider a long phase in period of 10 years. The Panel agrees that given the immediate impact on rates, a phase-in period is appropriate. However, it is unclear as to how long that phase-in period should be. **Therefore, PNG-West is directed to file with the BCUC within 45 days of issuance of this Order a report detailing the following:**

- **The impact on PNG-West and PNG(NE) rates for each of the following phase-in time periods; 3 years, 5 years, 7 years and 10 years;**
- **A description of how PNG-West and PNG(NE) intend to handle the accounting for negative salvage over the phase-in period, and the method it proposes to use to charge customers over the phase-in period; and**
- **A cost estimate applicable to PNG-West and PNG(NE) for any required system changes to handle negative salvage and options for their implementation.**

[109] Exhibit B-3, BCUC IRs 22.3.1 and 69.3.

The rates effective January 1, 2019, will remain interim pending the review of the above-noted compliance filing and the BCUC's determination on the timing of the phase-in period for negative salvage accounting.

6.2.2 Positive salvage

PNG-West states that the 2010 Depreciation Study recommended positive salvage values be incorporated into depreciation rates for Account 484, Transport Equipment and Account 485, Heavy Work Equipment. It reports that the recommendation for Account 484 from the 2010 study was followed due to its experience of receiving proceeds from the disposition of these assets. However, on the basis of the company's experience of not realizing any proceeds on disposition of Account 485, it opted not to incorporate positive salvage. PNG-West states that after further review it concurs with the recommendations of Concentric in the current Depreciation Study and agrees that 10 percent would be an appropriate provision for Account 485 net salvage. If incorporated the depreciation expense would be lower by $34,800 in 2018 and $35,200 in 2019. PNG-West states that its preference would be to adopt this recommendation to coincide with implementation of provisions for negative salvage.[110]

BCUC determination

In accordance with recommendations of the 2017 Depreciation Study and PNG-West's assessment, the Panel directs PNG-West to incorporate positive salvage for Account 485 in its depreciation rates. As requested by the company this change will coincide with the timing and methodology for incorporation of negative salvage in depreciation rates.

6.2.3 Depreciation of land rights

PNG-West states that consistent with the 2010 Depreciation Study, the 2017 Depreciation Study recommends land rights be depreciated over a period of 75 years. PNG-West asserts that in the past it had determined that land rights had an indefinite life and should not be depreciated; a position it continues to take in the current Application. If depreciation of land rights were incorporated the impact on depreciation would be greater by $34,800.[111]

In making an assessment that land rights have an indefinite life and therefore should not be depreciated, PNG-West offers the following explanation:

> All agreements for provincial right of ways and providing for access to fee simple lands imply access for an indefinite period of time. This in indicated by the use of contractual language such as: "so long as required by grantee", "in perpetuity", "as long as desired by grantee" to describe the term for which many of these agreements apply. With the introduction of the BC Oil and Gas Commission in 1999, the standard term for provincial government agreements for land rights was changed to a period of 30 years, with provision to be a "monthly occupier" thereafter, subject to all provisions of the original agreement unless a written agreement is entered into to the contrary. Registered statutory right of way agreements with private landowners continue to be issued with terms that are perpetual in nature.

[110] Exhibit B-1-1, p. 59; Exhibit B-3, BCUC IR 21.1.1; PNG-West Final Argument, p. 15.
[111] Exhibitb-1-1, pp. 58–59.

PNG-West continues, stating that its access under existing land rights has not been challenged nor is it expected to be in the future as, under the Land Titles Act and the Gas Utility Act, it has the right to expropriate land on which its assets are situated. Nonetheless, it acknowledges that it is unaware of any other Canadian gas distribution utility that applies the same land rights methodology and confirms the normal accounting process is to amortize land rights.[112]

BCUC determination

The Panel directs PNG-West to amortize the value of land rights effective in 2019, in accordance with the recommendations in the Concentric Depreciation Study. While PNG-West has provided assurances to the contrary the Panel is not persuaded that over the longer term these land rights will continue in perpetuity. Perhaps more importantly, this approach is standard accounting practice among other Canadian utilities and there is no reason it should not apply to PNG-West.

7.0 Other matters

7.1 Service quality metrics

Pursuant to BCUC Order G-192-11 accompanying the BCUC decision approving AltaGas' acquisition of PNG, PNG was directed to report on a number of key service quality metrics.[113] The directive in that Order stated:

> PNG and its subsidiary shall report on the Identified Service Quality Metrics for the last two preceding years in each annual revenue requirement filed with the Commission until the Commission indicates otherwise.

In its Application, PNG-West provided in Table 56 its report on seven Identified Service Quality Metrics (Metrics) on an annual basis for the preceding five year period (2013 to 2017 inclusive).[114] Those Metrics are as follows:

- Number of Emergency Calls;
- Average Response Time per Call;
- Number of Calls with Response Time over 40 Minutes;
- Number of Underground Leaks;
- Number of Reportable Environmental Incidents;
- Lost-time Injury Frequency Rate; and
- Customer Complaints to the BCUC.

