IN THE MATTER OF

PACIFIC NORTHERN GAS LTD.
(PNG WEST DIVISION)

2013 REVENUE REQUIREMENTS APPLICATION

DECISION

August 1, 2013

BEFORE:

D.A. Cote, Commissioner/Panel Chair
C.A. Brown, Commissioner
C. van Wermeskerken, Commissioner

TABLE OF CONTENTS Page No.

EXECUTIVE SUMMARY

On November 30, 2012, Pacific Northern Gas Ltd. (PNG, PNG West) filed its 2013 Revenue Requirements Application (RRA) with the British Columbia Utilities Commission (Commission), pursuant to sections 58-61, 89 and 90 of the *Utilities Commission Act* (UCA). On March 4, 2013, PNG filed an update to its 2013 RRA, reflecting changes since the initial Application (Exhibit B-1-1). PNG seeks approval of an across-the-board interim and permanent rate increase resulting from increases of cost of service and decreased delivery to some customer classes. PNG, among other things, seeks approval of the following:

- Recovery in its rates of a projected revenue deficiency of approximately $454,000.
- Recovery of the AltaGas Ltd. Service charge to PNG of $750,000.
- A drawdown of $1.200 million of deferred income taxes as a credit to the 2013 income tax component.
- The cost allocators and level of shared service cost recovery by PNG from Pacific Northern Gas (N.E.) Ltd. (PNG(N.E.)), as set forth in the Application.

The Commission Panel (Panel) identified three issues which arose within the proceeding that provided context to the review of the Application. These issues and their respective determinations or conclusions are as follows:

<u>The Growth Rate of Expenses</u>

The growth rate of expenditures is significant. While offset for a time by the amortization of credit balances from a number of sources, the Commission Panel is concerned large rate increases will be required if offsetting revenue increases related to business development are not achieved. The Commission Panel concludes that given the uncertainty of the future, care must be taken to ensure that expenses are carefully managed to the extent possible.

<u>Importance of Productivity Management</u>

There are concerns as to whether PNG conducts its business in a manner that promotes processes to actively seek out and create efficiencies and manage costs. The Panel concluded that a more sustained approach to sustained productivity management is an area to be addressed in the next RRA.

Frequency of Revenue Requirement Proceedings

The efficiencies to be gained by extending the period between RRA proceedings from one to two years were considered. The Panel directs PNG to file its next RRA for a two year period.

In its review of the Application, the Commission Panel has examined and considered positions of the parties with respect to a number of issues. The most important of these issues relate to the following areas:

i) Forecast Gas Deliveries	ii) Administrative and General Expense
iii) Operating and Maintenance Expenses	iv) Rate Base

A brief summary of some of the key issues, considerations and determinations related to these areas are as follows:

(i) Forecast Gas Deliveries

The rates that PNG will require over the 2013 test period are significantly affected by sales volume forecasts. PNG has used a forecasting methodology, which is consistent with those approved in previous years. No concerns were raised by the interveners with respect to either the forecast estimates or the methodology. The Commission Panel is satisfied that the level of accuracy is reasonable and accepts the forecasts for all customer groups.

(ii) Administrative and General Expenses

PNG seeks approval for Administrative and General Expenses totalling $9.770 million for test year 2013 (before transfers to capital) representing a 17.7 percent increase over Decision 2012. The most significant impact on Administrative and General Expenses flows from proposals for wages and benefits, proposed inter-affiliate charges and shared services cost recovery.

Wages and benefits account for the largest part of the increase in expenses. With respect to wages, the Commission Panel is not persuaded that PNG has adequately justified the need for two new Head Office positions and denies the $180,000 forecasted for them. The Panel approves the 3 percent salary increase costing $65,000, but is not persuaded there is a need for the newly introduced Mid Term

Incentive Plan (MTIP) at a cost of $98,000. Considering these reductions, the Commission Panel approves total wages of $2.576 million for Administrative and General Expense.

Employee benefits increased significantly due to higher company pension costs and non-pension post retirement benefits (NPPRB). The Commission Panel accepts that pension benefit and NPPRB costs are actuarially determined and reflective of current financial market conditions as submitted by PNG. Accordingly, the Panel accepts the forecast amount of $2.809 million for pension and NPPRB costs for the 2013 test period.

PNG proposes inter-affiliate charges of $750,000 for 2013 with reference to its historical costs as a standalone entity. The Commission Panel is not persuaded that PNG's use of deferred share unit (DSU) and mark-to-market adjustments in its calculation methodology is appropriate. The Panel finds that $621,312 which excludes these adjustments is appropriate and reasonable.

As part of this Application, PNG filed a Shared Services Study to support its cost recovery from PNG(N.E.). The Shared Services Study was thoroughly reviewed and favourably evaluated by the independent accounting firm, KPMG. The Commission Panel places significant weight on KPMG's evaluation and approves the proposed cost pools, cost allocators and the level of cost recovery from PNG(N.E.) subject to required changes outlined in the Decision.

(iii) Operations and Maintenance Expenses

PNG seeks approval of $8.794 million for operating expenses and $624,000 for maintenance expenses for the 2013 test year. These costs are similar to those of 2012 and no significant issues emerged in this area during the Commission Panel's review. The Panel finds the requested amount to be fair, just and reasonable.

(iv) Rate Base

There are a number of rate base related issues considered within this proceeding. The most important of these include capital additions, PNG's deferred income tax drawdown and the handling of some deferral accounts.

PNG has forecast capital additions of $4.299 million, including capital overhead, an amount which is similar to the average of the past three years. The most significant of these expenditures is for mobile equipment ($507,000), computer equipment and licenses ($310,000), new distribution mains ($277,000) and the Rio Tinto Alcan Modernization Project ($887,000). The Commission Panel approves capital expenditures of $3.337 million, which reflects a reduction of $75,000 to proposed mobile equipment capital expenditures and a reduction of $887,000 related to the Rio Tinto Modernization Project.

PNG proposes to amortize $1.2 million of its deferred income tax balance ($8.9 million) as a credit to the 2013 test year income tax. This amount is in addition to the $2.525 million to be amortized on a consolidated basis over a six year period as directed by the 2012 Pension and Non-Benefits Application Decision. The Commission Panel accepts PNG's proposal for 2013 and directs PNG to amortize any remaining balances over a five year period on a straight line basis.

PNG seeks a number of approvals relating to its existing deferral accounts. The Commission Panel, in making its determinations, has applied the principles for treatment of deferral accounts previously established in the FortisBC Inc. 2012-2013 RRA Decision. These principles dealt with the appropriate financing charge and the appropriate length for an amortization period. The Commission Panel has made a number of determinations on deferral accounts which change the earned return from a weighted average cost of capital (WACC) to a weighted average cost of debt (WACD). In addition, the Panel has reduced the amortization period for a number of deferral accounts considering the need for intergenerational equity to be balanced against an appropriate level of rate smoothing.

1.0 INTRODUCTION

1.1 Background

Pacific Northern Gas Ltd. owns and operates a natural gas transmission and distribution system that serves approximately 20,300 customers, including residential, commercial and large industrial operations, in a region extending west of Prince George to the tidewater at Kitimat and Prince Rupert. In addition, PNG provides propane vapour distribution to the community of Granisle. (Exhibit B-1, Executive Summary, p. 1)

PNG operates the western transmission and distribution system, while Pacific Northern Gas (N.E.) Ltd. (PNG(N.E.)), the wholly owned subsidiary of PNG, operates the north-eastern transmission and distribution system. PNG(N.E.) serves some 19,000 customers in the Fort St. John (FSJ), Dawson Creek (DC) and Tumbler Ridge (TR) areas of north-eastern British Columbia. While PNG(N.E.) and PNG West are affiliated and share some costs, PNG(N.E.) files separate and distinct RRA's with the Commission.

On December 20, 2011, PNG's shares were purchased by AltaGas Ltd. (AltaGas), a public company. Consequently, PNG experienced the transition from being a public company to becoming a wholly owned subsidiary of a public company. There are costs and benefits associated with this transition. These include increased inter-affiliate charges balanced against better access to debt and capital markets.

In the context of the PNG 2013 RRA, there are a number of matters that the Commission Panel (Panel) must be mindful of. Some matters that have an impact on this Application include:

- The Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. 2012 Pension and Non-Pension Benefits Application (Pension Application) was filed separately on November 30, 2012. By Order G-189-13 on June 4, 2013, the Commission issued a decision (Pension Decision), which has implications for the current Application.

- The potential for growth of the Liquefied Natural Gas (LNG) industry in northern BC may result in greater opportunities for PNG. As of the close of evidentiary record for this proceeding, there are no finalized agreements that can be relied upon.
- PNG has received Commission approval to use US Generally Accepted Accounting Principles (US GAAP) for regulatory accounting and reporting purposes, from January 1, 2012 to December 31, 2014 (Order G-168-11). This is PNG's second RRA under US GAAP.
- By Order G-20-12, the Commission initiated the Generic Cost of Capital proceeding, which considers, among other things, the appropriate cost of capital for BC utilities. The first stage, which set the cost of capital for the benchmark utility FortisBC Energy Inc. has been completed (Order G-75-13). The second stage will directly impact the capital structure and return on equity for PNG.

PNG invoices its customers for its services in the following categories: Basic Monthly Charge; Delivery Charge; Company Use Rate Rider; Revenue Stabilization Adjustment Mechanism (RSAM) Rate Rider; Commodity Charge; and Gas Cost Variance Account Rate Rider. The scope of this Application does not include Commodity Charge or the Gas Cost Variance Account Rate Rider.

1.2 Application and Approvals Sought

On November 30, 2012, PNG filed its 2013 RRA (Exhibit B-1), which was updated on March 4, 2013 (Exhibit B-1-1) requesting, among other things, its delivery rates pursuant to sections 58 to 61 of the UCA. PNG forecasts a 2013 revenue deficiency of approximately $454,000 comprised of a net increase in cost of service of $618,000 offset by an increase in margin of $164,000 (Exhibit B-1-1, p. 2); these are subject to a number of adjustments and corrections identified in the information request (IR) process.

PNG also requests refundable interim relief, pursuant to sections 58 to 61, 89 and 90 of the Act, to allow PNG to amend its rates on an interim basis, effective January 1, 2013 (Exhibit B-1, Application, p. 1). An updated list of approvals sought is included in Appendix A.

1.3 Legislative Framework

PNG filed the 2013 RRA pursuant to sections 58-61 and 89-90 of the UCA. Section 59 (1)(a) of the UCA provides that a public utility must not make, demand or receive an "unjust, unreasonable, unduly discriminatory or unduly preferential rate" for its services. The UCA further provides that the Commission Panel is the sole judge of determining whether a rate is unjust or unreasonable, or whether there is undue discrimination, preference, prejudice or disadvantage respecting a rate (s. 59(4)). Specifically, the UCA sets out the parameters for rate setting. It provides that a rate is unjust or unreasonable if it is more than a fair and reasonable charge for service of the nature and quality provided by the utility (59(5)(a)) or if it is "insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property" (59(5)(b)).

1.4 Regulatory Process

PNG filed its original application on November 30, 2012 requesting, among other things, that its proposed rates be approved on an interim basis, pursuant to sections 58 to 61, 89 and 90 of the UCA. By Order G-192-12, delivery rates and the RSAM rate rider were approved on an interim basis, effective January 1, 2013 and a Preliminary Regulatory Timetable was established. An Amended Preliminary Regulatory Timetable was established on January 15, 2013, setting separate IR dates for the Shared Services study (Order G-3-13).

For a number of years, PNG's RRAs were determined through the Negotiated Settlement Process (NSP). In 2012, PNG's RRA was reviewed through a written hearing process. Having a written hearing in 2013 is appropriate given that PNG's shares were recently purchased by AltaGas and PNG seeks to pursue opportunities available in its region, including LNG.

In accordance with the Amended Preliminary Regulatory Timetable, the Commission received submissions from the British Columbia Pensioners' and Seniors' Organization et al. (BCPSO) regarding the regulatory process. BCPSO submitted that they do not support an NSP and they suggest a written public hearing process. In response to a Commission letter dated March 7, 2013 requesting submissions from PNG on the regulatory process, the Commission received submissions from PNG indicating that they were not opposed to a written public hearing process. The Commission considered the submissions received and by Order G-42-13, dated March 20, 2013, established a written public hearing process and a Further Amended Regulatory Timetable.

The Peace River Regional District and BCPSO registered as Interveners in this proceeding and BCPSO actively participated.

On March 4, 2013, PNG filed updates to the 2013 RRA (Exhibit B-1-1) to reflect the impact of the year-end 2012 Actual figures on the forecast 2013 cost of service, in addition to several other adjustments to the 2013 cost of service.

1.5 Approach to this Application

A number of important issues arose within this proceeding that provide context to the review of this Application. These include: (i) the growth rate of expenses, (ii) the importance of productivity improvement and (iii) the frequency of RRA proceedings. These are discussed in Section 2 of this Decision. Section 3 deals with PNG's forecast for gas deliveries and issues related to them. An examination of issues related to Administrative and General Expenses is undertaken in Section 4, followed by a review of Operations and Maintenance Expenses in Section 5. In Section 6, a variety of issues are raised with Rate Base implications and finally, in Section 7 the Panel examines a number of issues raised within the proceeding and provides determinations or direction where appropriate. A list of suggestions for improvement to the preparation of RRAs for future proceedings is also provided.

2.0 CONTEXTUAL ISSUES

2.1 Growth Rate of Expenses

In the last decade PNG has faced significant challenges with the loss of large industrial customers like Methanex Corporation, which closed its methanol/ammonia complex in Kitimat in 2005 and West Fraser Mills, which ceased operation in 2010. The loss of these customers was a serious threat in that it resulted in less demand for natural gas within PNG's service area and less use of its transportation capabilities. This in turn resulted in higher customer rates.

PNG is under the new ownership of AltaGas and PNG continues to develop a working relationship with its parent company. Looking ahead, it appears to the Commission Panel that PNG's business prospects have begun to improve and there is potential for significant revenue growth over the next few years. However, the Panel is concerned that neither the certainty nor the magnitude of these potential revenue sources is definite. At the same time we note the significant growth in expenses in certain areas which, over the short term, will be partially offset by credit balances being amortized into rates over the next few years. The Panel's concern is that once these amounts have been fully amortized, the current level of expenses cannot be maintained without significant rate increases or a substantial increase in throughput volume resulting in higher revenues. Therefore, given the lack of certainty of future revenues, we remain cautious in our outlook.

Until recently, PNG was a public company traded on the Toronto Stock Exchange. As noted, AltaGas acquired all of the common shares of PNG and consequently, PNG is now a wholly-owned subsidiary of AltaGas. It is PNG's position that the relationship with AltaGas will have a positive effect on results. In support of this, it submits that the AltaGas acquisition eliminates the need for many of the expenses related to maintaining its public reporting status as well as creating a number of operating efficiencies. Further, PNG expects that the parent company AltaGas Utility Group will provide certain utility services to PNG including items such as strategic and financial planning and general advice and assistance. In exchange for these services, AltaGas has imposed service charges on PNG which total $1.620 million (PNG does not propose to include the full amount in rates at this time). (Exhibit B-1, pp. 12-13; BCUC 1.22.4; BCUC 2.39.4)

The Commission Panel is of the view that PNG is best described as a utility in transition given the relatively short period of time since the acquisition of PNG by AltaGas. Because of this, we acknowledge that all of the potential benefits PNG might expect from the acquisition by AltaGas may not have materialized. Notwithstanding, the Panel notes that services and benefits provided by AltaGas come at a significant cost to PNG.

The Commission Panel also acknowledges that the utility has prospects for greater use of its transmission facilities due to the potential for growth of the LNG business within British Columbia. Construction of LNG plants and the increased need for natural gas transportation capabilities may well provide greater utilization of PNG's capabilities. In support of this, PNG anticipates a positive rate impact related to the commencement of toll payments by LNG Partners that are expected in 2015 (Exhibit B-1, p. 24). However, in recognizing that the current outlook is certainly brighter than that which existed during the last decade, the Panel is mindful that there are no firm volume commitments in evidence.

