

**PACIFIC NORTHERN GAS LTD.
(PNG-West Division)**

**2012 Revenue Requirements Application
to the
B.C. Utilities Commission**

November 30, 2011



Pacific Northern Gas Ltd.

(PNG-West Division)

2012 REVENUE REQUIREMENTS APPLICATION

November 30, 2011

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**In the Matter of the Utilities
Commission Act, R.S.B.C. 1996,
c. 473, as amended**

- and -

**In the Matter of

PACIFIC NORTHERN GAS LTD.
(PNG-West Division)**

2012 REVENUE REQUIREMENTS APPLICATION

November 30, 2011

**TO: British Columbia Utilities Commission
Sixth Floor
900 Howe Street, P.O. Box 250
Vancouver, B.C.
V6Z 2N3**

PACIFIC NORTHERN GAS LTD. ("PNG") hereby applies to the British Columbia Utilities Commission (the "Commission" or "BCUC") for approval to amend the rate schedules of PNG in accordance with this Application, effective January 1, 2012. PNG seeks such approval on an interim basis pursuant to sections 58 to 61, 89 and 90 of the Utilities Commission Act (the "Act"). The following narrative provides the submissions by PNG in support of the rates applied for in this Application.

INTRODUCTION

This Application sets out PNG's budgeted 2012 costs and forecast revenues using currently approved rates and forecast 2012 gas deliveries. The extent to which forecast revenues vary from forecast costs determines whether PNG is seeking Commission approval of rate increases or decreases. PNG compares its forecast 2012 costs to the Commission approved negotiated settlement of PNG's 2011 revenue requirements application ("NSP 2011") to put the 2012 figures in context. The forecast 2012 calendar year figures are identified in this Application under the heading "Test Year 2012".

This Application has been prepared using US Generally Accepted Accounting Principles ("US GAAP"). On October 6, 2011, PNG received Commission approval to use US GAAP for regulatory accounting and reporting purposes for the period January 1, 2012 to December 31, 2014. This Application includes a section entitled "Overview of Conversion to US GAAP" as directed by the Commission in their Order approving the use of US GAAP.

The following regulatory financial schedules are set out in this Application:

- Tab 1 - Utility Income & Return
- Tab 2 - Utility Rate Base
- Tab 3 - Income Taxes
- Tab 4 - Common Equity
- Tab 5 - Return on Capital

The regulatory schedules compare the Test Year 2012 figures to the NSP 2011 figures. In addition the actual historical cost of service figures are provided for the years 2008 to 2010 as agreed to under section 24.0 of the NSP 2011 settlement agreement. A Table is provided on the next page comparing the Test Year 2012 cost of service described in this Application to the NSP 2011 cost of service approved by the Commission. The NSP 2011 settlement agreement provided for \$700,000 of settlement allowance credits in 2011 (including a one-time \$500,000 credit as a result of the sale by PNG of its interest in Pacific Trail Pipelines in March, 2011). These one-time settlement allowance credits contribute significantly to the 2012 revenue deficiency and the resulting need to seek Commission approval of rate increases effective January 1, 2012.

See Tabs 6 and 7 for the Code of Conduct ("COC") and Transfer Pricing Policy ("TPP") respecting utility services provided by PNG to non-regulated business activities ("NRB").

Pacific Northern Gas Ltd.
(PNG-West Division)

TEST YEAR 2012 vs. NSP 2011
COST OF SERVICE COMPARISON
(\$000)

EXPENSES	Test Year	NSP	Difference	
	2012	2011	Total	Subtotal
Operating				
Labour	4,862	4,625	237	
Other	3,717	3,678	39	
Sub-total	<u>8,578</u>	<u>8,302</u>	<u>276</u>	
Maintenance				
Labour	244	207	37	
Other	403	284	119	
Sub-total	<u>647</u>	<u>492</u>	<u>155</u>	
Administrative and General				
Labour	2,724	2,442	283	
Total Company Benefits	3,317	2,820	497	
Other	3,064	2,823	241	
Sub-total	<u>9,105</u>	<u>8,085</u>	<u>1,020</u>	
Total (O, M, A & G) Excluding Co. Use	18,329	16,879	1,451	1,451
Transfers to Capital Operating	(399)	(675)	276	
Transfers to Capital Admin. & Gen.	(582)	(148)	(434)	
Property Taxes	3,696	3,637	59	
Depreciation	5,105	5,337	(232)	
Amortization	(632)	(1,016)	384	
Other Income	(751)	(300)	(451)	
Shared Services Recovery from PNG (N.E.)	(2,445)	(2,338)	(107)	
West Fraser Termination Payment	(1,806)	(1,687)	(118)	
PTP Settlement Allowance	0	(500)	500	
NSP Settlement Allowance	0	(200)	200	77
Total Expenses Excluding Co. Use	20,515	18,988	1,528	1,528
Income Taxes	937 ⁽¹⁾	1,126 ⁽²⁾	(189)	
Return on Common Equity	6,084	5,975	109	
Short Term Debt	644	355	289	
Long Term Debt	4,195	4,644	(449)	
Preferred Shares	351	351	0	(240)
Total Cost of Service Excluding Co. Use	32,726	31,438	1,288	1,288
Company Use Gas Cost	433	486		
Total Cost of Service Including Co. Use Cost	33,159	31,924		
2011 to 2012 Cost of Service Increase / (Decrease)			1,288	
2011 to 2012 Margin Decrease (Increase) / Decrease				(402)
2012 Revenue Deficiency / (Sufficiency)				886

1. Deferred income tax drawdown of \$ 1000
2. Deferred income tax drawdown of \$ 1000

COMPARISON OF TEST YEAR 2012 TO NSP 2011 COST OF SERVICE

The major components of the Test Year 2012 cost of service are summarized below in comparison to the corresponding figures approved under NSP 2011.

Cost of Service Items	(\$000's)		
	Test Year 2012	NSP 2011	2012/2011 Difference
Operating, maintenance, administrative and general Expenses	\$18,329	\$16,879	\$1,451
Transfers to capital operating, administrative and General	(981)	(823)	(158)
Other cost of service items including property taxes, depreciation, amortization, shared service cost recovery and NSP 2011 settlement allowances.	4,973	4,620	353
West Fraser Termination Payment	(1,806)	(1,687)	(118)
Return components including return on equity, income taxes and debt costs.	12,211	12,450	(240)
Total Cost of Service Ex. Co. Use Gas	\$32,726	\$31,438	\$1,288
Margin Using 2011 Rates	\$31,840	\$31,438	(\$402)
Test Year 2012 Revenue Deficiency			\$886
Total Cost of Service Ex. Co. Use Gas	\$32,726	\$31,438	
Company use gas cost pass through	433	486	
Total Cost of Service including Company Use Gas Cost	\$33,159	\$31,924	

The following explains in more detail the changes in various components of PNG's Test Year 2012 cost of service compared to the cost of service approved by the Commission under NSP 2011.

OPERATING EXPENSES

PNG's budgeted 2012 costs of operating its transmission and distribution facilities are summarized under the operating costs section of the Cost of Service Comparison Table. Test Year 2012, NSP 2011 and previous years' operating expenses by major cost component are summarized by BCUC Account in the Table below.