Based on the results shown in that report, the Panel is satisfied that the selected Metrics have not shown any significant deteriorating trends over the past five years. The one apparent exception pertains to the number of underground leaks which have almost doubled in 2017 compared to 2016 (27 versus 15 leaks). However, PNG-West has explained, to the satisfaction of the Panel, that underground leaks vary from year to year and are primarily due to ground movement, especially related to frost heaves, which are beyond PNG-West's control.

[112] Exhibit B-3, BCUC IR 29.1; 29.3 and Exhibit B-6, BCUC IR 74.1.
[113] Order G-192-11, Directive No. 2.
[114] Exhibit B-1-1, s. 3.3, p. 132, Table 56.

Furthermore, PNG-West reassures the Panel that all leaks have been minor in nature and addressed immediately, and that, as a proactive measure, it continues to conduct commercial and district leak surveys on a set schedule to help locate and correct any underground leaks.[115]

Concerning the adequacy and sufficiency of the Metrics, PNG-West states that it compares its Metrics with those used by other utilities across Canada, but the results are not directly comparable because of each utility's unique circumstances given differences in size, location and geography. For example, PNG-West's small size and large service territory by necessity influence its response time to customers in remote areas when compared to large urban utilities.[116]

BCUC determination

While the Panel believes that key service metrics that are benchmarked to those in industry would be more useful and meaningful as a measure of performance, it does not wish to be overly prescriptive in this area by arbitrarily setting benchmarks for PNG-West to meet without canvassing the field. However, the Panel encourages PNG-West in future applications to bring forward its own proposal for benchmarked key service metrics which will better inform future performance assessment. **In the meantime, the Panel directs PNG-West to continue to report on the Identified Service Quality Metrics for the previous two preceding years in each annual revenue requirement application filed with the BCUC.**

7.2 Capital structure and rate of return

PNG-West allowed return on equity (ROE) and common equity were established in the BCUC Generic Cost of Capital Stage 2 proceeding, effective January 1, 2013, by Order G-47-14, and the accompanying decision dated March 25, 2014 (March 25, 2014 Decision). PNG-West was measured against the FortisBC Energy Inc. (FEI) benchmark utility. In that proceeding, PNG-West was awarded an allowed ROE is 9.50 percent which is 75 basis points above the benchmark and a common equity component for PNG-West at 46.5 percent.

In its March 25, 2014 Decision, the BCUC found that PNG-West faces significantly more risk than the benchmark with respect to customer growth and its impact on demand and throughput.[117] At that time, it was stated that it was important to ensure that PNG's business risk assessment remains contemporary and its cost of capital is aligned with it. Accordingly, the PNG utilities were directed to include an updated business risk assessment in all future RRAs.[118]

As part of the Application, PNG-West filed a consolidated business risk assessment update for 2018 for all divisions as noting that they face similar risks.[119] PNG-West considers that its business risks for each of its entities have been trending higher since 2012 (i.e. lack of LNG and mining industries, climate change policies, electrification policies, and gas supply risks). However, PNG-West does not propose any changes to its capital structure and ROE as the change has not been overly substantive at this time.[120]

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[115] Exhibit B-6, PNG Response to BCUC IR 2, 94.1.
[116] Exhibit B-3, PNG Response to BCUC IR 1, 54.1.
[117] March 25, 2014 Decision, pp. 102, 113–114.
[118] March 25, 2014 Decision, p. 114.
[119] Exhibit B-1-1, Appendix G, p. 1.
[120] Exhibit B-1-1, Appendix G, p. 6.

In response to information requests, PNG-West filed DBRS credit rating reports for 2015, 2016 and 2017 on a confidential basis, which cover all three divisions on a consolidated basis. PNG-West submits that its credit rating remains the same at BBB (low) over the last five years.[121] Furthermore, natural gas commodity prices continue to be lower than 2012 and 2016 and have been less volatile.[122]

Panel discussion

The Panel acknowledges that PNG-West has filed the 2018 update of its business risk assessment in compliance with Order G-47-14, and that PNG-West is not seeking any changes to its allowed ROE and capital structure at this time. Based on the evidence presented, the Panel agrees that there is no immediate need for a change to allowed ROE on the current common equity component as the risk profile has not changed substantially. As market conditions and utility business environment change, the Panel believes that the appropriateness of the utility's cost of capital should be reviewed as part of the rate setting process. Therefore, the Panel expects that PNG-West will continue to include an updated business risk assessment in all future RRAs, as directed in Order G-47-14.

[121] Exhibit B-3, BCUC IR 50.1
[122] Exhibit B-3, BCUC IR 51.2.