As noted, the Commission Panel is concerned with the rate of growth of certain expenses over this transitional period of adapting to new ownership and leading to potential growth of LNG business within the province. In this Application, PNG West forecasts overall Operating, Maintenance and Administration and General Expenses to be $19.188 million (excluding transfers to capital and company use gas cost), an increase of $1.750 million or 10 percent over 2012 expenditures. Much of this change is related to Administration and General Expenses, which at $9.770 million represents a $1.465 million or 17.6 percent increase over 2012 actual (Exhibit B-1-1, p. 2). Offsetting this, there are three areas which must be considered:

- Shared Services Cost Recovery from PNG(N.E.);
- The Impact of the West Fraser Termination Payment;
- The Impact on Amortization Expense of amortized credits in the LNG Deferral Account and Deferred Income Taxes.

Shared Services Cost Recovery

PNG is proposing a new shared services cost allocation methodology. This will result in increasing the allocation of costs from PNG West to PNG(N.E.) from $2.377 million to $3.141 million, an increase of $764,000 or 32.1 percent. Therefore, notwithstanding the merits of a new cost allocation methodology, PNG West is, in effect, proposing to allocate a substantial part of its overall increase in costs in the 2013 test year to PNG(N.E.). The shared cost allocation methodology is addressed in Section 4.4.

The Impact of the West Fraser Mills Termination Payment

When West Fraser Mills terminated its contract with PNG it made a contract termination payment of $5.152 million to PNG. Subsequently, in the 2011 RRA Negotiated Settlement, the parties agreed to record the amount in an interest bearing deferral account and amortize the payment in equal amounts as a credit to cost of service. The last credit payment will be fully amortized on December 31, 2013 (Order G-92-11, p. 3).

Impact of LNG Deferral Account and Deferred Income Taxes

PNG is proposing to amortize in 2013 one half of the year-end 2012 credit balance in the LNG Partners Option Fee Payment deferral account with any remaining balance to be applied to 2014. The amortization credit impact for 2013 is $1.689 million. (Exhibit B-9, BCUC 2.59.3) PNG is also proposing to apply $1.200 million of the remaining Deferred Income Tax account as an amortization credit. The application of remaining amounts in this deferral account will be addressed in Section 6.3.

The Commission Panel notes that the combined impact of these offsets has the effect of reducing total expenses substantially to a more modest 3.9 percent (Exhibit B-1-1, p. 2).

Commission Panel Discussion

PNG West ratepayers have been shielded from significant rate increases by the reallocation of costs to PNG(N.E.). In addition, the combined impact of the West Fraser Mills termination payment, the amortization credits from the LNG Deferral Account and the Deferred Income Tax Account serve to offset cost increases and soften the impact on rates. If there were no termination payment or amortization credits, with no increase in revenues, the Panel estimates an impact on current rates in the 20 to 25 percent range, depending on rate class. Given that the positive impact of these measures will begin to decline at the end of 2013 due to credit balances being exhausted, the Panel is of the view there is cause for considerable concern regarding future rates for PNG West customers if offsetting revenue increases are not achieved.

Further, PNG is requesting that only a portion of the $1.620 million in additional costs related to services provided by AltaGas be charged in rates in the 2013 test period. PNG states its position on future applications as follows:

> "In the future, as the economic circumstances of PNG's business improve, as PNG fully expects, PNG expects to seek recovery of all costs allocated by its parent company associated with maintaining its capital structure, providing access to capital and delivering the various other services..." (Exhibit B-1, p. 13)

The Panel understands there is potential for additional revenue related to the LNG business. However, the Panel notes that while there are contracts in place for the use of capacity on the PNG system, there is no evidence detailing the impact on revenue. Therefore, given the uncertainty of the future, care must be taken to ensure that expenses are kept in check to the extent possible.

2.2 Importance of Productivity Management

PNG provided little evidence related to its productivity management processes in this proceeding. This raises concern given the significant increase in expenses and the issues raised in Section 2.1 with respect to the need for careful management of expense additions.

In BCUC IR 1.2.1, PNG was asked what steps have been taken within the past year to streamline the company, increase efficiency and manage costs. In response PNG stated that the utility has a long history of "demonstrated organisational efficiency and cost management" pointing out that, as a consequence, additional improvements are limited. PNG also noted that it will continue to pursue economies of scale through procurement opportunities with AltaGas. Further, when asked directly as to planned actions during the current year, the utility responded:

> "In 2013 and beyond PNG will continue to search for new and effective ways to streamline the company, increase efficiency and manage costs while delivering the safe, reliable service our customers expect and deserve. However, with PNG's past efforts in this area and existing lean organisational structure PNG is unable to point to specific actions other than those already discussed in this proceeding..." (Exhibit B-3, BCUC 1.2.2)

PNG points out that because of the increasingly strong economic activity in its service area and the additional administrative burden and reporting requirements being requested by outside parties, additional resources may be needed (Exhibit B-3, BCUC 1.2.2).

Commission Panel Discussion

The Commission Panel acknowledges that PNG has begun the process of pursuing economies of scale with its new parent AltaGas and will continue to pursue opportunities in the future. While such initiatives are helpful, they are not enough. The Panel is of the view there is an ongoing need for utilities to manage their business in a manner that promotes processes to actively seek out and create efficiencies and manage costs. This transcends pursuing what might be termed "low hanging fruit" resulting from the new subsidiary relationship with AltaGas and needs to be expanded to include a full review of PNG as an organisation.

From PNG's responses noted above, it is apparent that while PNG seems committed to the idea of searching for new ways to increase efficiencies and potentially lower costs, there are no formal processes in place to ensure this is actually accomplished. The Panel is not persuaded that PNG has taken adequate steps to ensure that its apparent commitment to productivity improvement is being met. At the very least, an organisation committed to managing productivity must have processes in place to conduct periodic reviews of the functions performed, whether they can be done more efficiently or whether they need to be done at all. An example of a process where changes are likely to result in cost saving improvements is the frequency of revenue requirements proceedings which is discussed in Section 2.3. A more formal approach to sustained productivity management processes is an area the Commission Panel expects to see addressed in PNG's next RRA.

2.3 Frequency of Revenue Requirement Proceedings

PNG has an established practice of preparing its RRAs on an annual basis. This is unique in that other utilities typically submit RRAs covering a period of at least two years. A RRA is a significant undertaking in terms of time, effort and cost on the part of the utility, the interveners and the Commission. A utility must prepare and file the initial application, prepare for and attend a Procedural Conference where required, which is followed by the preparation of responses to IRs filed by the Commission and interveners. Once this has been completed the utility must prepare its final and reply submissions or, in the case of an NSP, spend time preparing for the process. For interveners and the Commission, the process is not dissimilar and is very time consuming. Therefore, by the time the Commission Panel issues a decision on an application, a considerable amount of cost has been expended which is ultimately reflected in customer rates.

Commission Determination

The cost of preparing and filing an application covering a two year period rather than a one year period is certainly greater given the increased span of time covered. However, there are economies of scale and cost efficiencies to be gained for both the utility and the ratepayer by handling an application covering a two year time span rather than a single year at a time. Given this fact, the Commission Panel is of the view that filing future RRAs covering a time span of two years is both administratively efficient and prudent from a cost perspective. **Accordingly, the Commission Panel directs PNG to file its 2014 RRA for a two year period.**

3.0 FORECAST GAS DELIVERIES

3.1 Forecast by Customer Group

PNG forecasts Total 2013 deliveries of 3,813,645 GJ (Exhibit B-1-1, Tab Rates, p. 6). Deliveries are split between the following customer classifications:

- Residential
- Small Commercial
- Granisle Propane
- Small Industrial
- Large Industrial
- Large Commercial Sales.

In addition, PNG serves other Core Market Customers which include Commercial Transport, Seasonal Off-Peak and Natural Gas Vehicle (NGV) Customers. (Exhibit B-1, Application, pp. 55-58)

3.1.1 Residential and Small Commercial Customers

Forecasting for Residential and Small Commercial customers is based on historical trends and data. PNG states that it does not use housing start statistics as a proxy to forecast customer additions. PNG also states that while some municipalities in the service area are expected to experience economic growth, the projects that are expected to create this growth are still in the early stage of development and are not expected to result in a growth in Residential and Small Commercial customers in the next year or two (Exhibit B-9, BCUC 2.74.1).

PNG operates a Commission-approved RSAM deferral account for both Residential and Small Commercial customers. This deferral account tracks variances between forecast and actual sales volumes, pertaining to Residential and Small Commercial customers. The RSAM helps to stabilize the effects on forecasts of unforeseen circumstances over which the utility has no control, such as weather. While the account tracks differences of revenue in use per account variations, it does not track variations in the number of customers. The RSAM is discussed further in Section 6.

Residential Customers

PNG is requesting approval of forecast 2013 deliveries of 1,204,152 GJ to its Residential Customers, based on the forecast average use per account of 68.2 GJ/year and the forecast weighted average customer count of 17,631 customers (Exhibit B-1-1, Tab Rates, p. 8). The 2013 forecast deliveries show an increase of 22,000 GJ as compared to Decision 2012[1]. PNG is forecasting a net loss of 73 Residential Customers as compared to Decision 2012 but the forecast use per account is up from 66.5 GJ/year in Decision 2012 reflecting recent trends. PNG continues to use the forecasting methodology that has been accepted by the Commission in previous years (Exhibit B-1, p. 56; Exhibit B-9, BCUC 2.74.1; Exhibit B-1-1, Tab Rates, p. 8).

Commission Determination

The Commission Panel notes an improvement in gas delivery forecast accuracy in recent years, as compared to the period starting in the year 2000 (Exhibit B-10, BCUC Confidential 2.2.1). Further, the Panel notes PNG's expectation of a time lag between the current early stage of development in the area and consequent growth in Residential and Small Commercial Customers. Moreover, the Panel notes that having in place an RSAM further mitigates the impact of forecast error. **Given these factors and the fact that the forecasting methodology is consistent, the Panel finds PNG's forecast to be reasonable. The Commission Panel accepts PNG's 2013 forecast weighted average customer count of 17,631 and the forecast use per account of 68.2 GJ/year. Accordingly, the Commission accepts PNG's Residential forecast deliveries for the current test period of 1,204,152 GJ.**

Small Commercial

PNG seeks approval for forecast 2013 deliveries of 783,212 GJ to its Small Commercial Customers, based on the forecast average use per account of 317.2 GJ/yr and the weighted average customer count of 2,465 customers (Exhibit B-1-1, Tab Rates, p. 8).

[1] In the Matter of Pacific Northern Gas Application for Approval of its 2012 Revenue Requirements for the PNG-West Service Area – Commission Order G-130-12, September 21, 2012.

In 2013, PNG forecasts a net loss of 15 Small Commercial Customers compared to Decision 2012 (Exhibit B-1-1, Tab Rates, p. 8). PNG also forecasts an increase in use per account as compared to the Decision 2012 amount of 309 GJ/year.

Commission Determination

The forecasting methodology utilized by PNG is consistent with that used in previous PNG RRAs. In addition, the Panel notes that the RSAM offers the ratepayer a level of protection from the impact of forecasting error.

The Commission Panel accepts PNG's 2013 forecast weighted average customer count of 2,465 and the forecast use per account of 317.2 GJ/year. Accordingly, the Commission accepts PNG's Small Commercial forecast deliveries for the current test period of 783,212 GJ.

3.1.2 Granisle

PNG seeks approval of the Granisle forecast 2013 propane deliveries of 8,418 GJ, based on the forecast average use per account of 56.5 GJ/year and the weighted average customer count of 149 customers (Exhibit B-1-1, Tab Rates, p. 8). This forecasting methodology is reasonable and consistent with the methodology used in previous PNG RRAs.

Commission Determination

The Commission Panel accepts PNG's 2013 forecast weighted average customer count for Granisle of 149 and the forecast use per account of 56.5 GJ/year. Accordingly, the Commission Panel accepts PNG's forecast Granisle propane deliveries of 8,418 GJ for the current test period.

3.1.3 Small Industrial

PNG seeks Commission approval of the 2013 forecast deliveries to its Small Industrial Customers. PNG's Small Industrial Customers are comprised of firm sales and both firm and interruptible transportation customers. PNG forecasts 2013 deliveries of 151,750 GJ to firm sales customers and 514,175 GJ to transportation service customers, for a total of 665,925 GJ. (Exhibit B-1-1, Tab Rates, pp. 8-9; Exhibit B-1, p. 57)

The projected 2013 deliveries are based on the forecasts obtained from PNG's small industrial customers. This forecasting methodology is reasonable and consistent with the methodology used in previous PNG RRAs.

Commission Determination

The Commission Panel accepts the 2013 deliveries forecast to Small Industrial customers as filed with the Commission in the Application in the total amount of 665,925 GJ.

3.1.3.1 Conifex

Conifex is a small industrial customer that, since 2008, has been handled in a different manner than other small industrial customers. PNG submits that Conifex was included in the Industrial Customers Delivery Deferral Account (ICDDA) starting in 2008 as a result of the interveners and PNG being unable to agree upon an appropriate load for the new customer Conifex in that year's RRA (Exhibit B-3, BCUC 1.56.2).

The issue for the Commission Panel is whether the accuracy of the forecasts are at a point where it would be appropriate to remove Conifex from the ICDDA and handle it in the same manner as other small industrial customers. The evidence suggests that since 2008 there has been an improvement in the variance between Actual and Forecast deliveries. In percentage terms, the level of variance has ranged between 5.6 percent and 28.2 percent over the past 4 years. However, as PNG notes, the absolute error in the Conifex margin has averaged less than $100,000 in these same 4 years. (Exhibit B-3, BCUC 1.56.4)

PNG submits that its expectation was that once Conifex had developed a reliable operating history, it would no longer be included in the ICDDA. Further, PNG submits that it would not be opposed to Conifex being removed from the ICDDA (Exhibit B-3, BCUC 1.56.3 and 1.56.4; Exhibit B-9, BCUC 2.76.1).

Commission Determination

In the view of the Commission Panel, Conifex has achieved a more reliable operating history resulting in better forecasting. Therefore, the rationale for the continued use of the ICDDA to capture Conifex's forecast variations is no longer valid. **Accordingly, the Commission Panel directs PNG to remove Conifex from the ICDDA and treat Conifex as a Small Industrial Customer for 2013 and onwards.**

3.1.4 Large Industrial

PNG seeks Commission approval for forecast 2013 deliveries of 710,614 GJ to Large Industrial Customers, allocating 686,614 GJ to Rio Tinto Alcan (Firm and Interruptible) and 24,000 GJ to BC Hydro (Interruptible) (Exhibit B-1-1, Tab Rates, pp. 8-10). Rio Tinto Alcan forecast deliveries are substantially lower than the previous year forecast deliveries due to the impact of modernization project activities on its smelter operations. The BC Hydro delivery forecast is consistent with historical deliveries during the years when BC Hydro only operates its generating station to keep it in a "ready to operate" mode in case of an emergency (Exhibit B-1, Application, p. 58).

Commission Determination

The forecasting methodology is consistent with PNG's previous RRAs and the explanations given for the decrease in forecast deliveries are reasonable. Accordingly, **the Commission Panel accepts the 2013 forecast deliveries for Large Industrial Customers as submitted by PNG.**

3.1.5 Large Commercial Sales

PNG seeks Commission approval of forecast 2013 deliveries of 79,297 GJ to Large Commercial Firm Customers, and 47,000 to Large Commercial Interruptible Customers, for a total of 126,297 GJ to all Large Commercial Sales Customers (Exhibit B-1-1, Updated Application, Tab Rates, pp. 8 and 10).

The 2013 forecasting methodology is reasonable and is consistent with PNG's previous RRAs.

Commission Determination

The Commission Panel accepts the 2013 delivery forecast for Large Commercial Sales Customers as submitted by PNG.

<u>Other Core Customers</u>

PNG forecasts 2013 deliveries of 290,327 GJ for Commercial Transport customers (Rate 22 and Rate 33), 8,200 GJ for NGV customers, and 16,500 GJ for Seasonal Off-Peak customers (Exhibit B-1-1, Tab Rates, p. 8). These forecasts are based on a review of historical deliveries and customer contact information (Exhibit B-1,, p. 57). The 2013 forecasting methodology is reasonable and is consistent with PNG's previous RRAs.