Operating Expenses

BCUC Account	\$000's					
	Test Year 2012	NSP 2011	2012/2011 Difference	Actual 2010	Actual 2009	Actual 2008
665 Pipelines	\$1,017	\$1,073	(\$55)	\$898	\$875	\$818
666 Compressors	411	401	\$10	393	372	406
667 Regulating Stations	242	199	\$43	290	292	312
670 Supervision	511	454	\$56	436	405	442
685 General Ops.	2,074	2,036	\$38	1,843	1,765	1,798
688 Other Gen. Ops.	1,404	1,356	\$48	1,318	1,405	1,100
711/713/714 Customer Care	1,422	1,412	\$9	1,294	1,298	1,246
Other inc. 673/675/712/718	1,497	1,372	\$126	1,483	1,440	1,401
Operating Expenses (Net of Co. Use Gas Cost)	\$8,578	\$8,302	\$276	\$7,955	\$7,852	\$7,523
Transfers to Capital	(399)	(675)	276	(532)	(573)	(628)
Sub-Total	\$8,179	\$7,627	\$552	\$7,423	\$7,279	\$6,895
Less N.E. Shared Service Recovery	(1,069)	(975)	(95)	(924)	(887)	(814)
Net Operating Expenses	\$7,110	\$6,652	\$458	\$6,499	\$6,392	\$6,081

Net operating expenses (i.e. gross operating expenses less the forecast cost of Company use gas) are increasing from \$8.303 million under NSP 2011 to \$8.578 million in Test Year 2012, an increase of \$275,000 or 3.3 percent. For comparison purposes, the Company use gas costs are netted off the operating costs as the Company use gas costs delivery rate is designed to recover from customers the gas supply costs incurred by PNG for its Company use gas requirements without mark up. The reason for the change in the level of transfers of operating expenses to capital is described later in this narrative in the context of the discussion on transfers to capital matters. The shared service cost recovery from PNG(N.E.) has increased over time due to changes in the shared service cost pool allocators as well as increases in the levels of expenses subject to allocation by the parent company PNG to its subsidiary PNG(N.E.). The reasons underlying the more significant operating expense changes from NSP 2011 to Test Year 2012 are provided below by BCUC Account.

Account 667 – Regulating Stations

The increased forecast Test Year 2012 expenditures of \$43,000 in this account more accurately reflects the actual costs historically incurred to ensure the on-going reliable operation of PNG's regulating stations. In particular, PNG notes that actual expenditures in this account over the 2008 to 2010 averaged \$298,000 per year. PNG considers the budget of \$242,000 for Test Year 2012 to be reasonable having regard to the level of actual expenses incurred in previous years.

Account 670 – Supervision

The increase of \$56,000 from NSP 2011 to Test Year 2012 is comprised of: higher field office rent and small tool expenses (\$15,000); increased labour expenditures, due in part to a 2011 forecasting error regarding standby charges (\$24,000); annual wage adjustment (\$7,000) and planning and other duties (\$10,000).

Account 685 – General Operations

The requirement to have PNG's Greenhouse Gas emissions reporting verified by a third party to comply with provincial reporting requirements (\$20,000) and increasing the forecast annual Oil and Gas Commission fees to reflect 2011 actual expenditure (\$17,000) are the components causing a forecast increase in this account.

Account 688 – Other General Operations

The single largest change in this account for 2012 is the increase in contractor charges (\$30,000) to create an avalanche safety plan to be compliant with new WorkSafe BC requirements. The remainder of the increase is due to an increased cost of labour resulting from the wage increase and allowable time off with pay due to years of service for certain individuals.

Account 712 – Meter Reading

The amount of forecast labour required to complete the meter reading requirements is being adjusted (\$25,000) to more accurately reflect the costs actually incurred in 2011. The 2011 budget did not accurately reflect the time required to complete all the regular meter readings as well as budget billing year end and other meter reads. See Tab 1, Page 3, Line 29.

Account 718 – Uncollectible Accounts

PNG's April 15, 2011 letter to the Commission stated the following respecting the above:

Uncollectible Accounts

For rate setting and for accounting purposes, PNG has been including an estimate of its annual bad debt expense based on the average bad debt expense in the previous 3 years adjusted for inflation. This amount historically constitutes approximately 0.65% of total revenues (excluding large industrials and off-system sales) for PNG West, 0.5% for PNG(N.E.)'s FSJ/DC division, and has varied from 0.05% to 0.25% for the PNG(N.E.) Tumbler Ridge division.

During the past three years, PNG commenced a new bad debt process using its Banner CIS system to better keep track of its aged receivables and has spent a substantial amount of time to clean up its "old" accounts receivables. PNG has also seen a decrease in uncollectible accounts.

As at December 31, 2010, on a consolidated company wide basis, PNG had an allowance for doubtful accounts of \$850,000 while accounts receivables greater than 90 days amounted to \$455,000 on a consolidated basis. Given this difference, PNG is proposing in the Updated Apr. 15'11 application not to record any bad debt expense for 2011 for PNG-West as there is an existing adequate allowance for doubtful accounts for the current year. This is expected to be a one-time occurrence in 2011.

Having no provision for uncollectible accounts in 2011 was a one-time occurrence as expected. For Test Year 2012, PNG has estimated the provision for bad debt expense to be approximately 0.25% of projected core market revenues. This amounts to the \$100,000 figure set forth under Tab 1, Page 3, Line 32 for Test Year 2012.

MAINTENANCE EXPENSES

BCUC Account	\$000's					
	Test Year 2012	NSP 2011	2012/2011 Difference	Actual 2010	Actual 2009	Actual 2008
866 Compressors	\$28	\$29	(\$0)	\$17	\$4	\$18
867 Regulating Stations	92	85	\$7	51	78	65
875 Mains and Services	145	124	\$21	164	122	121
878 Meters	230	157	\$73	157	94	55
Other inc. 865 and 885	152	97	\$55	95	49	85
Total	\$647	\$492	\$155	\$484	\$347	\$344

Account 865 – Pipelines

The forecast increase in expenditures (\$28,000) is due to third party costs related to the on-going stress corrosion cracking monitoring and assessment program.

Account 875 – Mains and Services

The forecast expenditures in the mains and services account are increasing from 2011 primarily due to an increase in labour (\$15,000) and contractor charges (\$3,000) being allocated to this account to address both above and below ground repairs/relocations to services and the associated risers.

Account 878 – Meters

The cost of having recalled meters tested and re-verified accounts for the majority of the forecast increase (\$52,000). Increased shipping (\$7,000) and labour (\$11,000) costs account for the remainder.

Account 885 – General

Materials related to the maintenance of tools and equipment including signs, barricades, PE tools and Mueller tools (\$14,000) and some minor contractor charges (\$3,000) are the main influences on the forecast expenditure increase for Test Year 2012.

ADMINISTRATIVE AND GENERAL EXPENSES

BCUC Account	\$000's					
	Test Year 2012	NSP 2011	2012/2011 Difference	Actual 2010	Actual 2009	Actual 2008
721 Administration	\$3,698	\$3,422	\$277	\$3,270	\$3,274	\$2,834
722 Special Services	639	525	114	541	645	458
723 Insurance	736	737	(1)	806	833	846
725 Employee Ben.	3,317	2,853	463	2,179	2,039	2,178
728 General	715	764	(49)	1,121	774	662
75x Non-Reg. Business Business	0	482	(482)	743	N/A	N/A
Sub-Total	\$9,105	\$8,783	\$321	\$8,660	\$7,565	\$6,978
Less Transfers to Capital	(582)	(148)	(434)	(821)	(851)	(1,011)
Sub-Total	\$8,523	\$8,635	(\$113)	\$7,839	\$6,714	\$5,967
Less Cost Adjustments	0	(698)	698	(874)	(125)	(153)
Less N.E. Shared Service Recovery	(1,376)	(1,364)	(12)	(1,112)	(1,070)	(993)
Total	\$7,147	\$6,573	\$573	\$5,853	\$5,519	\$4,821

Account 721 - Administration

The higher 2012 administration expenses in Account 721, which are explained below, are due to the following:

- Salary increase of 3% \$ 75,000
 - Salary adjustments for promotions/new hires 20,000
 - Adjustment for STIP 50,000
 - Inclusion of Director of Renewable Power as utility
personnel (credited to cost of service via TPP) 133,000
 - Head office rent 13,000
 - Reduction in consultants expenses (8,000)
 - Reduction in IT supplies (6,000)
- Total changes \$277,000

Salary Increase of 3% (\$75,000)

PNG is budgeting for an increase in 2012 of approximately 3 percent for its salaried non-bargaining unit administrative employees. The increase applicable to bargaining unit employees is 3.5 percent as agreed to under the current collective agreement that has a five year term ending October 31, 2012. In 2011, a 3.25% salary increase budget was applied to non-union and executive employees.