Commission Determination

The Commission Panel accepts the 2013 forecast deliveries for Commercial Transport (Rate 22 and Rate 33), NGV and Seasonal Off-Peak customers as submitted by PNG.

3.2 Allocation of Revenue Deficiency

PNG allocates the revenue deficiency to customer classes using the normalized forecast gross margin as the allocator for each customer class. The Panel reviewed the allocation methodology employed by PNG and concludes that it is consistent with prior test periods and reasonable.

3.3 Demand Side Management

PNG has suggested that very little of its resources should be dedicated to Demand Side Management (DSM) activity, as the marginal retail prices of gas is generally well in excess of the marginal cost of gas (Exhibit B-1, p. 63). The Applicant contends that this factor, in and of itself, is effective in promoting DSM and is concerned with the administrative costs associated with DSM programs.

While BCPSO did not make any mention of the DSM issues in its final submissions, they noted, "silence on any particular issue should not be construed as consent" (BCPSO Final Submission, p. 1).

Subsequent to the filing of this Application, the Commission released its Decision for the PNG(N.E.) Resource Plan (Order G-60-13). In that Decision, PNG(N.E.) was ordered to resubmit the DSM portion of the 2012 Resource Plan, in order to comply with subsection 44.1(2) (b) of the UCA, which requires a public utility to file a plan that includes cost-effective demand-side measures.

Commission Determination

Consistent with the PNG(N.E.) Resource Plan Order, the Panel directs PNG to consider section 44.1(2) of the UCA and DSM when filing its 2013 Resource Plan.

4.0 ADMINISTRATIVE AND GENERAL EXPENSES

PNG seeks approval of Administrative and General Expenses totalling $9.770 million for test year 2013 before transfers to capital. This is an increase of $1.471 million or 17.7 percent over the Decision 2012 approved forecast. Of this amount, wages and benefits account for 69 percent of these expenses and collectively account for $1.188 million of the increase in costs over the Decision 2012. (Exhibit B-1-1, Tab 1, p. 2)

4.1 Administration and General Labour Cost Increases

4.1.1 Wages

Administrative and general wages for 2013 are forecast at $2.854 million, which represents an increase of $392,000 or 15.9 percent over Decision 2012 (Exhibit B-1-1, Tab 1, p. 2). PNG attributes increases in this area to three factors:

Two new Head Office Positions	$180,000
An overall salary increase of 3 Percent	$65,000
An increase in Incentive Compensation	$146,000

Two New Head Office Positions

PNG states that both of these positions are a reflection of greater activity in the finance and accounting area that to this point have been addressed by outside consultants and to a lesser extent, existing staff. PNG reports that one of the positions, Manager Commercial Development and Financial Planning, was hired on January 1, 2013 at a salary grade lower than what had been forecasted. No job description has been finalized for the Senior Financial Analyst position and presumably it has not been filled (Exhibit B-1, p. 10; Exhibit B-9: BCUC 2.32.1, BCUC 2.32.2.1).

PNG was not specific as to the cost of outside consultants to perform these functions in previous test periods and the evidence provided does not support a corresponding reduction in consultant costs to reflect the two new positions. PNG estimates a cost of $500,000 if consultants were to provide the service (Exhibit B-3, BCUC 1.19.6). In addition, amounts forecasted for contractors and consulting fees in the 2013 test period while, approximately $70,000 lower than 2012 actual, are close to what was forecasted for the 2012 test period (Exhibit B-9, BCUC 2.30.1).

BCPSO notes that there appears to be considerable similarity between the roles of the two positions. BCPSO urges the Commission to consider whether both positions are required (BCPSO Final Submission, p. 3).

PNG submits that both positions are required and outlines tasks which the Manager, Commercial Development & Financial Planning has undertaken since being hired in January, 2013. PNG submit that the second manager is necessary to alleviate the overtime hours currently being worked to deliver on regulatory requests, financial reporting and disclosure requirements (PNG Reply Submission, p. 3).

Overall Salary Increase of 3 Percent

PNG states that it has budgeted for an increase of approximately 3 percent for its salaried non-bargaining unit administrative employees pointing out that this amount was 3.5 percent in the 2012 test period. This is in contrast to the 2 percent for bargaining unit employees which was negotiated in the most recent collective agreement (Exhibit B-1, p. 10).

Increase in Incentive Compensation

PNG states that the additional incentive compensation requirements are $146,000 for the 2013 test period. Short term incentive compensation amounts are slightly higher to reflect the three management level hires in 2012 and the 3 percent planned salary increase. However, the largest part of this increase, $98,000, is as a result of PNG non-union employees now being eligible for the AltaGas MTIP (Exhibit B-3, BCUC 1.20.5). PNG states that the purpose of the MTIP program is as a facilitator to the retention of experienced employees thereby reducing the costs of employee turnover. The MTIP provides for the grant of phantom shares to PNG employees and the vested shares provide for a cash payment to the employee. MTIP rewards long-term commitment to the utility and represent less than 3 percent of the total non-bargaining unit budget. PNG submits that this is a modest investment in the retention of employees who have eligibility to participate in the plan (Exhibit B-1, pp. 10-11; Exhibit B-3, BCUC 1.21.3).

BCPSO submits there is no evidence to suggest that employee turnover is an issue and therefore, there is no need for any new incentives (BCPSO Final Submission, p. 3).

When questioned as to the need for the MTIP program in light of its nominal turnover rate, PNG responded that AltaGas provides the program for all its subsidiaries and it has been implemented for internal equity reasons along with general competitive reasons (Exhibit B-9, BCUC 2.36.1).

PNG acknowledges that the turnover rate for non-union employees over the past 5 years has been nominal. However, it reports that AltaGas has experienced benefits of boosted morale and reductions in turnover when the program was introduced at its other operations. Further, PNG notes that proactively introducing the program will address the looming labour challenges in British Columbia. PNG was unable to provide any current examples of similar programs in place in BC utilities (Exhibit B-3, BCUC 1.21.1, BCUC 1.21.2 and BCUC 1.21.8).

PNG in reply states that it has submitted sufficient evidence to justify the inclusion of the MTIP in the compensation package as appropriate given the marketplace where it competes for resources (PNG Reply Submission, p. 3).

Commission Determination

Two New Head Office Positions

The Commission Panel has a number of concerns with the PNG proposal to add the two new positions. First, the Panel notes that in the 2012 test period two new positions were added to the Finance and Business Development Department and, with the proposed new positions, the complement would increase to 10 people. This is a 66 percent increase over 2011 (Exhibit B-3, BCUC 1.11.1). Second, there does not appear to be a corresponding offset in consulting fees to accommodate the two new positions. While actual contractor or consulting fees were higher than forecast in the 2012 test period (Exhibit B-9, BCUC 2.30.1), there has been no explanation as to why or whether this over expenditure is in any way related to the Finance and Business Development Department. Third, there is not sufficient evidence to justify these positions or a fulsome explanation as to why over the last two years, the staff complement is required to be increased by 66 percent. In addition, the Commission Panel notes that by PNG's admission, one of the positions has yet to be filled and a job description has yet to be prepared in spite of test period 2013 being well underway. **Given these concerns, the Commission Panel denies the $180,000 requested by PNG for the two additional positions.**

The Commission Panel notes that in response to BCUC IR 2.25.1, PNG forecasts less reliance on consultants and contractors. Based on the information provided, PNG expects to reduce overall numbers of contractors from 7 to 2 in comparison to 2012 with savings of $310,000. From this information it is not readily apparent how much is related to specific projects which came to an end and how much was related to functions to be undertaken by the two new positions. Moreover, it is not apparent where the $310,000 in savings can be attributed. What is clear is that consulting fees in Account 722 are $84,000 or 31 percent higher than the amount approved in the Decision 2012 (Exhibit B-1-1, Tab 1, p. 5) and in Account 721 are $20,056 or 6.8 percent less than the amount approved in the Decision 2012 (Exhibit B-9, BCUC 2.30.1). The Panel acknowledges that there are one-off consulting costs for 2013 in Account 722 (Exhibit B-1-1, p. 6) but notes that there are also one-off expenses in 2012 for the Shared Services Study and the Executive Compensation Review in 2012 which will not be repeated. In future RRAs PNG is encouraged to display their consultant and contractor expenses in tabular form and detail project based expenditures which will not carry forward from one test period to the next, those that will and those which are new. If actions like this are undertaken at the application stage, there will be less need for IRs designed to 'ferret' out this information which will reduce confusion and result in greater efficiency.

Salary Increase

With respect to the proposed overall salary increase of 3 percent, the Commission Panel notes that PNG has provided no explanation for providing its salaried non-bargaining unit staff with a wage increase which exceeds the amount negotiated with the bargaining unit by 1 percent. However, the Panel understands that there is no reason to expect the terms of the collective agreement to mirror those of non-bargaining unit employees. Likewise, the same can be said for bargaining unit employees. There is no reason to expect that terms agreed to within the collective agreement are provided to non-bargaining unit staff. **The Commission Panel finds that the proposed salary increase is not unreasonable given the size of increase and the amount approved in the Decision 2012. The 3 percent salary increase costing $65,000 is approved as it falls within a reasonable range for salary increases.**

Incentive Compensation Increase

The Commission Panel has concerns with respect to the addition of the MTIP program and the value it adds to the ratepayer. PNG has acknowledged that its turnover rate is nominal but notes that it expects to compete with companies offering similar compensation programs in the future. The Panel is not persuaded there is sufficient evidence to support the need for this program or whether it will be a determining factor in an employee leaving or staying with PNG now or in the future. **Therefore, the Commission Panel denies the inclusion of the $98,000 for this program in rates. The Commission Panel accepts PNG's explanation and approves the remaining $48,000 to cover incentive payments for the three new employees added in 2012 and the approved salary increase of 3 percent.**

Taking these reductions into account, the Commission Panel approves a total of $2.576 million in Administrative and General wages which is a reduction of $278,000 from the amount proposed by PNG.

4.2 Employee Benefits

Employee benefits are forecast at $3.996 million for the 2013 Test Period representing an increase of $789,000 over the Decision 2012 (Exhibit B-1-1, Tab 1, p. 5). A significant portion of this proposed increase relates to higher company pension and NPPRB. For greater clarity the general employee benefit costs and issues will be addressed separately from those related to pension and NPPRB expenses.

4.2.1 Employee Benefits – General

The largest employee benefits category other than Company Pension is for Other Programs. PNG has used the Other Programs category to distinguish them from more standard benefits such as life and disability insurance, unemployment insurance, employee savings plans, medical and hospital expenses and workers compensation benefit (WCB) costs.

Other Programs

Forecast costs for Other Programs total $753,000 which is a 39 percent increase over the Decision 2012 and 2012 actual expenses (Exhibit B-1-1, Tab 1, p. 5). PNG state that 90 percent of Other Program costs relate to NPPRB expenses which will be addressed in Section 4.2.2 (Exhibit B-3, BCUC 1.32.2).

Within the Other Programs category are two smaller programs with significant percentage increases forecast for 2013: Employee Service Awards and the Educational program (scholarship program for employee children and tuition reimbursement for employees). Educational expenses, although a relatively minor amount, is forecasted to increase by 64 percent in the 2013 test year. PNG states its budget for this program is based on an assumption of how many employees' children apply for post-secondary scholarships under the PNG program and actual applications vary. The estimate for the current year is $14,855, which compares to an average over the last three years of $3,018. The cost of the Employee Service Awards program is also forecasted to increase significantly in 2013. Employee Service Awards are forecast to increase to $18,405 in 2013, which is almost three times the $6,560 spent in 2012. PNG notes that the additional expense relates to a large number of service awards which were earned in 2012 that will be redeemed in 2013 (Exhibit B-3, BCUC 1.32.1.1; Exhibit B-9, BCUC 2.17.2 and 2.17.3).

Employee Benefit Programs

PNG has a range of common employee benefit programs including life and disability insurance, unemployment insurance, medical and hospital insurance and WCB. A modest increase is proposed for each in test year 2013.

PNG also offers a savings plan benefit to its employees. Costs related to the employee savings plan are forecasted at $379,000 and represent an increase of $73,000 over 2012 Actual (Exhibit B-1-1, Tab 1, p. 5). PNG states that this is a reflection of the increase in the maximum company match amount from 5 percent to 6 percent which came about through the recently negotiated contract with its union, the International Brotherhood of Electrical Workers. PNG submits that the company matching contribution is related to the employee's length of service with the maximum being achieved after 6 years of service. The program is open to all employees with by far the largest number, due to length of service, falling in the maximum company contribution category (Exhibit B-1, p. 17; Exhibit B-3, BCUC 1.34.4).

Commission Determination

The Commission Panel acknowledges that the expense amounts related to the Employee Education and Service Award programs are small but in our view the forecasts prepared for them should nonetheless be reasonable. PNG notes that the applications for educational assistance vary and amounts approved may be higher or lower than forecast but have provided no evidence with respect to an expected increase in the number of applications for 2013. In consideration of this and the lack of evidence to suggest there will be an exceedingly high number of applications in 2013, the Panel is not persuaded that there is justification to forecast an amount for this program which is over four times the average of the past three years.

The Panel has similar concerns with the Service Award program. In response to BCUC IR 2.17.4, PNG outlined the number of employees that were estimated to receive awards by length of service category. Relying upon the reported average cost per award as outlined in answer to BCUC IR 2.17.5, the cost of 2013 awards should be approximately $4,500. If the nine awards which were not redeemed in the previous year as noted in response to BCUC IR 2.17.2 were taken into account, the maximum additional expense would be slightly over $6,300 (4x $840 plus 5x $595). When combined, the maximum requirement for 2013 should be no more than $10,800 against the forecast of $18,405. **The Commission Panel finds the lack of attention to such detail in the preparation of 2013 forecasts unacceptable. The Panel directs PNG to reduce its 2013 forecast for Educational Expense and Employee Service Award programs by an amount totalling $15,000.** The amount of the reduction to be applied to each account is left to PNG's discretion.

With respect to the employee savings plan benefit, in addition to the 51 Bargaining unit employees eligible for the program, 24 non-bargaining unit and 4 executive employees are also included (Exhibit B-3, BCUC 1.34.4). As the Panel understands it, the increase from 5 to 6 percent as the maximum amount was a benefit negotiated by the union for its members. Further, as noted in the discussion in Section 4.1.1, the terms for non-bargaining unit employees do not directly mirror those of bargaining unit employees as evidenced by the difference in salary increases between the two groups. Therefore, the Commission Panel, while noting that PNG at its own discretion has decided to offer this additional benefit to non-union employees and the executive, is not persuaded there is justification for the additional costs related to the increase from 5 to 6 percent to be borne by the ratepayer. **The Panel directs PNG to recalculate this amount and any amounts related to the 1 percent increase in the non-union and executive groups are to be charged to the account of the shareholder.**

4.2.2 Employee Benefits – Pension and Non-Pension Post Retirement Benefits

On November 30, 2012, PNG filed a Pension Application. PNG states that this Application reflects the handling of pension and NPPRB plan expenses and funding requirements which have been sought by PNG in its Pension Application. The Decision was issued on June 4, 2013; within its Reasons for Decision, the Commission Panel made the following statement:

> "The Panel excluded from the scope broader revenue requirement related issues, such as whether PNG should be allowed to continue to recover the cost of a defined benefit pension plan in rates or whether the non-pension post retirement benefits are excessive from a rate setting perspective" (Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. 2012 Pension and Non-Pension Benefits Application, Order G-89-13, Appendix A, p. 1).

Pension Retirement Benefits

PNG states that a significant part of the overall increase in total employee benefit expenses is due to higher Company pension and NPPRB costs. Overall, pension benefit costs are forecasted to increase by 31.5 percent from $1.619 million in Decision 2012 to $2.130 million in 2013 (Exhibit B-1-1, Tab 1, p. 5). PNG submits that the reasons for this are mainly due to a decrease in the actuarial determined discount rate from 5.1 percent in 2012 to 4.1 percent in 2013. The lower discount rate is a result of current financial market conditions. In addition there has been a decrease in the expected return on plan assets (Exhibit B-1, p.17; Exhibit B-1-1, p. 5).

Non-Pension Post Retirement Benefits

The costs of NPPRB total $679,000 which is $200,000 or 41.7 percent more than 2012 (Exhibit B-9, BCUC 2.14.1). The cost for these, like pension benefits, is determined by an actuary and has increased due to a declining discount rate. PNG reports that the premium for these would also have increased significantly had PNG not marketed its benefit coverage with AltaGas resulting in a lower premium rate increase than it could have achieved on its own. PNG provides no insight as to the magnitude of costs which were avoided (Exhibit B-3, BCUC 1.32.2).

Commission Determination

The Commission Panel accepts the reasons for the increase in pension and NPPRB expenses and further accepts that while the cost increases are substantial, they are justified. **Therefore, the Panel approves the forecast amount of $2.809 million for pension and NPPRB costs for the 2013 test period**. However, we are nonetheless concerned that the cost of these programs is reaching a point where they are becoming unaffordable. In addition, the Panel is not satisfied that there is sufficient evidence that these programs, as they are currently structured can be justified given the recent sharp increase in the costs. **Accordingly, the Commission Panel directs PNG to provide a detailed justification of pension and NPPRB as part of its next RRA.** The Panel also expects PNG to provide the Commission with potential options it may be considering as a way to control future cost growth in these areas as part of the next application.

In summary, PNG is directed to reduce overall employee benefits cost by $15,000 plus any amounts related to the 1 percent reduction of the amount proposed for the employee savings plan for non-union and executive management employees.

4.3 Other Administrative and General Expenses

Other expenses cover a wide range of categories including: audit, legal and consulting fees, donations, regulation, AltaGas service charges, insurance and corporate memberships, among others. The 2013 Forecast for most of these categories is very similar to Decision 2012. However, two areas do stand out – AltaGas service charges and Public and Government Relations. PNG has proposed an increase in AltaGas service charges from $404,000 in the Decision 2012 to $750,000 or an increase of 85 percent. In addition, PNG has forecasted $65,000 for Public and Government Relations (Exhibit B-1-1, Tab 1, p. 5; Exhibit B-1, p.18).

4.3.1 <u>2013 Proposed Inter-Affiliate Charges</u>

PNG has calculated that its average annual cost to operate as a standalone public company is approximately $815,000. However, PNG is proposing to include an inter-affiliate charge for the 2013 test year of $750,000 in its cost of service. (Exhibit B-1, p. 13) This proposed charge is an increase of $346,000 over the Decision 2012 figure. The $750,000 proposed by PNG is a number that PNG suggests “has been developed in reference to its own historical costs when it was a standalone publicly reporting entity” (Exhibit B-1, p. 13). PNG provides the following arguments to support the notion that $750,000 is a reasonable number:

- AltaGas has allocated proposed charges of $1.62 million to PNG (Exhibit B-3, 1.22.3).
- Additional costs incurred by similar sized independently listed companies, to operate as standalone public companies average $1 million (Exhibit B-1, p. 12).
- PNG’s average annual public reporting and shareholder expenses for the years 2009-2011 when it was a standalone public company were $815,293 (Exhibit B-1, p. 14).
- The inter-affiliate service charge for 2013, using the AltaGas allocation methodology used in Decision 2012, is $805,000. (Exhibit B-3, BCUC 1.22.1.1).

As noted previously, PNG has indicated that it intends to recover the entire AltaGas service charge from ratepayers once its economic circumstances have improved (Exhibit B-1, p. 13).

BCPSO has raised concerns respecting the increase of inter-affiliate charges of $346,000 as compared to Decision 2012. Specifically, BCPSO submits that an appropriate charge from PNG’s parent ought to start with recent historic costs to operate as a standalone public company, reduced for “expected efficiencies due to central provision and… [elimination] of any ineligible cost components contained therein” (BCPSO Final Submission, p. 3). Accordingly, BCPSO suggests $621,312 as an appropriate starting point, which is the three-year average annual costs to operate as a standalone public company of $815,293, less the mark-to-market valuation and notional dividends related to the deferred share units (DSUs) (see Table 1).

There are two issues that the Commission Panel has identified in this regard: i) the reasonableness of the proposed inter-affiliate charges; and ii) the appropriateness of the AltaGas allocation, which is discussed in Section 7.1.

4.3.1.1 The Reasonableness of the Proposed Inter-Affiliate Charges

PNG submits that the proposed increase of inter-affiliate charges of $346,000 over Decision 2012, for a total proposed charge of $750,000, is reasonable. Its’ argument is that $750,000 is less than what PNG calculates as the average annual public reporting and shareholder expenses for the years 2009-2011 when it was a standalone company and less than the average additional costs incurred by listed companies which are approximately the same size as PNG. In addition, the Panel notes this amount is less than the inter-affiliate service charge for 2013 using the previous AltaGas allocation methodology.

BCPSO submits in their Final Argument that the proposed allocation exceeds historic costs to operate as a standalone public company and therefore constitutes cross-subsidization of its parent. BCPSO suggests that any allocation in excess of historic costs to operate as a standalone public company should not be approved. BCPSO submits that an appropriate starting point for inter-affiliate charges is $621,312, which reflects the elimination of DSU mark-to-market and dividend adjustments, as described in Table 1.

Table 1

PNG-West Administrative and General Expenses Public Company Reporting/Shareholder Expenses	Actual 2011	Actual 2010	Actual 2009	Average 2009 - 2011
BCUC Account 728				
Directors' fees and expenses*	$ 480,565	$ 632,353	$ 385,668	$ 499,529
Less: DSU Mark-to market/Dividends adjustments	(120,418)	(334,707)	(126,819)	(193,981)
	360,147	297,646	258,849	305,547
Annual Report	30,551	23,494	18,399	24,148
Shareholder expenses (Computershare, TSX, Broadridge, Bowne)	94,048	75,099	79,426	82,858
Investor Relations	5,718	9,736	7,320	7,591
	490,465	405,975	363,994	420,144
BCUC Account 721				
Investor relations -(printing, accom, meals & ent, transportation)	4,432	4,328	9,313	6,024
	4,432	4,328	9,313	6,024
BCUC Account 722				
Audit fees	234,035	188,094	213,183	211,770
Internal audit fees	51,022	44,556	44,726	46,768
Legal fees	43,812	41,249	48,467	44,509
Consultant fees	55,600	49,816	60,708	55,375
	384,468	323,715	367,084	358,423
BCUC Account 723				
D&O insurance	58,000	63,500	63,500	61,667
Fiduciary insurance	23,650	24,250	24,250	24,050
	81,650	87,750	87,750	85,717
Total	**$ 961,015**	**$ 821,768**	**$ 828,141**	**870,308**
Less Audit, Legal, Consulting Fees and D&O/Fiduciary Insurance in 2013 Cost of Service				(248,996)
				$ 621,312

**2011 director's fees adjusted for share price from $27.62 at Sep 30, 2011 to sale price of $36.75 ==> reduce DSU expense by $456,757*

(Exhibit B-3, BCUC 1.24.2)

In response to BCUC IR 1.24.2 (Exhibit B-3), PNG recalculated the average 2009-2011 historic costs to operate as a standalone public company, excluding notional dividends and mark-to-market adjustments on the DSUs, to be $621,312 (Table 1). This figure is derived beginning with the historic average cost to operate as a standalone public company of $815,293, which is an average of the Applicant's public company's reporting expenses from 2009 to 2011. However, PNG Directors were compensated with either cash or DSUs in lieu of cash; these units were vested upon issuance. The units also accumulated dividend equivalents in the form of additional units and were only redeemable for cash following termination of service. For accounting and reporting purposes, the DSU's were marked to market each quarter end, and the change was reflected as Directors' fees and expenses. Historically, the non-cash notional dividends and mark-to-market adjustments on the DSUs have been removed from expenses for Commission approval. PNG submits that in previous years they only "included its estimate of directors' compensation (based on a standard fee structure of an annual retainer, Board meeting fees and Committee meeting fees) for rate setting purposes" (Exhibit B-3, BCUC 1.24.1.1). $621,312 represents the initial $815,293 average standalone charges, less the average notional dividends and mark-to-market adjustments on the DSUs of $193,981.

The Commission Determination

The Commission Panel denies PNG's claim for recovery of $750,000 in the cost of service for inter-affiliate charges. The Panel finds that $621,312 is appropriate and reasonable for the total inter-affiliate charges. This excludes the DSU mark-to-market adjustments and notional dividends. While the Panel appreciates the comparative analysis provided by the Applicant, the Panel is not persuaded that the requested amount is appropriate, noting the increase from the 2012 service charge, of approximately 85 percent.

The Commission Panel is not persuaded that adding on the DSU notional dividends and mark-to-market adjustments to calculate the average historic costs to operate as a standalone public company is appropriate. Historically, PNG has not been allowed to recover these amounts from the ratepayer. Instead, the estimate of directors' compensation based on a standard fee structure of an annual retainer, Board meeting fees and Committee meeting fees were used for rate-setting purposes. The Panel considers that the ratepayer should not be responsible for directors' fees that are related to market fluctuations and notional dividends that ultimately exceed the amount paid had the director elected to receive cash compensation instead of DSUs. Accordingly, the Panel concludes that $621,312 is the appropriate historic average cost to operate as a standalone public company to use in the determination of the appropriate inter-affiliate charge for 2013.

The Panel accepts PNG's rationale that the proposed 2013 inter-affiliate charge is developed in reference to its own historical costs when it was a standalone publicly reporting entity. Accordingly, the Panel concludes that the appropriate 2013 inter-affiliate charge is $621,312.

4.3.2 Government Relations Program

PNG was directed by the Commission in Decision 2012 to file a specific and more fulsome explanation of its government relations program and the benefits to ratepayers in the 2013 RRA. The Commission indicated in Decision 2012 that "...the underlying substance and intent behind the activities logged is the key to this analysis."

PNG provided a description of the government relations program and the nature of the expenses incurred by the program in the Application. The forecast test year 2013 expense for the government relations program is $65,000 (Exhibit B-1, p. 16), including $41,000 for sponsorship of community events across PNG's service area (Exhibit B-3, BCUC 1.27.4).

With respect to the link between the program and ratepayer benefits, PNG submits the following:

> "... PNG has taken a more active role in its government relations to ensure a higher visibility when decisions are made within our service territory. PNG's goal is to maximize volumes through our existing system and potentially expanding its infrastructure." (Exhibit B-1, p. 16)

Concerning the link between the corporate sponsorship expense specifically and ratepayer benefits, PNG submits that the events it supports are directed at the growth and prosperity of its service area. Its view is that this modest support provides aid to growth in the region which could increase its customer base and result in lower customer rates (Exhibit B-9, BCUC 2.45.2).

Commission Determination

With respect to the $41,000 corporate sponsorship expense included in test year 2013 cost of service, the Panel points to Decision 2012 where the Commission determined that: "...**PNG may only include 50 percent of its 2012 donation budget as an expense to be recovered from ratepayers.**"

The Panel considers that corporate sponsorship expenses and donations expense fall into the broader category of Community Investment. Consistent with the Commission's determination on donations expense in Decision 2012, the Panel considers that there are considerable benefits that accumulate to the shareholder from the Company's community sponsorship spending. These include the acknowledgment of PNG as a good corporate citizen supporting the brand and goodwill. **Consistent with the Decision 2012 treatment of donations expense, the corporate sponsorship budget of $41,000 is to be shared equally between the shareholder and the ratepayer.**

The Commission Panel has reviewed the explanation provided by PNG of the government relations program. Except the comments regarding the corporate sponsorship expense, the Panel finds the explanation provided reasonable.

4.4 Shared Services Cost Recovery

In Decision 2011[2], PNG West was directed to file a Cost Allocators and Level of Shared Service Cost Recovery Application as a standalone application in the fall of 2012. This was to be based on a shared service cost study prepared by a third party consultant (Shared Services Study). PNG West was also directed to incorporate a one-year time study commencing in July 2011 into the Shared Service Study to analyze the Labour Cost Allocator. As part of the Shared Service Study, PNG West was directed to include an analysis of whether Customer Care Center services provided to PNG(N.E.) from the PNG West Terrace office could be provided more economically on a standalone basis from a dedicated Customer Care Centre in the PNG(N.E.) service area (PNG 2011 RRA, Appendix A, p. 4).

On September 19, 2012, PNG filed a request with the Commission to incorporate and include the 2012 Shared Services Study as part of its 2013 revenue requirements application, rather than filing it as a separate application. The Commission granted PNG's request on October 19, 2012, by Letter L-62-12.

There are two components to PNG West's shared service allocation: cost pools and cost allocators. Historically, PNG West has used ten cost pools to capture shared costs incurred by the PNG Vancouver and Terrace regional offices for the benefit of PNG(N.E.). These cost pools have included customer care, engineering, administration and corporate services. PNG reviewed all of the cost pools to determine if certain cost pools should be added or deleted and to determine if specific cost items should be added or removed from the cost pools. As a result of the review, two new cost pools were

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[2] In the Matter of Pacific Northern Gas - Application for Approval of its 2011 Revenue Requirements and Consolidated Gas Sales Tariff for the Pacific Northern Gas Ltd.-West Service Area - Negotiated Settlement – Commission Order G-92-11, May 20, 2011.

added: Vancouver Billing Services and Terrace Technical Services – Warehouse/Corrosion (Exhibit B-1, pp. 27-42).

Cost allocators can be divided into two separate types of allocation: labour and non-labour. The labour component of the cost allocators utilizes a time-based allocator to allocate costs from the cost pools that contain a labour component, such as Vancouver Administration and the Terrace Customer Care Centre. As required by the Commission, PNG completed a new 2011/2012 Time Study, which utilized a more specific labour allocation methodology. For the non-labour component of the cost allocators, PNG changed its methodology to now use composite cost allocators, which are a combination of two or more of the following cost allocators: time-based, customer count, employee count, and rate base (Exhibit B-1, pp. 27-42).

The independent public accounting firm KPMG was engaged to evaluate the PNG West revised shared services cost allocation model and the PNG assessment of whether or not a standalone customer care centre in PNG(N.E.) would be more economical than the current shared customer care centre. KPMG found both the revised shared services model and the cost assessment for a standalone customer care centre to be reasonable and appropriate. KPMG's full report was provided in Tab 6 of the PNG West Application.

The proposed shared service cost recovery from PNG(N.E.) is $3.141 million for test year 2013, which is an increase of $764,000 from Decision 2012 (Exhibit B-12, BCUC 2.1.1). Of this total increase, approximately $302,000 is attributable to the change in shared services methodology (Exhibit B-12, BCUC 2.3.1, Table 3.1-2). The remaining $462,000 increase is a result of higher General and Administrative Expenses proposed by PNG for test year 2013.

The cost allocation percentages for the Vancouver Administration cost pool have increased significantly for both the labour cost allocator and the non-labour cost allocator. When asked to explain the cause of the increase of 10 percent in the labour cost allocator, PNG submits that the increase is due to the fact that a time study had not been completed since 2003. Since then, the staff mix and the amount of time spent by staff on PNG(N.E.) activities has increased (Exhibit B-12, BCUC 2.6.2). When asked to explain the cause of the increase of 8 percent in the non-labour cost allocator, PNG indicated that the change was caused by switching from a single allocator to the composite cost allocator. This includes the following four cost drivers: time study, customer count, employee count, and rate base. PNG believes that the new composite cost allocator is appropriate because it meets all of PNG West's established cost driver principles, in particular, cost causality (Exhibit B-12, BCUC 2.6.1).

BCPSO is concerned with the overall size of the shared services cost pools. In particular, BCPSO raises concerns over the Terrace Management and the Vancouver Administration Cost Pools, both of which BCPSO feels have increased significantly under the new shared services methodology. BCPSO argues that a "more efficient utility" can perform with the same expected reliability, customer service, and operational efficiency at a lower cost than the same "less efficient utility" performed these tasks in the past. As such, BCPSO believes that no new costs of greater than 10 percent can be justified for inclusion in either of the aforementioned cost pools. BCPSO also notes that the impacts of the proposed changes to the shared services methodology are widely varying and urges the Commission to consider these large variations before approving the new methodology (BCPSO Final Submission, pp. 4-5).