Salary Adjustments for Promotions/New Hires (\$20,000)

Some adjustments for promotions and new hires' salaries are provided for to reflect market conditions.

STIP adjustment (\$50,000)

As part of the NSP 2011 settlement negotiation process, PNG agreed to reduce the budget for employee bonuses in 2011 by \$39,000. The \$50,000 increase in Test Year 2012 is primarily due to addressing this settlement adjustment. The remainder of the difference reflects the 2012 forecast salary increase of 3%.

Inclusion of Director of Renewable Power (\$133,000)

With the new TPP and COC in place for 2012, PNG has included the salary of the Director of Renewable Power under Administration expenses and will charge out to NRBs assuming 95 percent of this position's time is spent on NRB activities. The TPP provides for recovery on a fully loaded basis, including a facilities charge and a general overhead charge. The details of the TPP and COC are set forth later in this narrative.

Head Office Rent (\$13,000)

The head office lease was renewed on January 2011 effective for September 1, 2011 to August 31, 2016. The \$13,000 increase reflects the incremental basic rent per the negotiated contract. PNG had engaged an expert in the office rental market to manage the lease renegotiation process during 2011.

Consultant Expenses (\$8,000 reduction)

Budgeted consultant expenses in 2012 are less than budgeted for 2011 based on a slight reduction in needs.

IT supplies expenses (\$6,000 reduction)

Budgeted IT supplies expenses in 2012 are \$6,000 less than budgeted for 2011 in an effort to manage controllable expenses.

Account 722 – Special Services

Costs for special services have increased due to an increase in consultants expenses anticipated to be incurred during 2012 for a consultant to prepare evidence on ROE and capital structure for inclusion in the 2013 revenue requirements application. (\$51,000). PNG is budgeting for a third party expert to complete an executive compensation review which was last completed in 2010 (\$26,000). The increase in legal fees (\$37,000) includes provision for engaging a lawyer for the public hearing process applicable to the 2012 revenue requirements application and expected increased legal requirements in 2012 based on a review of historical requirements.

Account 723 – Insurance

The 2012 insurance expense budget figure was determined through discussions with PNG's insurance brokers. Based on the brokers' advice, it is expected that the policy renewals in December 2011 will be accomplished at premiums equal to those in the prior year. Insurance is arranged by PNG on a consolidated basis, to achieve economies of scale, and the premiums are then allocated among the PNG-West and PNG(N.E.) divisions in accordance with the Commission's approved methodology set forth under Decision 2005. With growth of the PNG(N.E.) divisions exceeding that of PNG-West, there is a slight shift in the allocation of insurance costs from PNG-West to PNG(N.E.) in 2012 relative to 2011.

Account 725 – Employee Benefits

Employee benefits costs in 2012 are budgeted to increase by \$463,000. Approximately \$450,000 of this increase is due to higher Company pension plans costs. PNG's actuaries have provided a preliminary 2012 pension expense estimate which is higher than 2011 mainly due to a decrease in the discount rate (4.6% in 2012 versus 5.3% in 2011). The discount rate is lower primarily due to current financial market conditions and was determined following the new guidelines issued on September 21, 2011 by the Canadian Institute of Actuaries' Educational Note on the discount rate to be used for accounting purposes.

The Non-Pension Post-Retirement Benefits (NPPRB) are lower by approximately \$39,000 mainly due to the reset of its unamortized net actuarial gains and losses to zero (see “Overview of Conversion to US GAAP” section later in the narrative) offsetting the impact of the lower discount rate used to calculate the NPPRB expense.

Costs related to the employee savings plan have increased by \$39,000. The 2011 budget was inadvertently understated by \$21,000 and the balance of the increase reflects higher salaries forecast for 2012 along with an increased employer match (due to increased employee service).

Costs related to Ancillary Plan (ACP)/RRSP plans have increased by \$20,000 to reflect the actual forecast expenditures to be incurred in 2011 of \$52,000. The actual cost in 2010 was \$47,700 and the 2011 budget was only set at \$37,000. The budgeted cost for 2012 is \$57,210 which is comparable the anticipated cost of \$52,000 for 2011.

Account 728 – General

The \$49,000 decrease in this account from NSP 2011 to Test Year 2012 is due to lower budgeted costs as shown in detail at Tab 1, Page 5. The reductions by cost category are as follows:

• Fiscal and corporate expense -	\$16,000
• Directors fees and expenses -	\$ 3,000
• Regulation (i.e. BCUC fees) -	\$18,000
• Donations -	\$ 7,000
• Other -	<u>\$ 5,000</u>
Total	<u>\$49,000</u>

PNG will be reviewing its Account 728 budget for Test Year 2012 following the completion of the acquisition of PNG by AltaGas to determine what Account 728 expenses can be reduced due to PNG becoming a private company. PNG will be filing an update of this Application in the first quarter of 2012 and the update will reflect those cost adjustments accordingly.

Cost Adjustments

The above table shows a deduction from budgeted costs called “less Cost Adjustments”. The details of historical and the Test Year 2012 Administrative and General Expenses are provided under Tab 1 at page 5. For ease of reference the Cost Adjustments provided at the bottom of table are set forth below.

Account and Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
Cost adjustments					
50% of donations	0	(16)	(9)	(9)	(7)
Stock option benefit expense	0	(109)	(96)	(92)	(121)
Pension expense on bonuses and incentives	0	(33)	(27)	(25)	(25)
Non-regulated business & benefit allocations	0	(541)	(743)	0	0
Subtotal cost adjustments	0	(698)	(874)	(125)	(153)

There are no cost adjustment deductions for Test Year 2012 for the reasons set forth below.

PNG submits that 100 percent of its budget for donations should be included in its utility cost of service. PNG’s donations are made to organizations operating in its service territory and are considered to be a normal corporate expense that should be borne by ratepayers. The provision of \$25,000 in 2012 is considered to be an appropriate amount to be funded through customer rates.

The stock option benefit expense is a normal part of the compensation for a number of senior positions. This expense should be recoverable from ratepayers as it is a normal component of compensation for this industry sector. For the same reason, the pension cost of including bonuses in the pensionable earnings of PNG’s executives should be included in the Test Year 2012 cost of service (as is the case for non-executives). Bonus compensation incents the management team to optimize operational efficiency and safety to the common benefit of the customer and all stakeholders.

The Test Year 2012 cost adjustment deduction for “Non-regulated business” is set at zero because PNG has decided to remove from the revenue requirement presentation a budget for non-regulated business under Account 75x. This decision was made having regard to the implementation of the new TPP and COC, which is described in the next section.

TRANSFER PRICING POLICY AND CODE OF CONDUCT

The COC and TPP are set forth under Tabs 6 and 7, respectively. They govern the use of utility resources for NRB activities. Under section 22 of the NSP 2011 settlement agreement, PNG agreed to prepare a COC and TPP for consideration in 2012. The issue description in section 22 of NSP 2011 was stated as “Should the reduction for NRB costs as set forth at Tab 2, Page 5, Line 31 of the Application be increased?” PNG has shown a credit for the recovery of the cost of utility resources used for NRB under miscellaneous operating revenue and other credits at Tab 1, page 7, line 9.

Hourly rates have been developed in accordance with the methodology set forth in the TPP for all of the utility employees that PNG expects will be working on NRB in 2012. PNG’s utility employees who are expected to work on NRB matters in 2012 have estimated the amount of time they will spend on NRB. The credit under miscellaneous operating revenues is the fully allocated charge to the NRB for the use of utility resources and includes the calculated amount of NRB time in hours times each employee’s hourly rate for those utility employees that budget NRB work. It also includes a benefits allocation, a facilities charge and a general overhead charge as per the TPP. The 2011 revenue requirements application included in miscellaneous revenue an item entitled “NRB Administration Fee Recovery”. The \$31,000 figure was the amount PNG was charging its McNair Creek hydro-electricity generating project primarily for the provision of accounting services by an utility employee. This item is no longer identified in miscellaneous operating revenue because it is effectively included in the Utility charges to NRB section of miscellaneous operating revenue.

Approximately 17 employees from the Vancouver head office have budgeted for work on NRB. At present, only Vancouver head office utility employees devote their time to NRB. As noted above, hourly rates have been developed for all Vancouver head office personnel and processes have been developed to ensure that when an employee works on NRB, their time will be allocated to NRB.

The acquisition of PNG by AltaGas Ltd. may result in the number of hours forecast by PNG to be expended on NRB activities in 2012 to be modified when PNG files its update to this Application in February/March 2012. PNG will be reviewing a number of matters with AltaGas, including PNG’s level of involvement in the renewable power sector, given the significant interests held by AltaGas in this sector.

TRANSFERS TO CAPITAL

PNG has used the capital overhead allocation methodology approved under NSP 2011 to calculate the transfers of budgeted 2012 operating, administrative and general expenses to capital. PNG is using the same capitalization overhead rates for both rate setting purposes and for external reporting purposes.

PNG has made one reclassification in the presentation of Transfers to Capital as the benefits loading associated with field personnel was included under “Transfers to Capital – Operating Expenses” in NSP 2011 instead of under “Transfers to Capital – Administrative and General Expenses” as all employee benefits are included under BCUC Account 725 Employee Benefits.

Overall, there has been an increase in Transfers to Capital of approximately \$156,000 mainly due to the increase in salaries, increase in benefits loading due to the higher pension expense and higher direct charges to capital projects and their associated benefits loading amounts.

PROPERTY TAXES

Cost Element	\$000's					
	Test Year 2012	NSP 2011	2012/2011 Difference	Actual 2010	Actual 2009	Actual 2008
Property Taxes	\$3,287	\$3,188	\$99	\$3,092	\$3,079	\$2,989
1% in Lieu	409	449	(40)	468	448	521
Total	\$3,696	\$3,637	\$59	\$3,560	\$3,527	\$3,510

Actual property taxes, based on the assessed value of PNG’s real property, were \$3,172,000 in 2011 resulting in a \$16,000 property tax credit deferral which will be amortized in 2012. The 2012 transmission pipeline assessments have been set at a 2.5% increase relative to 2011. Given this increase and an expected increase in mill rates, PNG expects 2012 property taxes to be 3.6 percent higher than actual 2011 property taxes. The 1 percent in lieu component of property taxes for 2012 is based on actual revenues recorded in 2010.

DEPRECIATION

The forecast Test Year 2012 depreciation expense has been calculated using depreciation rates determined on the basis set forth in PNG's 2011 revenue requirements application. Section 5.0 of the NSP 2011 settlement agreement provided the following with respect to depreciation:

“Depreciation expense will be determined on the basis proposed in the Application for Test Year 2011 only. PNG will obtain an independent review of the reasonableness of the areas where PNG management decided to vary from the Depreciation Study recommendations including the depreciation expense calculation, the decision to use the specifically identified assets methodology rather than the recommended group methodology for asset classes 484, 485, and 479 and the decision to adopt the ASL procedure rather than ELG. Gannett Fleming is an acceptable third party to carry out this review. The results of the review will be included with PNG's 2012 revenue requirements application. PNG's next revenue requirements application will use the same depreciation rates for rate setting purposes as it does for financial reporting.”

A copy of a letter from Gannett Fleming is reproduced on the following pages in response to PNG's agreement to “obtain an independent review of the reasonableness of the areas where PNG management decided to vary from the Depreciation Study recommendations including the depreciation expense calculation, the decision to use the specifically identified assets methodology rather than the recommended group methodology for asset classes 484, 485, and 479 and the decision to adopt the ASL procedure rather than ELG.” The letter supports management's decisions regarding the determination of depreciation rates as set forth in its 2011 revenue requirements application.



Gannett Fleming

*Excellence Delivered **As Promised***

November 25, 2011

Pacific Northern Gas
Suite 950 – 1185 West Georgia Street
Vancouver, British Columbia
V6E 4E6

Attention: Ms. Janet Kennedy

Gannett Fleming, Inc. Review of the Calculation of Depreciation Expense

Gannett Fleming, Inc. (“Gannett Fleming”) has reviewed the discussion related to depreciation rates in Section 5.0 of Appendix A to BCUC Order G-92-141. As per your request Gannett Fleming has provided the Attached “Gannett Fleming Review of Depreciation Expense”.

The attached document specifically replies to the order for PNG to “obtain an independent review of the reasonableness of areas where PNG management decided to vary from the depreciation study recommendations including the depreciation expense calculation, the decision to use the specifically identified assets methodology rather than the recommended group methodology for asset classes 484, 485, and 479 and the decision to adopt the ASL procedure rather than ELG.”

If you have any questions on the comments in the attached review, please feel free to call me at (403) 257-5946.

Sincerely,

GANNETT FLEMING, INC.
Valuation and Rates Division

A handwritten signature in blue ink, appearing to read 'L. Kennedy'.

Larry E. Kennedy
Director, Canadian Services

LEK/hac

PACIFIC NORTHERN GAS
GANNETT FLEMING, INC. REVIEW
OF THE CALCULATION OF DEPRECIATION EXPENSE

PROVIDED IN RESPONSE TO BCUC ORDER G-92-11

Composite Rate vs. Remaining Useful Lives

The Gannett Fleming depreciation study developed depreciation rates based on the plant in service as at December 31, 2009. The depreciation rates calculated within the depreciation were calculated using the Average Service Life (ASL) Procedure applied on a remaining life basis. The depreciation study, in Section V-Detailed Calculations, determined the appropriate level of annual depreciation accrual for each vintage of installed plant by dividing the net book value of the plant within the vintage by the remaining life of each vintage. The annual accrual for each vintage was then summed and divided by the net book value to determine a composite remaining life. The sum of the accruals for each vintage was also divided by the original cost of installed plant to determine a composite remaining life depreciation accrual rate.

For the determination of its depreciation expense as per its 2011 rate filing, PNG used the remaining useful lives for each vintage as provided in the depreciation study rather than the group composite rate and calculated the expense by dividing the net book value of each vintage by the remaining life applicable for each vintage as at the calculation date. This estimation is consistent with the implementation of the Gannett Fleming depreciation study results into the PNG accounting systems. In order to implement the results of the Gannett Fleming depreciation study, PNG entered into its plant accounting ledgers, the remaining life applicable for each vintage of each asset account. The remaining life used was based on the applicable vintage remaining life from the Gannett Fleming study. As such the PNG annual calculations are based on the results of the remaining life calculations from the Gannett Fleming study. In developing the depreciation expense, the PNG system divides the net book value of each vintage within each account by the remaining life as at the date of the calculation. Gannett Fleming notes that this is a mirrored version of the same calculation as made in the Gannett Fleming study in order to develop a composite depreciation rate.