PNG disagrees with BCPSO's position that the cost pool increases are due to inefficiencies. It points out that the proposed cost pools were a result of a rationalization of historic cost pools, an examination of historically included costs and a review of costs not previously included in the pools. PNG submits that it has included costs which were always incurred but not included in cost pools historically and notes that this implies that PNG West customers have been cross-subsidizing PNG(N.E.) historically (PNG Reply Submission, p. 5).

Commission Determination

The Commission Panel reviewed the KPMG report provided in Tab 6 of the Application and finds that KPMG's evaluation of the appropriateness of the revised shared services methodology is thorough. While the cost recovery from PNG(N.E.) has increased significantly, more than half of this increase is due to the large increase in PNG West's General and Administrative Expenses, which has been dealt with in Section 4.0 of the Decision and is unrelated to the change in the shared service methodology.

The Panel has also reviewed PNG West's evaluation of whether Customer Care services provided to PNG(N.E.) from the PNG West Terrace office could be provided more economically on a standalone basis. The Panel finds that PNG's financial analysis of the costs to implement a standalone customer care centre is reasonable, particularly given that the costs have also been reviewed by KPMG and found by KPMG to be within a reasonable range. **The Panel accepts PNG's conclusion that the creation of a standalone Customer Care Centre in the PNG(N.E.) service territory is not supportable economically at this time.**

The Panel acknowledges BCPSO's concerns over the increases to certain cost pools, particularly the Vancouver Administration cost pool, and the concerns over the varying impacts of the proposed changes to the shared services methodology. However, PNG has provided adequate support for the changes to the shared services methodology and has provided linkages between the cost allocators and the cost driver principles underpinning the shared service methodology. In addition, the Commission Panel places weight on the evaluation performed by KPMG, an independent public accounting firm, and in KPMG's conclusions that the revised cost allocation methodology is reasonable and appropriate.

The Commission Panel approves the cost pools and the cost allocators as proposed in the 2012 Shared Services Study and as set forth in the Application. The Commission Panel approves the level of shared service cost recovery by PNG from PNG(N.E.) for the 2013 test year subject to the changes required to be made to PNG's Administrative and General Expenses as directed by the Panel in this Decision as well as those outlined in responses to IRs.

5.0 OPERATING AND MAINTENANCE EXPENSE

PNG seeks approval of Operating and Maintenance (O&M) expenses of $8.794 million for operating expenses and $624,000 for maintenance expenses for the 2013 test year, before transfers to capital and not including Company Use Gas, which is recovered at cost from customers (Exhibit B-1-1, Tab 1, p. 2). This is a forecast increase of $208,000 for operating expenses and a forecast decrease of $23,000 for maintenance expenses over Decision 2012, or approximately a 2 percent increase on the combined O&M budget. Wages account for approximately 56 percent of the total O&M budget and include a bargaining agreement wage increase of 2 percent over 2012 (Exhibit B-1-1, Tab 1, p. 2; Exhibit B-1, p. 10).

Certain O&M expenses which were approved as part of the Decision 2012 were not spent in 2012 due to limited resources and scheduling conflicts. PNG forecasted $30,000 in 2012 for contractor charges to create an avalanche safety plan in order to be compliant with WorkSafe BC requirements. PNG states that although the project was awarded to a specialized consultant in 2012, no field work was completed due to the consultant's commitments to projects for other organisations. PNG confirms that Actual 2012 O&M costs were reduced by $30,000 to reflect the fact that these costs are now forecast to be spent in 2013 (Exhibit B-3, BCUC 1.14.4; Exhibit B-9, BCUC 2.26.2). PNG also forecasted $36,000 in 2012 for consultants to conduct an evaluation of its Customer Information Services (CIS) due to the fact that PNG's current contract with Vertex Data L.P., the current provider of CIS services, is due to expire on December 31, 2013. This evaluation was not completed in 2012. PNG confirms that Actual 2012 O&M costs were reduced by $36,000 and are now being forecast as part of the 2013 test year (Exhibit B-3, BCUC 1.17.5; Exhibit B-9, BCUC 2.29.1).

PNG has forecasted an increase in support fees payable to Oracle of $23,000 for the test year 2013. This occurred following an audit initiated by Oracle in 2012 of the number of Oracle licenses held by PNG. The result of the Oracle audit, which was finalized in November 2012, indicated that PNG did not hold the appropriate number of Oracle licenses and therefore must now purchase additional licenses and pay an increased support fee annually (Exhibit B-1, p. 6; Exhibit B-3, BCUC 1.17.3).

Commission Determination

The Commission Panel reviewed the evidence and given the modest 2 percent forecast increase finds the 2013 forecast cost of service for Operating and Maintenance expenses of $9.418 million to be fair, just and reasonable.

6.0 RATE BASE

6.1 Capital Additions

PNG has forecasted capital additions totalling $4.299 million inclusive of capitalized overhead for the 2013 test year. (Exhibit B-9, BCUC 2.73.1) This amount is slightly less than Decision 2012 and the average capital expenditures of $4.534 million for the 2009 through 2011 three year period (Exhibit B-9, BCUC 2.72.1). PNG separates its capital expenditures into four categories:

- System Betterment (SB) – which include expenditures ensuring the safety, reliability and integrity of transmission and distribution systems as well as renewals, reinforcements and alterations to these systems to ensure adequate capacity to meet existing and forecasted load requirements.
- New Business (NB) – expenditures made to provide service to new customers (new mains, services, meters and other facilities).
- General Plant (GP) – equipment, tools, facilities and IT hardware expenditures.
- General Plant Intangibles (GP) – IT licenses and software.

In response to BCUC IR 2.73.1, PNG provided Table 2, outlined below. Table 2 provides an outline of the projects, their costs, expected completion year and the category into which they fall. Most significant of these expenditures are the following.

TABLE 2

2013 Test Year Capital Additions

Cat	Expense Type/Project Name	2013 Test Year (excluding OH)	2013 Test Year (Including OH)	Forecast Completion (Yr)	Account
Recurring Additions (Regular and routine replacements, upgrades or additions)					
GP	Mobile Equipment	$507,000	$507,000	2013	484
GP	Computer Equip/Licenses	$310,000	$310,000	2013	487
SB	Cut-outs from ILI digs	$53,000	$73,000	2013	465
SB	ROW Access, Signage, ETC (individual scope projects under $50k)	$186,000	$254,000	2013	465
SB	Meter Replacements	$161,000	$161,000	2013	478
NB	New/replacement services	$148,000	$202,000	2013	473
GP	New/replacement tools and equipment	$74,000	$74,000	2013	486
NB	New Distribution Mains	$203,000	$277,000	2013	475

Cat	Expense Type/Project Name	2013 Test Year (excluding OH)	2013 Test Year (Including OH)	Forecast Completion (Yr)	Account
	Other (less than $50,000 scope projects, total should be less than 10% of Total Additions)	$156,000	$172,000	2013	
	Subtotal Recurring Additions	$1,798,000	$2,030,000		
Planned (non-recurring) Additions (known, new and/or significant specific planned projects)					
SB	Rio Tinto Modernization	$650,000	$887,000	2013	467
SB	Replace Obsolete Actuators	$108,000	$147,000	2013	466
SB	Replace Line Heater , NGS	$81,000	$98,000	2013	467
SB	Replace Line Heater, Endako	$70,000	$96,000	2013	467
SB	Replace obsolete R2 charger	$70,000	$95,000	2013	466
SB	Replace obsolete R4 charger	$70,000	$95,000	2013	466
SB	Replace high pressure tubing	$68,000	$92,000	2013	462
SB	Paint Gitnadoix bridge	$245,000	$334,000	2013	465
	Other (less than $50,000 scope projects, total should be less than 10% of Total Additions)	$57,000	$86,000	2013	
	Subtotal Planned Additions	$1,419,000	$1,930,000		
Un-Planned Additions					
SB	Unspecified mainline repairs	$248,000	$339,000	2013	465
	Subtotal Un-planned Additions	$248,000	$339,000		
Carry Forward Projects (from previous year(s))					
	Subtotal Carry Forward Projects				
	TOTAL	$3,465,000	$4,299,000		

(Source: Exhibit B-9, BCUC 2.73.1).

Mobile Equipment ($507,000)

PNG forecasts a need for 11 replacement vehicles in 2013 and all meet its replacement criteria of seven years or 160,000 kms, which it reports as being consistent with the industry. The requirements are split between ½ ton, ¾ ton and 1 ½ ton vehicles. Six of the vehicles are 2009 and 2010 vehicles which are not fully depreciated but are expected to exceed the 160,000 km criteria during the 2013 test year (Exhibit B-1, p. 40; Exhibit B-4, BCPSO 1.17; Exhibit B-3, BCUC 1.64.3).

PNG notes that in 2012 it was able to secure considerable cost savings in vehicle purchases due to aggressive purchasing and the purchasing power of AltaGas. This resulted in savings of $75,000 on a forecast of $397,000. PNG further notes that this year's budget was prepared using manufacturer's suggested retail price because it could not guarantee that dealer or volume discounts would apply (Exhibit B-3, BCUC 1.66.1; Exhibit B-9, BCUC 2.71.4).

Computer Equipment and Licenses ($310,000)

The largest part of the required capital ($170,000) is related to additional Oracle Licenses PNG is required to purchase primarily as a result of an audit performed by Oracle of licenses held. PNG reports that it negotiated with Oracle representatives and, as a result, "reduced the amount of licenses owed which results in a one-time payment of $150,000 and the waiving of the majority of the backdated support fees" (Exhibit B-1, p. 49-50). PNG further reports that it is required to pay $50,000 for future support fees (Exhibit B-3, BCUC 1.17.3).

New Distribution Mains ($277,000)

The forecast expenditure for this area allows for the installation of new mains for additional customers as well as replacing or modifying existing facilities.

Rio Tinto Modernization ($887,000)

PNG has forecasted $650,000 (excluding capitalized overhead) to service the modernization project of Rio Tinto Alcan (RTA). PNG has acknowledged that the $650,000 is an initial rough estimate and expected to provide a better estimate in the second round of IRs. No further updates to this estimate have been received by the Commission. PNG states in BCUC IR 2.69.5 that negotiations with RTA are still underway for the project and that PNG hopes to have the project in place in the fourth quarter of 2013.

Commission Determination

The Commission Panel has a number of concerns with the proposed capital additions warranting comment and in some instances further direction.

First, the Panel is not persuaded that the forecast for the purchase price of new vehicles is justified. Given that PNG has some latitude with respect to the timing of vehicle purchases and has been successful in securing savings in the previous year, it is reasonable to expect that similar savings could be achieved.

A second concern lies in the forecast capital additions for the Rio Tinto Alcan Modernization project. The Panel notes that PNG did not provide a more accurate cost estimate for the project and that negotiations with RTA were still underway at the time of PNG filing its responses to the second round of IRs. **Therefore, the Panel denies the $887,000 capital additions for the Rio Tinto Alcan modernization project for 2013. The Panel directs PNG to place the costs incurred for the RTA project in the test year 2013 into a non-rate base, non-interest bearing deferral account. PNG is directed to apply for approval of the capital costs associated with the RTA project as part of its 2014 RRA.**

The amount and scope of forecasted capital additions is very similar to what has been spent in previous years. Moreover, the Commission Panel notes that there was very little in the capital addition request which could not be considered routine. For the most part, where queries were raised, PNG was able to provide reasonable replies. As discussed, the two exceptions to this were vehicle purchases and the Rio Tinto Alcan modernization project. **Accordingly, the Commission Panel approves the capital expenditures of $3.337 million which reflects the downward adjustments of $887,000 for the RTA modernization project and $75,000 for mobile equipment.**

6.2 Management of Capital Costs

In each of PNG's past two revenue requirements applications the issue of capital additions forecasting has been raised by the Commission. In the Decision 2012, the Commission was specific in requesting the following:

- The provision of more fulsome capital addition expenditure reporting.
- The provision of an analysis of the budget variances with respect to its capital additions forecasting.

The purpose of these requests was to allow for greater transparency concerning capital expenditures on a project by project and a year by year basis allowing for greater granularity in the review of capital expenditure tracking in future years. PNG was directed to provide this information in schedule format in its next RRA (PNG 2012 RRA Decision).

PNG acknowledges the Commission directive in the PNG 2013 RRA and notes that the requested schedule will be filed with its application update which it expected to file in late February or early March 2013. The Commission made further reference to this in BCUC IR 1.66.1 where PNG was asked to provide analysis on expense variances of greater than $25,000 and include not only the year 2012, but also the previous year 2011. PNG responded that it had neither the systems capability nor the resources to perform the work for 2011. The information and analysis was provided on 2012 variances as part of the application update on March 4, 2013 (Exhibit B-1, p. 54; Exhibit B-1-1, p. 23).

Commission Determination

The Commission Panel acknowledges that some progress has been made with respect to providing more fulsome explanations on the status of capital additions and any significant variances which exist. However, the Panel notes that the provision of this information was late in the process which limited the Commission and interveners' review to the second round of IRs only.

The Commission Panel directs PNG to provide the completed Schedule 1 report (as outlined in IR 1.66.1) on 2013 capital additions as part of its next RRA as well as an update on 2012 capital additions detailing any further variances. In addition, any project with a variance in excess of

$25,000 is to be accompanied by an explanation detailing the reason for the variance. The Panel recognizes that because of the timing of the application, the amounts shown may not be reflective of final project totals. However, we are of the view that the information, while potentially incomplete, will be useful at this stage and can be updated as the process moves forward.

6.3 Deferred Income Tax Drawdown

PNG requests approval to amortize $1.2 million of deferred income taxes as a credit to the income tax component of the 2013 test year cost of service (Exhibit B-9-1, BCUC 2.80.1). This represents an increase of $200,000 as compared to the Decision 2012 amortization amount of $1 million. The average 2013 test year deferred income tax balance of $8.3 million is a credit to rate base, thereby reducing the return on rate base included in the 2013 cost of service. The average balance is derived from the deferred income tax balance at the end of 2012 and test year 2013 of $8.9 million and $7.7 million, respectively (Exhibit B-1-1, Tab 2, p. 12).

From July 1, 1978 until its suspension on November 6, 1986, PNG used the normalized method of accounting for income taxes. The deferred income tax balance is the historical recovered deferred income tax expense from this time period. Since then, PNG recovers income taxes using the flow through method. (Exhibit B-3, BCUC 1.54.1-2)

The Commission directed PNG in the Pension Decision to amortize $2.525 million of the deferred income tax balance on a consolidated basis over six years, commencing January 1, 2013, to offset the amortization of the NPPRB Regulatory Asset Deferral Account.

The deferred income tax balance does not have a set amortization period. In determining the appropriate drawdown amount each year, PNG submits that "...PNG considers its financial situation, the impact on current customer rates and the impact on future customer rates particularly given PNG's expectations about the path of future customer rates" (Exhibit B-3, BCUC 1.54.5).

With respect to establishing a set amortization period for the deferred income taxes, PNG submits that they do not believe that the application of a set amortization period will result in material benefits (Exhibit B-9, BCUC 2.62.1).

PNG considers that a longer amortization period could result in intergenerational issues "...with customers on the system during the amortization period getting the benefits but customers on the system following the amortization incurring higher rates due to the higher rate base" (Exhibit B-9, BCUC 2.62.2).

Commission Panel Determination

The Panel approves PNG's proposal to draw down $1.2 million of deferred income taxes as a credit to the income tax component of the Test Year 2013 cost of service.

Beyond 2013, the Panel considered whether to establish a set amortization period for the deferred income taxes. The Panel agrees with PNG that only customers on the system during the amortization period will receive the benefits associated with the deferred income taxes. However, in the view of the Panel, a longer amortization period increases intergenerational equity issues, given that the balance relates to historical deferred income tax expenses prior to 1986. Accordingly, the Panel concludes that there should be certainty regarding the timing of the refund of deferred income taxes to ratepayers.

As noted above, the Commission directed PNG in the Pension Decision to amortize $2.525 million of the deferred income tax balance on a consolidated basis over six years, commencing January 1, 2013, to offset the amortization of the NPPRB Regulatory Asset Deferral Account. Excluding the impact of the amortization of the PNG West deferred income tax balance in accordance with the Pension Decision, the Panel expects that the remaining deferred income tax balance at December 31, 2013, would be approximately $7.7 million (i.e. $8.9 million at December 31, 2012, less $1.2 million amortization in 2013). However, a portion of this remaining balance will be amortized in accordance with the Pension Decision. Thus, considering the remaining deferred income tax balance and the approved amortization amounts of $1 million in 2012 and $1.2 million in 2013, the Panel does not anticipate that a five year amortization period for the remaining deferred income tax balance would have a significant impact on PNG's financial health by putting pressure on the Company's cash flows.

Commencing January 1, 2014, PNG is directed to fully amortize the deferred income balance on a straight-line basis over a period of five years.

6.4 Deferral Accounts

PNG is seeking a number of approvals relating to its existing deferral accounts. These are summarized in Exhibit B-1, pages 20 to 25 with updates summarized in Exhibit B-1-1, pages 7 and 8. Additionally, information on the Continuity of Deferred Charges is provided in Exhibit B-1-1, Tab 2, pages 13 to 15.

There are two important issues which must be considered in determining whether to approve the deferral accounts as proposed by PNG: (1) the Appropriate Length of Amortization Period, and (2) the Appropriate Financing Charge.

In the FortisBC Inc. 2012-2013 RRA Decision (FortisBC Decision),[3] the Commission established key principles for the treatment of deferral accounts. Excerpts from the FortisBC Decision which outlined the principles were provided as part of BCUC IR 1.52 (Exhibit B-3). These principles with application to this proceeding are summarized as follows:

(a) When determining the length of an amortization period for a deferral account, the key factors to consider are the benefits of rate smoothing, the length of time where there is direct value related to the item being amortized, and the increased costs that longer amortization periods impose on ratepayers due to the accumulation of financing charges.
(b) Deferral accounts are regulatory assets, not true capital assets; therefore, it is more appropriate for deferral accounts for non-capital items to earn an interest rate of return, not a rate base rate of return.
(c) For deferral accounts for non-capital items which are amortized beyond one year, the appropriate return is the utility's Weighted Average Cost of Debt (WACD). For deferral

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[3] In the Matter of FortisBC Inc. - Application for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan – Commission Order G-110-12 August 15, 2012

accounts for non-capital items which are amortized over a period of one year or less, the appropriate return is the utility's short term interest cost.

(d) For deferral accounts related to capital, the appropriate return is the utility's Weighted Average Cost of Capital (WACC) [Order G-110-12, pp. 104-106].

The Commission Panel finds it appropriate to apply these principles to PNG's deferral accounts. The Panel will address the issues of amortization periods and financing costs separately. Specific attention will be paid to the existing deferral accounts which are not in line with the principles established in the FortisBC Decision.

Amortization Period

PNG currently has four deferral accounts with amortization periods greater than 3 years: (i) Plant Gains and Losses, (ii) Line Break Costs, (iii) Investigative Digs, and (iv) Propane Air Plant (Exhibit B-3, BCUC 1.52.1).

(i) Plant Gains and Losses

This account covers the loss or gain when an asset is retired. A five-year amortization period for the Plants Gains and Losses deferral account was established by the Commission in the Decision 2012. PNG states that the Commission determined that this amortization period represented an acceptable balance between rate smoothing and cost to ratepayers (Exhibit B-3, BCUC 1.52.1; BCUC 1.52.1.4).

(ii) Line Break Costs

The Line Break Costs include the cost of temporary repairs to transmission lines that are not covered by insurance. The deferral account amortization period is ten years. PNG states that historically the temporary repair costs included in this deferral account have been significant; thus, the Commission determined that rate smoothing was the critical determining factor when it established the amortization period (Exhibit B-3, BCUC 1.52.1; BCUC 1.52.1.4).

The 2012 ending balance in the Line Break Costs deferral account is $492,000 and the 2012 addition to the deferral account is $71,000. Gross amortization for 2012 for this deferral account was $171,000, and PNG is requesting approval for an amortization expense for 2013 of $151,000 (Exhibit B-1-1, Tab 2, pp. 13-14). PNG attributes the lower amortization cost for 2013 to the fact that the Copper River Temp repair costs were fully amortized in 2012 (Exhibit B-1, p. 21).

(iii) Investigative Digs

The Investigative Digs deferral account is more unique in that the amortization rate is based on a 10 percent declining balance (Exhibit B-3, BCUC 1.52.1.4). The forecast additions to the deferral account in 2013 represent PNG's budgeted investigative digs based on a review of expected requirements. The actual cost of digs is then recorded in the deferral account at the end of the year. The 2012 cost of investigative digs included in the deferral account is $318,000 (Exhibit B-1, p. 22; Exhibit B-1-1, Tab 2, p. 13). PNG states that investigative digs are normally planned work as a result of pipeline in-line inspections completed the previous year, though unplanned investigative digs can occur as a result of leak detection surveys or other data gathering processes (Exhibit B-9, BCUC 2.53.1).

(iv) Propane Air Plant

The Propane Air Plant deferral account currently has a ten-year amortization period, which was agreed upon during the 2005 Decision. PNG submits that these assets are retired and the relatively long amortization period is countered by the fact that this deferral account only earns a short-term interest rate of return (Exhibit B-3, BCUC 1.52.1.4).

An additional issue is the amortization of the Rate Stabilization Adjustment Mechanism (RSAM). PNG has requested approval to change the amortization period of the RSAM deferral account from a one-year period to a two-year period. (Exhibit B-1, p. 60) While PNG confirms that US GAAP allows for any amortization period to be set which falls within the range of zero to twenty-four months, PNG submits that twenty-four months, or two years, provides the most benefit to ratepayers as it allows for rate smoothing (Exhibit B-3: BCUC 1.8.2, BCUC 1.52.1.4).

Deferral Account Financing Costs

PNG currently has five deferral accounts which are included in rate base and are earning a return based on PNG's Weighted Average Cost of Capital (WACC). The five rate base deferral accounts are as follows: (i) Plants Gains and Losses, (ii) Line Break Costs, (iii) Investigative Digs, (iv) RSAM, and (v) IFRS/US GAAP.

PNG submits that it is appropriate for these accounts to be included in rate base because PNG would be unable to obtain 100 percent debt financing for these long-term regulatory assets (Exhibit B-3, BCUC 1.52.1.1).

Commission Determination

As stated above, the Commission Panel finds it appropriate to apply the principles of the FortisBC Decision to PNG's deferral accounts. With respect to the issue of whether to include non-capital items in rate base there are two issues:

- the appropriate compensation for deferred non-capital items; and
- the appropriate amortization period for deferred non-capital items.

There is a distinction between non-capital items and capital assets which are allowed in rate base: capital assets refer to tangible investments upon which the utility has a right to a return; non-capital items, while regulatory assets, are deferred costs or expenses which would be an expense in the year in which they occur were it not for the use of regulatory deferral accounts. In the view of the Panel, the act of deferring such operational costs for a reasonable time period does not equate to their earning a return commensurate with a capital asset. Such deferred expenses should more appropriately draw an amount in recognition of the amounts expended but not yet collected from ratepayers. The Commission Panel considers the WACD as appropriate proxy compensation for such deferred amounts as it represents the cost of borrowing which is, in effect, what the ratepayer is doing.

This raises the question as to whether deferral accounts for non-capital items should be carried for indefinite periods at the WACD. The Commission Panel concedes that there should be a limit on the amount of time a utility should be restricted to the WACD on a deferred expense. Amounts amortized for periods greater than 5 years are excessive and more appropriately qualify for a rate base rate of return. Accordingly, the Panel accepts that it is appropriate for non-capital expenses deferred for periods of greater than 5 years be granted a full WACC return.

Accordingly, the Commission Panel makes the following determinations with respect to existing deferral accounts:

(i) Plants Gains and Losses

Plants Gains and Losses is an account which deals with capital expenditures that are no longer in use. **Because these expenditures were originally a capital expense and are not fully amortized, the Commission Panel finds that it is appropriate to earn the WACC on this deferral account. The Plants Gains and Losses deferral account is therefore approved to remain in rate base. The Panel also finds the five-year amortization period, as approved in the Decision 2012, to be appropriate.**

(ii) Line Break Costs

The Commission Panel acknowledges that the rationale for establishing the ten-year amortization period for the Line Break Costs deferral account was to create rate smoothing due to the historically high additions to this account. However, in recent years, we note that the additions to this deferral account have been relatively small. As such, the Panel considers that the more relevant consideration going forward is to address the issue of intergenerational equity. The lengthy ten-year amortization period currently in place is no longer necessary and is contrary to the principle of intergenerational equity. A more appropriate amortization period for the Line Break Costs deferral account is three years. In our view, this reduced amortization period addresses intergenerational equity but balances it against an appropriate level of rate smoothing. **The Commission Panel directs PNG to utilize a three-year amortization period for the Line Break Costs deferral account. The Panel directs PNG to re-calculate the 2013 amortization expense based on the new amortization period of three years.**

As noted, line break costs are temporary repairs which normally would be expensed at the time incurred. As noted by PNG in its response to BCUC IR 1.52.1.4 (Exhibit B-3), such costs would not be considered capital under US GAAP. Given the previous discussion, line break costs are deferred non-capital assets which should appropriately earn an interest return based on the WACD. **The Panel directs PNG to remove the Line Break Costs deferral account from rate base and to record an interest return at PNG's WACD.**

(iii) Investigative Digs

The first question to be addressed is whether the use of a deferral account is appropriate for investigative digs or whether these costs are an expense which should be reflected in cost of service as they are incurred. The answer to this question leads to further questions which must be addressed.

<u>Is the use of a deferral account appropriate?</u>

The Commission Panel has determined that the current handling of a deferral account for investigative digs is not appropriate. Investigative digs are not a capital program but are part of the ongoing operational pipeline maintenance program. PNG acknowledges that "...investigative digs are normally planned work as a result of pipeline in-line inspections completed the previous year" (Exhibit B-9, BCUC 2.53.1). It therefore can be inferred that future costs can be estimated with a degree of confidence notwithstanding the potential for additional requirements due to unplanned circumstance. **The Panel directs PNG to record its forecast for investigative digs in its cost of service starting in the 2013 test year.**

<u>What is an appropriate forecast for 2013 and how should variances be handled?</u>

In its response to BCUC IR 1.45.1, PNG stated that 260 investigative digs are planned for 2013 at an estimated cost per dig of $1,460 for a total cost of $380,000. **The Panel finds PNG's forecast cost for investigative digs of $380,000, as stated in BCUC IR 1.45.1, to be reasonable given the actual cost incurred for investigative digs in 2012 and the expected increase in the number of digs and the increase in cost per dig. The Panel directs PNG to record $380,000 for investigative digs in its 2013 cost of service. The Panel is not persuaded there is sufficient evidence to support an increase to $510,000 as outlined in Exhibit B-1-1, Tab 2, pp. 13-14.**

The Commission Panel accepts that there is a potential for significant variances due to unforeseen circumstances. To minimize the impact of these variances, PNG is directed to establish a new Investigative Digs Deferral Account commencing in the Test Year 2013. This new deferral account will be used to record variances between the forecast cost for investigative digs included in PNG's cost of service and the actual costs incurred in the corresponding test year. **The Panel finds the most appropriate amortization period for this new deferral account to be one year given that variances should be relatively small in a given year**. **The Panel further directs PNG to setup the new deferral account as non-rate base attracting an interest return at PNG's short term interest rate.** This financing treatment is consistent with PNG's other deferral accounts with one-year amortization periods and is consistent with the principles of the FortisBC Decision.

<u>Handling of 2012 Deferral Account Ending Balance:</u>

The Commission Panel directs PNG to amortize the ending 2012 balance in the Investigative Digs Deferral Account with carrying costs reflecting the WACD into rates over a 5 year period. The ending 2012 balance in the Investigative Digs Deferral Account is $973,000 (Exhibit B-1-1, Tab 2, p. 13). A five year amortization period will result in a higher amortization expense in the 2013 test year than the amount proposed by PNG in the Application; however, we are of the view that this amortization period is appropriate because it addresses issues related to intergenerational equity while still providing rate smoothing. The use of WACD for carrying costs is consistent with the handling of expense-related deferral accounts and the principles established in the FortisBC Decision.

(iv) Rate Stabilization Adjustment Mechanism

The Commission Panel approves PNG's request to change the amortization period of the RSAM to two years. This provides rate-smoothing benefits to customers while still maintaining PNG's compliance with US GAAP Revenue Recognition criteria. The Panel also approves the RSAM rate rider of $(0.269)/GJ for the test year 2013.

The Panel directs PNG to remove the RSAM from rate base and to record an interest return on this account at PNG's WACD. This treatment is consistent with the handling of expense-related deferral accounts and the principles established in the FortisBC Decision.

(v) IFRS/US GAAP

The Panel accepts the currently approved amortization period for the IFRS/US GAAP deferral account as appropriate.

The Panel directs PNG to remove the IFRS/US GAAP deferral account from rate base and to record an interest return on this account at PNG's WACD. This treatment is consistent with the handling of expense-related deferral accounts and the principles established in the FortisBC Decision.

The Commission Panel expects that in the future PNG will apply the principles established in the FortisBC Inc. 2012-2013 RRA Decision when applying for the establishment of future deferral accounts. **Notwithstanding determinations with respect to the specific deferral accounts discussed above, the Commission Panel approves the changes to PNG's remaining deferral accounts applied as for in the 2013 test year.**

6.5 Computer Equipment Replacement and Upgrade Policy

In compliance with a Decision 2012 directive, PNG filed a formal "Computer Equipment Upgrade and Replacement Policy" in the Application. **The Panel reviewed the "Computer Equipment Upgrade and Replacement Policy" and finds that the policy is reasonable.**

6.6 Budget Billing Program

The cash working capital balance included in PNG's rate base is offset by a "Budget Billing Plan" adjustment. PNG's submits that: "[t]he Budget Billing Plan allows customers to pay their estimated annual gas use and charges over 11 months of equal installments. This plan is provided to help customers manage their payments and cash flow more easily. It is available to any PNG residential or commercial customer whose account is in good standing" (Exhibit B-3, BCUC 1.10.1).

The following schedule summarizes the difference between the Actual Budget Billing Plan balance reported by PNG and the Decision approved balance over the past three years:

Table 3

Budget Billing Plan Adjustment	**Test Year 2013**	**2012**	**2011**	**2010**
	($000s)			
Forecast (Decision)	(900)	(725)	(233)	(257)
Actual		(1,630)	(1,667)	(1,603)
Difference		**905**	**1,434**	**1,346**

(Exhibit B-9, BCUC 2.4.1)

The Budget Billing Plan balance is an offsetting adjustment to the cash working capital balance included in rate base. Therefore, when the Budget Billing Plan balance is understated, rate base and the return on rate base are both overstated.

PNG submits that the historical differences between the actual balance reported by PNG and the approved balance are due to issues with the data that PNG has used for its historical actual Budget Billing Plan balance. Specifically, PNG uses the average month-end payable Budget Billing Plan balance from PNG's general ledger for its historical actual balance, which results in several cumulative errors. PNG notes that they are uncertain that their billing system can present the data required to adjust the historical actual balances to address the cumulative errors resulting from using the average month-end payable Budget Billing Plan balance. Accordingly, PNG submits the following proposal:

> "...PNG proposes using a three-year running average, 2010 thru 2012, of its historical 'actuals' for its 2013 test year provision for the budget billing plan adjustment to cash working capital. PNG would also propose to continue use of the three-year running average of historical actuals until such time as it can demonstrate the veracity of its test year calculation methodology for the budget billing balance..." (Exhibit B-9, BCUC 2.4.2).

Commission Determination

The Panel agrees with PNG that in the absence of an accurate measure of the forecast Budget Billing Plan balance compared to the reported historical actual balances, using a three-year running average (i.e. 2010 – 2012) of the historic actual balances reported by PNG for the 2013 test year balance is appropriate.