The vintage distribution of the plant in service as used in the Gannett Fleming depreciation study was developed using an extract of the PNG plant accounting ledgers which provided an in service date. As such, the depreciation study data is consistent with the plant accounting ledgers of PNG. The composite depreciation rates as developed in the depreciation study, if applied to the plant accounting balances would result in a level of depreciation expense consistent with the depreciation expense resulting from the procedures currently used by PNG. As such, the PNG procedures are following the recommendations within the Gannett Fleming study, and Gannett Fleming finds that the current PNG procedures for the calculation of depreciation expense are appropriate and reasonable. Gannett Fleming further finds that the manner in which the forecast 2011 depreciation expense was determined is consistent with the results of the Gannett Fleming depreciation study.

Use of the ASL Procedure vs the Equal Life Group (ELG) Procedure

As indicated above, PNG has implemented the Gannett Fleming depreciation study by applying the same composite remaining life to all investment for each vintage installation within a group. This implementation procedure is more conducive to the calculation of depreciation rates developed using the ASL procedure rather than the ELG procedure. Depreciation rates calculated using the ELG procedure have a number of individual remaining life calculations applied to each of the installed plant vintages. As such, the remaining life calculation applied to each vintage is already a composite remaining applicable to the vintage. While in the view of Gannett Fleming, this separation of the installed costs by vintage into a number of individual remaining life groups provides increased accuracy, it would be virtually impossible to implement within the PNG accounting system. In contrast with the ASL procedure, the same remaining life calculation is applied to

all costs within a vintage. This allows for the easier conversion from the summed depreciation accruals inherent in the composite remaining life and depreciation rate from the depreciation study to the implementation requirements within the PNG accounting systems.

As indicated previously, the PNG system calculates depreciation expense by dividing the net book value of each vintage of the asset by the remaining life of the asset class vintage. The current net book value of each vintage of the asset class has not recognized that each vintage of installed plant can have a number of individual remaining life estimates, and at least conceptually, a number of individual and differing net book values. As such it would be virtually impossible to assign a correct ELG determined remaining life to each vintage as is required within the PNG systems. Given the wide spread use of the ASL procedure throughout North America, and further given that the ELG procedure had not been previously approved for use by the BCUC, Gannett Fleming views that the merits associated with the conversion to the ELG procedure would not be justified given the costs and administrative burden associated to implement the ELG procedure. As such, Gannett Fleming views that the use of the ASL procedure is reasonable in the current circumstances of the current PNG system.

Unit Depreciation Method – Asset Classes 484, 485 & 479

The assets that comprise asset classes 484 – Transportation Equipment; 485 – Heavy Work Equipment and Account 479 – Other Distribution Equipment are large, identifiable and easily tracked by unit. In fact these assets largely need to be tracked by individual unit for other business requirements. The company has developed policies with regard to the replacement of the assets in these accounts, and can easily determine the remaining life of each unit. As such, the depreciation on the assets within these accounts can easily be tracked on a unit depreciation basis. In the circumstances of these accounts with highly identifiable and individually tracked assets the use of unit depreciation provides a reasonable and appropriate level of depreciation expense.

The Depreciation Study completed in 2011 had regard to PNG's expectation that it would be transitioning to International Financial Reporting Standards ("IFRS"). PNG obtained Commission approval under Order G-168-11 dated October 6, 2011 to adopt Accepted US GAAP for regulatory accounting and financial reporting purposes commencing January 1, 2012 and ending on December 31, 2014. PNG confirms that the adoption of US GAAP has not required a change to how depreciation will be determined by PNG for regulatory accounting and financial reporting purposes going forward compared to what was done in 2011. However, as is noted under the Overview of Conversion to US GAAP, PNG will return to its practice of commencing depreciation on new additions effective January 1 of the year following the year in which the addition was completed. This is easier to administer and accurately forecasts total depreciation expense.

Total depreciation expense forecast for 2012 is lower than NSP 2011 by \$232,000. This is mainly because the 2011 depreciation included life to date adjustments to transportation, office, and computer equipment and tools as many assets in these categories were under depreciated as per the Depreciation Study. Also, as noted above, PNG will return to the practice of commencing depreciation on new additions effective January 1 of the year following when the addition was completed. Hence, no depreciation on forecast 2012 capital additions is included in Test Year 2012 depreciation expense.

AMORTIZATION

	(\$000's)		
	Test Year 2012	NSP 2011	2012/2011 Difference
Gross Amortization	(\$632)	(\$1,016)	\$384
Future Income Taxes	189	291	(102)
Net of FIT	(\$443)	(\$725)	\$282

	Account Type		Amortization Expenses (\$000's)		
	Rate Base - RB Interest Bearing - IntB		Test Year 2012	NSP 2011	2012/2011 Difference
Deferral Accounts	Test Year 2012	NSP 2011	Test Year 2012	NSP 2011	2012/2011 Difference
Line Break Costs	RB	RB	170	174	(4)
Plant Gains and Losses	RB	RB	135	27	108
Investigative Digs	RB	RB	69	50	19
IFRS and US GAAP	RB	RB	184	0	184
Pipeline Inspections	IntB	IntB	62	193	(131)
Industrial Customer Deliveries	IntB	IntB	(59)	(29)	(30)
BCUC Fees	IntB	IntB	(19)	2	(21)
BCUC Proceedings	IntB	IntB	4	4	(1)
Property Tax Variance	IntB	IntB	(17)	(47)	31
Short Term Interest	IntB	IntB	12	14	(1)
Long Term Interest	IntB	IntB	(52)	(84)	33
CAP/ROE Hearing	NA	IntB	3	88	(86)
2011 Depreciation Adjustment	IntB	IntB	(49)	0	(49)
Propane Air Plant	NA	IntB	78	54	24
Old Revolving Debt Issue Costs	NA	IntB	(0)	88	(88)
LNG Partners Option Fee Payment	IntB	IntB	(1,155)	(1,582)	427
		Subtotal	(\$632)	(\$1,047)	\$415
		Future Income Taxes	189	322	(133)
		Net Total	(\$443)	(\$725)	\$282

The Table above provides gross amortization and then a deduction of the future income taxes at the bottom of the Table to result in the after tax amortization expense. Schedule 1 Utility Income and Return shows the gross amortization figures with an offsetting deduction to income tax expense equal to the associated future income tax. More detailed commentary is provided below in the context of each deferral account.

Line Break Costs

There were no additions to this deferral account in 2011. Consequently, the Test Year 2012 amortization is essentially the same as in 2011. The amortization period is ten years.

Plant Gains and Losses

This deferral account is used to record extraordinary plant losses and the undepreciated value of assets that were retired but not fully depreciated (i.e. recoverable from customers) or over depreciated (i.e. to be credited to customers) . It will also be used to record gains and losses from the disposal of assets as per NSP 2011 Settlement. The last paragraph of section 6.0 of the NSP 2011 settlement agreement also stated the following:

“PNG requested at Tab Application, Page 23 of Exhibit B-1 to record an addition of \$927,585, based on December 31, 2009 balances, to its Plant Gains and Losses rate base deferral account to reflect the undepreciated value of assets that were retired but not fully depreciated. However, the request was withdrawn in the amendments to the Application filed as Exhibit B-1-3 and during negotiations the request was restored. The parties agreed to PNG’s restored request provided that no amortization could be taken in Test Year 2011 on these assets. Furthermore, the parties did not consider PNG’s ability to recover the balance in a future period nor did they discuss whether the sum of the net book values (NBV) of the individual assets as compared against the NBV of the entire asset class amounted to \$927,585 as PNG stated in the Application. The parties agreed that the recoverability, amortization period and dollar value of the deferral account will be addressed as part of PNG’s next revenue requirements application.”