The Commission Panel directs PNG to use a Budget Billing Plan adjustment to cash working capital of $1.633 million in test year 2013. In addition, PNG is directed to use a three year running average of the historical actual amounts to determine the forecast Budget Billing Plan adjustment until such time as the accuracy of the calculation can be demonstrated.

6.7 Negative Salvage Accounting

In the 2012 PNG RRA Decision, the Commission directed PNG to provide an analysis of the potential use of negative salvage accounting (2012 PNG RRA Decision, p. 46).

PNG states that that the costs of asset retirements are not significant enough to justify the additional administration time and cost associated with implementing negative salvage accounting and that its fixed assets system does not have the capability to handle negative salvage rates. PNG also states that it is satisfied with its handling of asset retirements, which was approved in the 2012 PNG RRA Decision, but it will include a review of negative salvage value rates in its next Depreciation Study (Exhibit B-1, p. 67; Exhibit B-3, BCUC 1.53.3).

Commission Determination

The Commission Panel accepts that it continues to be appropriate for PNG to record the costs of asset retirements in the ordinary course of business to the Plant Gains and Losses deferral account as they are incurred. However, the Panel is supportive of PNG's decision to include an evaluation of the potential of using negative salvage accounting in its next Depreciation Study. Our expectation is that this evaluation will include a thorough examination of the pros and cons of utilizing negative salvage accounting and the costs of its implementation.

7.0 OTHER

7.1 The Appropriateness of the AltaGas Allocation

AltaGas has changed its methodology for allocating corporate service costs to its subsidiaries. Starting in 2013, AltaGas is now using the Modified Massachusetts Formula (MMF). Based on the MMF, AltaGas has allocated an inter-affiliate service charge of $1.6 million to PNG. While PNG has not proposed to recover this amount for the 2013 test year, there is a large gap between the AltaGas allocation of inter-affiliate charges and the charges of $621,312 that the Panel approved (see section 4.3.1). While this issue is not integral to the Panel's decision respecting inter-affiliate charges, it will have important consequences for future decisions and requires some attention. As previously noted, PNG "expects to seek recovery of all costs allocated by its parent company" (Exhibit B-1, pp. 11-13), in future years, as PNG's economic circumstances improve.

There are two aspects to the overall appropriateness of the AltaGas allocation of corporate service costs to PNG: the cost pool and the percentage allocator applied to the cost pool. PNG stated that AltaGas' 2013 forecast costs are $25.880 million. Based on the MMF, 6.26 percent of this cost pool is allocated to PNG (Exhibit B-3, BCUC 1.22.3). When asked in BCUC IR 2.39.1 how PNG gained comfort over the reliability of the $25.9 million cost pool, PNG responded that it does not have access to AltaGas budgets nor would it have the level of knowledge necessary, even if it had access to the detailed budget, to perform a meaningful assessment of the cost pool. However, PNG also states AltaGas has proposed to limit the expected inter-affiliate costs to fixed and common costs for 2013 that will benefit PNG and ratepayers, in the allocation to PNG (Exhibit B-9, BCUC 2.39.2, p. 55).

BCPSO submits that there has been no meaningful discovery of AltaGas' corporate expenses in this proceeding. Moreover, BCPSO submits that there is insufficient evidence to approve the adequacy of the cost pool. Further, they note PNG's admission that AltaGas' MMF methodology has not yet passed the scrutiny of the Alberta Utilities Commission (Exhibit B-3, BCUC 1.22.7) and that PNG had no external reports to support the efficacy of the MMF (Exhibit B-3, BCUC 1.22.8). Regardless, BCPSO contends that any allocation of inter-affiliate costs ought not to exceed the calculation of standalone costs.

In its Reply Submission, PNG notes that it has provided a breakdown of the AltaGas costs and that the cost pools used to allocate services to PNG are the same cost pools used to allocate corporate service costs to all of the AltaGas affiliates, to ensure there is no cross-subsidization.

Commission Determination

The Panel determines that it is unnecessary to consider the AltaGas MMF methodology for the 2013 test year and in any case, there is insufficient evidence to consider the matter further in this proceeding.

7.2 Reconciliation of US versus Canadian GAAP

On January 1, 2012, International Financial Reporting Standards (IFRS) replaced Canadian GAAP for all Canadian Publicly Accountable Enterprises. PNG received Commission approval to adopt US GAAP for regulatory accounting and reporting purposes for the period January 1, 2012 to December 31, 2014, by way of Order G-168-11. The Order directed PNG to prepare a reconciliation of amounts reported for regulatory accounting under US GAAP and 2011 Canadian GAAP for the year ending December 31, 2012, and stated that: "[t]he requirement to provide reconciliation in further periods should be addressed as part of the 2012 RRA."

PNG requested relief in the 2012 RRA from filing further period reconciliations between US GAAP and 2011 Canadian GAAP and US GAAP, as directed by Order G-168-11. By way of Order G-130-12, the Commission denied PNG's request.

In the 2013 RRA, PNG filed the reconciliation between US GAAP and 2011 Canadian GAAP regulatory accounting amounts for the consolidated year ended December 31, 2012 results (Exhibit B-1-2). PNG submits that there are no material income statement differences between the two GAAPs, as the summary working paper shows the difference between the two GAAPs is $9,000 for pension expense and $21,000 for NPPRB. PNG requests that no further period reconciliations be required in the future. If it is not required to provide the calculation of pension and NPPRB expenses under 2011 Canadian GAAP, PNG would expect to reduce its annual actuarial costs in its cost of service (Exhibit B-1-2, p. 1).

The Panel has reviewed the reconciliation provided by PNG and notes that the net difference between the two GAAPs on a consolidated basis is $12,000.

Commission Determination

Based on the reconciliation provided by PNG, the Panel concludes that the net difference between the two GAAPs on a consolidated basis is not significant. The Panel notes that PNG will not return to reporting in accordance with 2011 Canadian GAAP for external financial and regulatory purposes in the future. **For these reasons, the Panel approves PNG's request for relief from providing future period reconciliations for amounts reported for regulatory accounting under US GAAP and 2011 Canadian GAAP. In the next RRA, PNG is directed to identify the reduction in annual actuarial costs achieved given that PNG is no longer required to provide the calculation of pension and NPPRB expenses under 2011 Canadian GAAP.**

7.3 Replacement of Revolving Debt Facility

PNG submits that it will "...seek to renegotiate, extend or replace the existing 5-year revolving debt facility early in 2013, or as market conditions allow" (Exhibit B-1, p. 45). Accordingly, the calculation of return on rate base included in the 2013 Cost of Service incorporates the initial indicative terms of the new facility obtained from one PNG's current facility providers.

On May 6, 2013, PNG applied to the Commission for approval to enter into a committed five year term revolving debt facility with its parent company, AltaGas. By Order G-82-13 dated May 23, 2013, the Commission approved the request.

Commission Determination

The Panel has reviewed the term sheet for the AltaGas debt facility approved by Order G-82-13 against the indicative terms used to calculate the return on rate base included in the 2013 cost of service.

The Panel does not consider the differences between the two term sheets to be significant. In addition, the indicative terms have been tested through evidence in this proceeding. **Accordingly, the Panel approves the use of the indicative terms to calculate the return on rate base included in the 2013 test year cost of service.**

7.4 Proposed Cost of Capital Changes

PNG acknowledges that the return on common equity and capital structure will be determined in Stage 2 of the Generic Cost of Capital (GCOC) proceeding. However, in preparing this Application, PNG has used a common equity thickness of 46.5 percent, which is 1.5 percent above the 2012 approved common equity thickness of 45 percent. The impact of this increase in equity thickness is to increase the revenue requirement by $208,000. In Decision 2012 a similar request was not approved; however, the Panel in the 2012 proceeding allowed PNG to record the revenue requirement effect of the proposed increase in a non-rate base deferral account with interest calculated at the WACD. The disposition of this account is to be determined in the RRA proceeding following the issuance of the Stage 2 GCOC decision (Exhibit B-1, p. 43; Exhibit B-9, BCUC 2.11.0).

Commission Determination

Order G-187-12 related to Stage 1 of the 2012 GCOC proceeding issued on December 10, 2012, addressed this issue as follows:

> "The current ROE [Return on Equity] and capital structure for all regulated utilities in B.C. that rely on the benchmark utility to establish Rates are to be maintained and made interim, effective January 1, 2013"; and
>
> "Any determinations of the premiums on the benchmark ROE and Capital structure of regulated utilities that depend on the benchmark utility for rate setting will be made following the decisions made in Stage 2."

The Commission Panel sees no reason to vary Order G-187-12 and directs PNG West to calculate its 2013 return on equity using the approved 2012 common equity thickness of 45 percent. No further amounts beyond December 31, 2012 are to be recorded in the non-rate base deferral account which was approved for use in 2012.

7.5 Parent Reporting Requirements – Executive Time

In the Decision 2012, PNG was directed to provide a comparison of expected versus actual time spent on AltaGas regulatory and reporting requirements in its next revenue requirements. PNG notes that the Decision 2012 was issued in September 2012 and previously, this information had not been tracked. Given the timing of the Decision PNG proposes to track executive's time for a period spanning October 1, 2012 to September 30, 2013 and report on it in the 2014 RRA. (Exhibit B-1, Application, p. 65)

Commission Determination

The Commission Panel agrees that the timing proposed by PNG for the tracking of executive time on parent company reporting and regulatory requirements is reasonable and approves it.

7.6 Unaccounted for Gas

In the 2008 PNG RRA proceeding,[4] the Commission allowed PNG to record Unaccounted for Gas (UAF) losses above 0.7 percent in the UAF volume deferral account without further approval from the Commission. (Order G-165-07, NSA 2008, Item 11) In response to the 0.93 percent variance in 2008, the Commission accepted PNG's request in the 2009 PNG RRA[5] proceeding to increase the band and approved PNG to record a loss of up to 1.0 percent in the UAF volume deferral account without seeking further Commission approval (Order G-39-09, 2009 NSA, Item 14).

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[4] In the Matter of Pacific Northern Gas an Application for Approval of 2008 Revenue Requirements and Rates (PNG-West and Granisle) – Commission Order G-165-07, December 19, 2007.
[5] In the Matter of Pacific Northern Gas an Application for Approval of its 2009 Revenue Requirements for the PNG-West Service Area, Commission Order G-39-09, April 23, 2009.

In the Application, PNG did not request changes to the Commission decision made in Order G-39-09 nor has anything come to the Panel's attention that would cause it to make a change to this decision. The Commission Panel will continue to allow an UAF volume variance of up to 1.0 percent from forecast in the UAF volume deferral account and requires PNG to file an application with the Commission for recovery on UAF losses above 1.0 percent.

7.7 Future RRAs

As noted in Section 2.3, the preparation of an RRA and the process leading to reaching a decision is both time consuming and expensive. There were a number of instances within the Application where the information provided by PNG was incomplete (some of these have been addressed within this Decision). This necessitated additional IRs which might have been avoided. **To ensure a more efficient process, the Panel directs PNG in future RRA's to include the following information:**

- **Working excel model of all regulatory schedules contained in the RRA, in electronic format.**
- **Historical actual customer load data.**
- **More detailed narrative explaining the changes made in the Updated Application.**

8.0 SUMMARY OF COMMISSION DECISION DETERMINATIONS

This Summary is provided for the convenience of readers. The content of this directive list is not inclusive of all decisions and determinations made throughout the reasons for decision. Where directives are listed below, additional context may be provided through the reasons for decision. Where any discrepancy or confusion may arise due to lack of context, the determinations made within the reasons for decision shall prevail.

No.	Directive	Page
1.	The Commission Panel directs PNG to file its 2014 RRA for a two year period.	10
2.	The Commission Panel directs PNG to remove Conifex from the ICDDA and treat Conifex as a Small Industrial customer for 2013 and onwards.	15
3.	Consistent with the PNG(N.E.) Resource Plan order, the Commission Panel directs PNG to consider section 44.1 (2) of the UCA and DSM when filing its 2013 Resource Plan.	17
4.	The Commission Panel denies the $180,000 requested by PNG for the two additional positions.	20
5.	The Commission Panel finds that the proposed salary increase is not unreasonable given the size of increase and the amount approved in the Decision 2012. The 3 percent salary increase costing $65,000 is approved as it falls within a reasonable range for salary increases.	21
6.	The Commission Panel denies the inclusion of the $98,000 for [the MTIP] program in rates.	21
7.	The Commission Panel approves a total of $2.576 million in Administrative and General wages which is a reduction of $278,000 from the amount proposed by PNG.	21
8.	The Panel directs PNG to reduce its 2013 forecast for Educational Expense and Employee Service Award programs by an amount totalling $15,000.	24
9.	The Panel directs PNG to recalculate this amount and any amounts related to the 1 percent increase in the non-union and executive groups are to be charged to the account of the shareholder.	24
10.	The Panel approves the forecast amount of $2.809 million for pension and NPPRB costs for the 2013 test period.	26
11.	The Commission Panel directs PNG to provide a detailed justification of pension and NPPRB as part of its next RRA.	26
12.	PNG is directed to reduce overall employee benefits cost by $15,000 plus any amounts related to the 1 percent reduction of the amount proposed for the employee savings plan for non-union and executive management employees.	26

13.	The Commission Panel denies PNG's claim for recovery of $750,000 in the cost of service for inter-affiliate charges. The Panel finds that $621,312 is appropriate and reasonable for the total inter-affiliate charges.	30
14.	Consistent with the Decision 2012 treatment of donations expense, the corporate sponsorship budget of $41,000 is to be shared equally between the shareholder and the ratepayer.	32
15.	The Commission Panel has reviewed the explanation provided by PNG of the government relations program. Except the comments regarding the corporate sponsorship expense, the Panel finds the explanation provided reasonable.	32
16.	The Commission Panel reviewed the KPMG report provided in Tab 6 of the Application and finds that KPMG's evaluation of the appropriateness of the revised shared services methodology is thorough.	34
17.	The Panel accepts PNG's conclusion that the creation of a standalone Customer Care Centre in the PNG(N.E.) service territory is not supportable economically at this time.	35
18.	The Commission Panel approves the cost pools and the cost allocators as proposed in the 2012 Shared Services Study and as set forth in the Application. The Commission Panel approves the level of shared service cost recovery by PNG from PNG(N.E.) for the 2013 test year subject to the changes required to be made to PNG's Administrative and General Expenses as directed by the Panel in this Decision as well as those outlined in responses to IRs.	35
19.	The Commission Panel reviewed the evidence and given the modest 2 percent forecast increase finds the 2013 forecast cost of service for Operating and Maintenance expenses of $9.418 million to be fair, just and reasonable.	37
20.	The Panel denies the $887,000 capital additions for the Rio Tinto Alcan modernization project for 2013. The Panel directs PNG to place the costs incurred for the RTA project in the test year 2013 into a non-rate base, non-interest bearing deferral account. PNG is directed to apply for approval of the capital costs associated with the RTA project as part of its 2014 RRA.	40
21.	The Commission Panel approves the capital expenditures of $3.337 million as outlined in Table 1 with the exception of downward adjustments of $887,000 for the RTA modernization project and $75,000 for mobile equipment.	40