The makeup of the \$927,585 figure set forth at Tab Application, Page 23 of PNG’s original 2011 revenue requirements application is set forth in the table below. This figure was based on information available in November 2010. When the final NSP 2011 regulatory schedules were filed with the Commission in May 2011 the year end 2010 figures were available and the figures in the table below under the “NSP 2011 Actual” heading were reflected in the final NSP 2011 regulatory schedules accordingly.

BCUC Accounts	2011 RR App. Forecast 2010	NSP 2011 Actual 2010
479 – Other Distribution Equipment (Propane /Air Plant)	\$152,758	\$152,758
480 - Land	(\$23,397)	(\$23,397)
484 – Transportation Equipment	\$696,323	\$844,730
485 – Heavy Equipment	\$101,901	\$106,204
Total	\$927,585	\$1,080,295

As noted in the NSP 2011 settlement agreement, none of the \$1,080,295 figure was amortized in 2011. This account also includes other plant losses incurred in prior years (such as Porpoise Harbour) which will have a remaining unamortized balance of \$191,000 at December 31, 2011.

The forecast year end 2011 balance in this deferral account is \$1,535,000. The forecast addition in 2011 of \$264,000 is comprised of the following:

Forecast 2011 Plant Losses	Amount
Loss on Gitnadoix Tunnel 8" Pipe	\$242,972
Loss on Uninterrupted Power Supply system replacement	15,541
Other Plant losses	5,487
Total	\$264,000

PNG considers it is appropriate to recover the undepreciated value of assets that were retired but not fully depreciated in this deferral account because the initial depreciation rate accorded to this group of assets was too low. Had the proper useful life of the asset been determined correctly, these amounts would have been recovered through depreciation expense in prior years. This has been corrected for new asset additions in these asset classes as per the Depreciation Study that was reviewed under the 2011 revenue requirements application process.

PNG is seeking Commission approval to amortize the balance in the Plant Gains and Losses deferral account over 10 years. PNG considers the 10 year period to be appropriate for this deferral account. The increase in amortization expense from NSP 2011 to Test Year 2012 is primarily due to the addition of the above amounts to the Plant Gains and Losses deferral account.

Investigative Digs

The amortization expense in 2012 represents the ten year amortization of the forecast year end 2011 balance in this rate base deferral account. See Tab 2, Page 12 for the estimated addition in 2011 to this account. The forecast additions in 2012 represent PNG's budgeted investigative digs based on a review of expected requirements. There is no change to the amortization period or methodology applicable to this deferral account.

IFRS and US GAAP

The IFRS deferral account commenced in 2009 to record third party costs incurred to facilitate the conversion to IFRS. In 2011 PNG decided to adopt US GAAP for regulatory accounting and financial reporting purposes. PNG obtained Commission approval under Order G-168-11 dated October 6, 2011 to adopt US GAAP. Section 3 of this Order approved PNG's "request to record one-time conversion costs associated with the adoption of US GAAP in a US GAAP rate base deferral account". For ease of reference, PNG has recorded the US GAAP adoption costs incurred to date in 2011 as part of the pre-existing IFRS deferral account given the fact both matters relate to accounting changes.

Section 4 of Order G-168-11 directed PNG "to seek approval for the amortization period and recoverability of the US GAAP deferral account and to address the disposition of the previously incurred IFRS conversion costs as part of the 2012 RRA." PNG is seeking Commission approval to amortize the joint IFRS/US GAAP projected year end 2011 balance over the 2012 to 2014 three year amortization period. PNG considers three years to be appropriate given this is the initial period of time over which PNG will initially apply US GAAP pending further review in 2015. As noted in the US GAAP application, total conversion costs expected to be incurred in 2011 (\$250,000) and 2012 (\$150,000) have been included as additions to the deferral account in their respective years and allocated to each division based on rate base.

Pipeline Inspections

This deferral account records the difference between budgeted and actual pipeline inspection costs. As of the date of this Application, it is expected that the difference between budgeted and actual 2011 inspection costs will be minimal. This will be updated at year end 2011. The Test Year 2012 amortization expense is based on a one year amortization period, the same period historically applied to this account.

Industrial Customer Deliveries

This deferral account is used to record the difference between the forecast margin used to set rates and actual margin recovery from three industrial customers (i.e. Rio Tinto Alcan, BC Hydro and Conifex). The forecast credit addition in 2011 reflects primarily an increase in margin recovery from Conifex due to 2011 deliveries exceeding budgeted deliveries.

BCUC Fees

The addition for 2011 is the amount by which actual BCUC fees in 2011 was less the forecast figure included in the 2011 budget for rate making purposes.

BCUC Proceedings

The BCUC Proceedings deferral account records the difference between budgeted costs used for rate making purposes and actual costs. There is no addition in 2011 and this may change when the final regulatory schedules are filed with the Commission in 2012.

Property Tax Variance

The Property Tax Variance deferral account records the difference between budgeted costs used for rate making purposes and actual costs. There is a credit addition in 2011 which is being amortized in 2012.

Short Term Interest

No changes are requested with regard to how this deferral account is administered by PNG.

Long Term Interest

No changes are requested with regard to how this deferral account is administered by PNG.

CAP/ROE Hearing Costs

This deferral account was fully amortized in 2011 and hence the reason for no amortization expense in Test Year 2012.

Propane Air Plant

No changes are requested with regard to how this deferral account is administered by PNG.

2011 Depreciation Adjustment

This is a new deferral account that PNG is requesting the Commission to approve. In the 2011 revenue requirement application, PNG had applied and obtained Commission approval to commence recording depreciation as soon as a capital addition was put into service in order to be compliant with IFRS and had included \$47,475 of anticipated depreciation on 2011 additions in the 2011 cost of service. PNG is now requesting Commission approval to return to the historical methodology of commencing to record depreciation on additions in the year following the year when the addition was completed which is allowed under US GAAP. The credit of \$47,475 recorded in this deferral account in 2011 adjusts for the fact PNG is returning to this historical methodology. The forecast of depreciation in Test Year 2012 has been determined using the historical methodology and in accordance with the Depreciation Study filed with the 2011 revenue requirements application and accepted under NSP 2011. This deferral account will be fully amortized in 2012 and will not exist post 2012.

Old Revolving Debt Issue Costs

This deferral account was fully amortized in 2011 and hence the reason for no amortization expense in Test Year 2012.

LNG Partners Option Fee Payment

PNG is proposing to amortize in 2012 one third of the currently estimated year-end 2011 credit balance in the LNG Partners Option Fee Payment deferral account. PNG has yet to receive the \$1 million option fee extension payment due in December 2011 to extend the option to June 30, 2012. However, PNG has assumed this payment will be made based on the fact LNG Partners continues to pursue their LNG export license application before the National Energy Board. PNG is recommending using a three year amortization period as LNG Partners can commence taking service as late as January 1, 2015 (i.e. three years from now). Only credit interest is shown as an addition in 2012 since the extension to June 30, 2012 is the last extension currently allowed under the PNG/LNG Partners agreement and no further option extension fee payments are provided for under PNG/LNG Partners agreement.

MISCELLANEOUS OPERATING REVENUES & CREDITS

For ease of reference, the Miscellaneous Operating Revenues & Credits figures at Tab1, Page 7 are reproduced below. Following the figures is PNG’s discussion of the two major components of these revenues and credits (i.e. Shared Services cost recovery from PNG(N.E.)’s Fort St. John/Dawson Creek and Tumbler Ridge divisions and the Utility charges to NRB).