22.	The Commission Panel directs PNG to provide the completed Schedule 1 report (as outlined in IR 1.66.1) on 2013 capital additions as part of its next RRA as well as an update on 2012 capital additions detailing any further variances. In addition, any project with a variance in excess of $25,000 is to be accompanied by an explanation detailing the reason for the variance.	41
23.	The Panel approves PNG's proposal to draw down $1.2 million of deferred income taxes as a credit to the income tax component of the Test Year 2013 cost of service.	43
24.	Commencing January 1, 2014, PNG is directed to fully amortize the deferred income balance on a straight-line basis over a period of five years.	44
25.	Because these expenditures were originally a capital expense and are not fully amortized, the Commission Panel finds that it is appropriate to earn the WACC on this deferral account. The Plants Gains and Losses deferral account is therefore approved to remain in rate base. The Panel also finds the five-year amortization period, as approved in the Decision 2012, to be appropriate.	48
26.	The Commission Panel directs PNG to utilize a three-year amortization period for the Line Break Costs deferral account. The Panel directs PNG to re-calculate the 2013 amortization expense based on the new amortization period of three years.	48
27.	The Panel directs PNG to remove the Line Break Costs deferral account from rate base and to record an interest return at PNG's WACD.	49
28.	The Commission Panel has determined that the current handling of a deferral account for investigative digs is not appropriate.	49
29.	The Panel directs PNG to record its forecast for investigative digs in its cost of service starting in the 2013 test year.	49
30.	The Panel finds PNG's forecast cost for investigative digs of $380,000, as stated in BCUC IR 1.45.1, to be reasonable given the actual cost incurred for investigative digs in 2012 and the expected increase in the number of digs and the increase in cost per dig. The Panel directs PNG to record $380,000 for investigative digs in its 2013 cost of service. The Panel is not persuaded there is sufficient evidence to support an increase to $510,000 as outlined in Exhibit B-1-1, Tab 2, pp. 13-14.	49
31.	The Panel finds the most appropriate amortization period for this new [Investigative Digs] deferral account to be one year given that variances should be relatively small in a given year. The Panel further directs PNG to setup the new deferral account as non-rate base attracting an interest return at PNG's short term interest rate.	50
32.	The Commission Panel directs PNG to amortize the ending 2012 balance in the Investigative Digs deferral account with carrying costs reflecting the WACD into rates over a 5 year period.	50
33.	The Commission Panel approves PNG's request to change the amortization period of the RSAM to two years. This provides rate-smoothing benefits to customers while still maintaining PNG's compliance with US GAAP Revenue Recognition criteria. The Panel also approves the RSAM rate rider of $(0.269)/GJ for the test year 2013.	50
34.	The Panel directs PNG to remove the RSAM from rate base and to record an interest return on this account at PNG's WACD.	50

35.	The Panel directs PNG to remove the IFRS/US GAAP deferral account from rate base and to record an interest return on this account at PNG's WACD.	51
36.	Notwithstanding determinations with respect to the specific deferral accounts discussed above, the Commission Panel approves the changes to PNG's remaining deferral accounts applied as for in the 2013 test year.	51
37.	The Panel reviewed the "Computer Equipment Upgrade and Replacement Policy" and finds that the policy is reasonable.	51
38.	The Commission Panel directs PNG to use a Budget Billing Plan adjustment to cash working capital of $1.633 million in test year 2013. In addition, PNG is directed to use a three year running average of the historical actual amounts to determine the forecast Budget Billing Plan adjustment until such time as the accuracy of the calculation can be demonstrated.	53
39.	The Panel determines that it is unnecessary to consider the AltaGas MMF methodology for the 2013 test year and in any case, there is insufficient evidence to consider the matter further in this proceeding.	55
40.	The Panel approves PNG's request for relief from providing future period reconciliations for amounts reported for regulatory accounting under US GAAP and 2011 Canadian GAAP. In the next RRA, PNG is directed to identify the reduction in annual actuarial costs achieved given that PNG is no longer required to provide the calculation of pension and NPPRB expenses under 2011 Canadian GAAP.	56
41.	The Panel approves the use of the indicative terms to calculate the return on rate base included in the 2013 test year cost of service.	57
42.	The Commission Panel sees no reason to vary Order G-187-12 and directs PNG West to calculate its 2013 return on equity using the approved 2012 common equity thickness of 45 percent. No further amounts beyond December 31, 2012 are to be recorded in the non-rate base deferral account which was approved for use in 2012.	58
43.	The Commission Panel agrees that the timing proposed by PNG for the tracking of executive time on parent company reporting and regulatory requirements is reasonable and approves it.	58
44.	To ensure a more efficient process, the Panel directs PNG in future RRA's to include the following information: • Working excel model of all regulatory schedules contained in the RRA, in electronic format. • Historical actual customer load data. • More detailed narrative explaining the changes made in the Updated Application.	59

DATED at the City of Vancouver, in the Province of British Columbia, this 1st day of August 2013.

Original signed by:

____

D.A. COTE
PANEL CHAIR/COMMISSIONER

Original signed by:

____

C.A. BROWN
COMMISSIONER

Original signed by:

____

C. VAN WERMESKERKEN
COMMISSIONER

ORDERS SOUGHT

PNG is seeking the following Commission approvals under this Application:

1. Approval pursuant to sections 59 to 61 of the Act, of the 2013 revenue deficiency of approximately $454 thousand, as filed in the schedules accompanying PNG's Application.
2. Approval of recovery of the AltaGas Ltd. service charge to PNG for 2013 of $750,000 in the cost of service.
3. Approval of the cost pools, the cost allocators and level of shared service cost recovery by PNG from PNG(N.E.), as proposed in the 2012 Shared Services Study and as set forth in this Application for 2013, for the purposes of determining the level of such costs to be recovered by PNG(N.E.) in its customer rates.
4. Approval of the changes to PNG's deferral accounts as detailed earlier in this Application under the heading "Amortization" and as shown in the Continuity of Deferred Charges tables set forth under Tab 2.
5. Approve a two year amortization period for RSAM to ensure compliance with US GAAP Revenue Recognition criteria.
6. Approval to continue the unaccounted for gas ("UAF") volume deferral account on the basis that the UAF volume forecast for test year 2012 is set at zero with PNG recording the variance between zero percent and a loss of up to 1.0 percent without having to seek further Commission approval. PNG would be required to file an application with the Commission to obtain approval to record UAF losses above 1.0 percent in this deferral account.
7. Approval to draw down $1,200,000 of deferred income taxes as a credit to the income tax component of the test year 2013 cost of service.

(Source: Exhibit B-9-1, BCUC 2.80.1)

LIST OF ACRONYMS

AltaGas	AltaGas Ltd.
Application	Pacific Northern Gas Ltd. 2013 Revenue Requirements Application
BC Hydro	British Columbia Hydro and Power Authority
BCPSO	British Columbia Pensioners' and Seniors' Organization et al.
BCUC, Commission	British Columbia Utilities Commission
CIS	Customer Information Services
DC	Dawson Creek
DSM	Demand Side Management
DSUs	Deferred Share Units
FortisBC Decision	FortisBC Inc. 2012-2013 Revenue Requirements Application Decision
FSJ	Fort St. John
GCOC	Generic Cost of Capital
GP	General Plant
IBEW	International Brotherhood of Electrical Workers
ICDDA	Industrial Customers Delivery Deferral Account
IFRS	International Financial Reporting Standards
IR	Information Request
LNG	Liquefied Natural Gas
MMF	Modified Massachusetts Formula
MTIP	Mid Term Incentive Plan
NB	New Business
NGV	Natural Gas Vehicle
NPPRB	Non-Pension Post Retirement Benefits
NSP	Negotiated Settlement Process
O&M	Operating and Maintenance
Pension Application	PNG Consolidate 2012 Pension and Non-Pension Benefits Application
Pension Decision	PNG Consolidate 2012 Pension and Non-Pension Benefits Application Decision
PNG	Pacific Northern Gas Ltd.
PNG West	Pacific Northern Gas Ltd. - West Division
PNG(N.E.)	Pacific Northern Gas (N.E.) Ltd.
PRRD	Peace River Regional District
ROE	Return on Equity

RRA	Revenue Requirements Application
RSAM	Revenue Stabilization Adjustment Mechanism
RTA	Rio Tinto Alcan
SB	System Betterment
TR	Tumbler Ridge
UAF	Unaccounted for Gas
UCA	*Utilities Commission Act*
GAAP	Generally Accepted Accounting Principles
WACC	Weighted Average Cost of Capital
WACD	Weighted Average Cost of Debt
WCB	Workers Compensation

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Pacific Northern Gas Ltd.
West Division 2013 Revenue Requirements Application

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated December 14, 2012 – Commission Order G-192-12 establishing a Preliminary Regulatory Timetable
A-2	Letter Dated January 15, 2013 – Order G-3-13 Amended Preliminary Regulatory Timetable
A-3	Letter Dated January 25, 2013 – Commission Information Request No. 1
A-4	~~CONFIDENTIAL~~ Letter Dated January 25, 2013 – ~~Confidential~~ Commission Information Request No. 1 - confidentiality removed
A-5	Letter Dated February 6, 2013 – Appointment of Panel
A-6	Letter Dated February 15, 2013 – Commission Information Request No. 1 regarding PNG Shared Service Cost Recovery from PNG(N.E.)
A-7	Letter L-9-13 Dated March 1, 2013 – Application Update Filing Extension
A-8	Letter L-12-13 Dated March 7, 2013 – Regulatory Process
A-9	Letter Dated March 15, 2013 – Commission Information Request No. 2
A-10	~~CONFIDENTIAL~~ Letter Dated March 15, 2013 – ~~Confidential~~ Commission Information Request No. 2- confidentiality removed
A-11	Letter Dated March 20, 2013 – Order G-42-13 and Amended Regulatory Timetable
A-12	Letter Dated March 22, 2013 – Commission Information Request No. 2 regarding PNG Shared Service Cost Recovery from PNG(N.E.)
A-13	Letter Dated July 16, 2013 – Commission Notice of Lift of Confidentiality

Exhibit No.	Description
APPLICANT DOCUMENTS	
B-1	**PACIFIC NORTHERN GAS LTD. WEST SERVICE AREA (PNG)** Letter Dated November 30, 2012 – 2013 Revenue Requirements Application
B-1-1	Letter Dated March 4, 2013 – PNG Submitting Updated Application
B-1-2	Letter Dated March 11, 2013 – PNG Filing Outstanding Matters
B-2	~~CONFIDENTIAL~~ Letter Dated January 9, 2013 – PNG Submitting ~~Confidential~~ Customer Load Forecast Data - confidentiality removed
B-2-1	Letter Dated January 14, 2013 – PNG Submitting Request for Confidentiality of Exhibit B-2
B-3	Letter Dated February 15, 2013 – PNG Submitting Response to BCUC Information Request No. 1
B-3-1	Letter Dated February 15, 2013 – PNG Submitting ~~Confidential~~ Response to BCUC Information Request No. 1 - confidentiality removed
B-4	Letter Dated February 15, 2013 – PNG Submitting Response to BCPSO Information Request No. 1
B-5	Letter Dated February 28, 2013 – PNG Requesting Application Update Filing Extension
B-6	Letter Dated March 1, 2013 – PNG Submitting Response to BCPSO IR No. 1 Shared Services Cost Recovery
B-7	Letter Dated March 1, 2013 – PNG Submitting Response to BCUC IR No. 1 Shared Services Cost Recovery
B-8	Letter Dated March 11, 2013 – PNG Filing Comments on BCPSO's submissions
B-9	Letter Dated April 8, 2013 – PNG Submitting Response to BCUC IR No. 2
B-9-1	Letter Dated April 12, 2013 – PNG Filing of outstanding responses to BCUC IR No. 2
B-10	~~CONFIDENTIAL~~ Letter Dated April 8, 2013 – PNG Submitting Response to ~~Confidential~~ BCUC IR No. 2 - confidentiality removed
B-11	Letter Dated April 8, 2013 – PNG Submitting Response to BCPSO IR No. 2

Exhibit No.	Description
B-12	Letter Dated April 12, 2013 – PNG Submitting Response to BCUC IR No. 2 Shared Services Cost Recovery
B-12-1	**CONFIDENTIAL** Letter Dated April 12, 2013 – PNG Submitting Confidential Response to BCUC IR No. 2 Shared Services Cost Recovery
B-13	Letter Dated April 12, 2013 – PNG Submitting Response to BCPSO IR No. 2Shared Services Cost Recovery

INTERVENER DOCUMENTS

C1-1	**BC PENSIONERS' AND SENIORS' ORGANIZATION, ACTIVE SUPPORT AGAINST POVERTY, BC COALITION OF PEOPLE WITH DISABILITIES, COUNSEL OF SENIOR CITIZENS' ORGANIZATIONS OF BC, AND THE TENANT RESOURCE AND ADVISORY CENTRE (BCPSO ET AL)** Letter Dated January 15, 2013 – Request for Intervener Status by James Wightman and Eugene Kung
C1-2	Letter Dated February 1, 2013 – BCPSO Submitting Information Request No. 1
C1-3	Letter Dated February 14, 2013 – BCPSO Submitting Information Request No. 1 on SSCR
C1-4	Letter Dated February 20, 2013 – BCPSO Submissions on Process
C1-5	Letter Dated March 15, 2013 - BCPSO Submitting Information Request No. 2 to PNG
C1-6	BCPSO Information Request No. 2 dated March 22, 2013 on Shared Services Cost Recovery from PNG(N.E.)
C2-1	**PEACE RIVER REGIONAL DISTRICT (PRRD)** Letter Dated January 24, 2013 – Request for Late Intervener Status by Carolyn MacEachern

INTERESTED PARTY DOCUMENTS

D-1	**PEACE RIVER REGIONAL DISTRICT (PRRD)** Letter Dated January 18, 2013 – Changed to Intervener

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-114-13

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Pacific Northern Gas Ltd.
Application for Approval of 2013 Revenue Requirements
for the PNG-West Service Area

BEFORE: D.A. Cote, Panel Chair/Commissioner
C.A. Brown, Commissioner
C. van Wermeskerken, Commissioner

August 1, 2013

O R D E R

WHEREAS:

A. On November 30, 2012, Pacific Northern Gas Ltd. (PNG) filed its 2013 Revenue Requirements Application with the British Columbia Utilities Commission (Commission), pursuant to sections 58 to 61 of the *Utilities Commission Act* (Act) seeking, among other things, approval to increase delivery rates. PNG also sought interim relief, pursuant to sections 58 to 61, 89 and 90 of the Act, to allow PNG to amend its rates on an interim and refundable basis, effective January 1, 2013, pending the hearing of the Application and orders subsequent to that hearing (Application);

B. Commission Order G-192-12, dated December 14, 2012, approved the delivery rates and the Rate Stabilization Adjustment Mechanism (RSAM) rider set forth in the Application on an interim basis, effective January 1, 2013, and established a Preliminary Regulatory Timetable for the review of the Application;

C. Commission G-3-13, dated January 15, 2013, established an Amended Preliminary Regulatory Timetable to allow Interveners and Commission staff sufficient opportunity to review the 2013 Shared Services Cost Allocation to PNG(N.E.) in the context of both the Application and the PNG(N.E.) 2013 RRA;

D. The Peace River Regional District (PRRD) and British Columbia Pensioners' and Seniors Organization et al. (BCPSO) registered as Interveners and BCPSO actively participated in the proceeding;

E. On March 4, 2013, PNG filed an updated Application which forecasts a revenue deficiency of approximately $0.454 million, down from $0.621 million in the original Application (collectively, the Application) which the Commission established by Order G-42-13 would be heard though a written hearing process;

…/2

F. The Commission considered the Application, the evidence and the written arguments as set forth and discussed in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission, for the reasons stated in the Decision issued concurrently with this order, makes the following determinations:

1. Pursuant to sections 59 to 61 of the *Utilities Commission Act*:

    a. The 2013 revenue deficiency of approximately $0.454 million is not approved, as filed.
    b. The 2013 Rate Stabilization Adjustment Mechanism rider of ($0.269)/GJ is approved, as filed.

2. Pacific Northern Gas Ltd. must resubmit its financial schedules incorporating all the adjustments outlined in the Decision, on or before September 3, 2013. The financial schedules must incorporate all of the adjustments identified by Pacific Northern Gas Ltd. in response to Information Requests in this proceeding.

3. The Commission will accept amended Tariff Rate Schedules filed on or before September 3, 2013 which conform to determinations made in the Decision.

4. Pacific Northern Gas Ltd. is to inform all customers of permanent rates by way of written notice included with their next customer invoice.

5. If the 2013 permanent rates, including delivery rates and the Rate Stabilization Adjustment Mechanism rider, are less than the 2013 interim rates, Pacific Northern Gas Ltd. is to refund to customers the difference in revenue with interest at the average prime rate of Pacific Northern Gas Ltd.'s principal bank for its most recent year. If the 2013 permanent rates exceed the 2013 interim rates, Pacific Northern Gas Ltd. is to reflect this difference in customer rates over the balance of 2013.

6. Pacific Northern Gas Ltd. is directed to comply with all other directives in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 1st day of August 2013.

BY ORDER

Original Signed by:

D.A. Cote
Panel Chair/Commissioner