(000's)					
Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
Penalty charges	\$94	\$94	\$92	\$102	\$96
Connection Fees	96	105	92	104	106
Rents	6	6	6	3	0
Overheads recovered	42	62	153	52	13
Automotive surcharges	(0)	(0)	0	0	(0)
Commission - PST Tax	0	0	2	1	1
Shared Services - Tumbler Ridge	156	149	130	126	123
Shared Services - FSJ / DC	2,289	2,189	1,907	1,831	1,685
Utility charges to NRB	511	31	0		
Other	2	2	2	386	2
	\$3,196	\$2,638	\$2,383	\$2,605	\$2,026

The reasons for the significant increase in Utility charges to NRB from NSP 2011 to Test Year 2012 is provided later in this Application under the heading “Utility Charges to NRB”.

PNG SHARED SERVICE COST RECOVERY FROM PNG(N.E.)

PNG provides many supporting services to PNG(N.E.)'s Fort St. John/Dawson Creek and Tumbler Ridge divisions that serve communities in northeastern B.C. PNG has established that PNG(N.E.)'s costs of securing these services on a standalone basis would significantly exceed the amount charged by PNG for such services. The cost to be recovered by PNG from PNG(N.E.) in 2012 is reflected as a credit to the PNG-West 2012 cost of service for rate making purposes. It is noted that the NSP 2011 provided the following with respect to reviewing shared services between PNG and PNG(N.E.):

“PNG will file with the Commission a Cost Allocators and Level of Shared Service Cost Recovery Application as a standalone application in the Fall of 2012. The application will be based on a shared services cost study prepared by a third party consultant (Shared Services Study).”

PNG expects any changes to the status quo arising out of the Shared Services Study will be reflected in its 2013 revenue requirements application. Therefore, PNG is also assuming that the status quo will apply to this Application with respect to how PNG calculates the level of shared service cost recovery from PNG(N.E.) in 2012.

The Table on the next page provides a detailed summary of historical shared service costs and those applied for under this Application using the same cost allocators as used under NSP 2011. Discussion of changes from 2011 to 2012 follows the Table.

COST POOLS		Test Year 2012	NSP 2011	NSP 2010	NSP 2009	NSP 2008
721 – Vancouver Administration (Time Study)	Cost Pool:	\$3,309,683	\$3,399,025	\$3,184,924	\$3,094,939	\$2,786,828
	Fixed %:	20.84%	20.84%	20.84%	20.84%	20.84%
	Labour:	\$503,686	\$508,819	\$486,887	\$450,116	\$410,684
	Benefits %	35.80%	38.95%	27.81%	29.10%	31.47%
	Recovery:	\$870,050	\$906,551	\$799,127	\$775,950	\$710,023
685 – Terrace Engineering (Time Study)	Cost Pool:	\$198,844	\$162,209	\$141,714	\$147,714	\$137,333
	Fixed %:	20.84%	20.84%	20.84%	20.84%	20.84%
	Labour:	\$0	\$0	\$0	\$0	\$0
	Benefits %	0.00%	0.00%	0.00%	0.00%	0.00%
	Recovery:	\$41,439	\$33,804	\$29,533	\$30,784	\$28,620
685 – Terrace Management (Customer Count)	Cost Pool:	\$543,840	\$527,987	\$422,241	\$425,356	\$339,821
	Fixed %:	48.04%	47.60%	46.79%	46.17%	44.66%
	Labour:	\$237,526	\$228,468	\$179,622	\$178,516	\$137,962
	Benefits %	29.37%	30.58%	27.81%	29.10%	31.47%
	Recovery:	\$338,016	\$328,167	\$252,527	\$253,503	\$199,519
685 – Terrace Accounting/ Warehouse (Employee Count)	Cost Pool:	\$577,785	\$495,114	\$607,216	\$528,655	\$583,024
	Fixed %:	24.60%	24.60%	24.60%	24.83%	24.27%
	Labour:	\$88,427	\$81,831	\$99,308	\$94,005	\$110,580
	Benefits %	55.92%	50.08%	27.81%	29.10%	31.47%
	Recovery:	\$191,584	\$162,774	\$176,986	\$158,635	\$176,312
685 – Terrace Drafting (Customer Count)	Cost Pool:	\$130,851.5	\$81,278.4	\$79,219.4	\$67,949	\$67,382
	Fixed %:	48.04%	47.60%	46.79%	46.17%	44.66%
	Labour:	\$28,970	\$14,669	\$14,204	\$17,717	\$20,842
	Benefits %	55.92%	50.08%	27.81%	29.10%	31.47%
	Recovery:	\$79,067	\$46,033	\$41,020	\$36,524	\$36,651
Total 685	Recovery:	\$650,107	\$570,779	\$500,066	\$479,445	\$441,103
711/713/714 Terrace Customer Care Centre (Customer Count)	Cost Pool:	\$1,168,535	\$1,111,355	\$1,091,483	\$1,077,156	\$1,035,334
	Fixed %:	48.04%	47.60%	46.79%	46.17%	44.66%
	Labour:	\$425,021	\$379,335	\$355,273	\$325,838	\$307,647
	Benefits %	55.92%	50.08%	27.81%	29.10%	31.47%
	Recovery:	\$799,096	\$718,951	\$609,541	\$592,079	\$559,185
728 – Corporate Expenses (Rate Base)	Cost Pool:	\$494,259	\$570,009	\$520,438	\$497,642	\$468,254
	Fixed %:	25.46%	24.88%	23.65%	22.06%	20.76%
	Labour:	\$0	\$0	\$0	\$0	\$0
	Benefits %	0.00%	0.00%	0.00%	0.00%	0.00%
	Recovery:	\$125,852	\$141,839	\$123,101	\$109,784	\$97,220
Total Recovery		\$2,445,105	\$2,338,121	\$2,031,836	\$1,957,259	\$1,807,531

The Account 721 Vancouver Administration cost pool would have been higher compared to the level of the cost pool under NSP 2011 but for the adjustment made to this cost pool to reflect the forecast recovery of Account 721 Vancouver Administration costs from NRBs under the TPP. Hence, the otherwise applicable increases in this cost pool have been more than offset by the reductions to the cost pool to account for recovery from NRBs.

The Terrace Engineering cost pool includes a number of third party costs. The increase from 2011 to 2012 is due to the addition of \$21,000 for third party costs related to PNG's integrity management programs and an increase in Oil and Gas Commission fees of \$18,000.

The cost pool for Terrace Accounting/Warehouse cost pool is increasing from 2011 to 2012 due to a number of different causes including \$23,000 for meter recall handling and \$30,000 for sample meter handling. The remainder reflects more accurate budgeting.

The cost pool for Terrace Drafting is increasing by a relatively substantial amount. The current draftsman has advised of his plans to retire by November 2013 at the latest. This date could be advanced depending on whether the current backlog of work can be completed with assistance from another draftsman. PNG has decided to hire another draftsman in the first quarter of 2012 to address the back log of work and provide sufficient time for the current draftsman to train the new employee. This is a temporary situation as there will only be one position following the retirement of the current draftsman.

The 728 - Corporate Expenses cost pool is declining from 2011 to 2012 for two reasons. Some of the costs in this pool are declining as noted earlier in this narrative. In addition, the cost pool has been reduced to reflect the corporate expenses being recovered from NRBs under the TPP.

UTILITY CHARGES TO NRB

The Test Year 2012 forecast of utility charges to NRB is the main reason for the increase in "Investment income, other revenue & credits" from 2011 to 2012 as shown at Tab 1, Page 1, Line 27. The TPP set out under Tab 7 describes the methodology followed by PNG to estimate the appropriate value of utility resources forecast to be used for NRB matters in 2012. The rationale for the TPP and accompanying COC was described earlier in this Application narrative.

WEST FRASER MILLS CONTRACT TERMINATION PAYMENT

The credit for the above shown at Tab 1, Page 1, Line 28 reflects the amortization of a contract termination payment of just over \$5 million that West Fraser paid PNG on December 1, 2011. Section 1.0 of the NSP 2011 settlement agreement stated:

“PNG’s proposal to record the contract termination payment in an interest bearing deferral account and to amortize the payment in equal monthly amounts as a credit to the cost of service over the 37 month period from December 1, 2010 to December 31, 2013 is accepted.”

PNG requests Commission approval under this Application to continue with the amortization of the termination payment as agreed to under NSP 2011.

INCOME TAXES

	(\$000's)		
	Test Year 2012	NSP 2011	2012/2011 Difference
Tax before FIT	\$937	\$1,126	(\$189)
FIT on Deferrals	(189)	(291)	102
Total	\$748	\$835	(\$87)

The Test Year 2012 income taxes are lower compared to NSP 2011 primarily due to lower depreciation expense and to a reduction in the income tax rate from 26.5 percent to 25.0 percent. The 2012 income tax expense also reflects PNG’s recommendation to draw down \$1,000,000 of deferred income taxes as a credit to income taxes which is the same deduction that applied under NSP 2011.

CAPITAL STRUCTURE AND RETURN ON COMMON EQUITY

	Test Year 2012	NSP 2011	2012/2011 Difference
Rate of Return on Equity	10.15%	10.15%	0
Common Equity Thickness	45%	45%	0
Common Equity (000's)	\$59,942	\$58,864	\$1,078
Return on Equity (000's)	\$6,084	\$5,975	\$109

PNG is recommending that the rate of return on equity and the deemed common equity thickness for Test Year 2012 be maintained at the same levels as agreed to under NSP 2011. A higher rate base has resulted in a higher common equity and return on equity in Test Year 2012 compared to NSP 2011.

SHORT TERM DEBT INTEREST EXPENSE

\$000's		
Test Year 2012	NSP 2011	2012/2011 Difference
\$644	\$355	\$289

The short term debt component of PNG's capital structure for rate making purposes balances the capital structure to the rate base. The increase in short term debt interest expense for 2012 reflects a general increase in interest rates forecast for 2012 compared to 2011 as well as a significantly larger amount of short term debt outstanding. Specifically, the average short term interest rate is projected to increase from 5.11 percent under NSP 2011 to 6.13 percent in Test Year 2012. The forecast interest rate on operating line borrowings is a consensus forecast of the average prime rate for 2012 taken from the October 2011 Econolink Report, plus PNG's credit spread of 100 basis points. The forecast customer deposit interest rate for 2012 has been increased from 2011 by the increase in the forecast average prime rate from the Econolink Report.

LONG TERM DEBT INTEREST EXPENSE

\$000's		
Test Year 2012	NSP 2011	2012/2011 Difference
\$4,195	\$4,644	(\$449)

The 2012 long term debt interest expense reflects both lower long-term debt levels in PNG's capital structure and lower average interest rates compared to the projection used in NSP 2011. The projected interest rate on long term debt is forecast to decrease from 7.74 percent under NSP 2011 to 7.26 percent for Test Year 2012, mainly due to the maturity of PNG's 10.75% debenture in late 2011 which was refinanced with PNG's revolving term facility having an effective cost rate of 4.90% in 2012.

COMPANY USE GAS COST

	Test Year 2012	NSP 2011	2012/2011 Difference
Total Cost	\$433,150	\$485,927	(\$52,777)
Requirements in GJ	68,332	78,230	(9,898)
Forecast Unit Gas Cost	\$4.513/GJ	\$4.753/GJ	(\$0.240/GJ)

The quantity of forecast Company use gas to be purchased by PNG has decreased from NSP 2011 to Test Year 2012 due to decreases in some of the Company use gas components to reflect recent historical experience. The lower overall cost also reflects a lower projected gas commodity price.

CAPITAL ADDITIONS

Budgeted 2012 and historical capital expenditures are summarized below.

	\$000's					
	Test Year 2012	NSP 2011	2012/2011 Difference	Actual 2010	Actual 2009	Actual 2008
Additions inc. OH	\$4,146	\$4,001	\$145	\$1,525	\$5,743	\$6,726
Less OH	(1,038)	(1,046)	8	(1,471)	(1,710)	(1,994)
Net	\$3,108	\$2,955	\$153	\$54	\$4,033	\$4,732

The following identifies significant capital projects planned to be carried out in 2012.

Major 2012 Capital Projects	Budgeted Cost Excluding Overhead
Tunnel Rehabilitation at MP 245	\$364,000
Paint Gitnadoix East Bridge	113,000
Unspecified mainline repairs	184,000
Building Improvements	68,000
Meter replacements	245,000
Replace Obsolete Actuators	145,000
Update mosaics with current air photos	72,000
New/replacement tools and equipment	162,000
Replace Obsolete RTU's	144,000
New/Replacement Services	126,000
Replace Obsolete Handheld Data Devices	173,000
Mobile Equipment	396,000
Work Equipment	206,000
Total	\$2,398,000

The specific items mentioned above account for approximately 77 percent of the total capital expenditures forecast for 2012, excluding overhead. A number of minor capital projects are also budgeted to ensure PNG continues to provide its customers with safe, reliable and secure gas delivery service in 2012. Further details about the major capital projects in 2012 are provided in the following pages.

Tunnel Rehabilitation at MP 245 (\$364,000)

The tunnel is located at MP 245 approximately 30 kilometres east of Terrace on the east bank of the Copper River. The tunnel is approximately 120 metres long and cuts through a steep rock ridge and was constructed by drill and blast techniques. It was constructed as a pipeline route revision to avoid the Copper River channel undercutting a narrow flood plain section. Both tunnel portals are located in rock below steep slope sections. The tunnel has nominal dimensions of about 2.4 metre by 2.4 metre with vertical sidewalls and a flat ceiling. A geotechnical assessment of the tunnel was completed to ensure it could continue to function as designed. The assessment provided the basis for estimating the location and type of additional support required to ensure long term stable operation.

The tunnel requires rehabilitation involving an estimated 34 rock bolts and 55 square metres of shotcrete. The sections requiring additional support are in shear zones with poor quality, closely fractured rock and reduced strength. Improving support in shear zone areas requires a combination of both rock bolts and shotcrete. Scaling of loose rock is required prior to installation of additional rock bolts and shotcrete. Installation of adequate sidewall support in shear zone areas is required to prevent further sidewall failures. The \$364,000 estimated cost of the tunnel rehabilitation is based on a quote received from an experienced tunnel contractor who completed similar (although far more extensive) work at the Gitnadoix Tunnel.

Paint Gitnadoix East Bridge (\$113,000)

The original section of bridge over the Gitnadoix River is approximately 174 meters long and was constructed in 1999. During its original installation the structure was painted to help preserve its structural integrity. The paint coating has now reached the end of its useful life and must be replaced as significant rust is now appearing. This project will include the sandblasting of the structure followed by the application of Fusion Bond Epoxy coating.

Unspecified Mainline Repairs (\$184,000)

Right-of-way problems resulting from erosion, river and creek flooding or other unanticipated problems must be taken care of immediately to ensure reliability of service. Where this work requires pipe replacement or the reinforcing of river crossing protection or other system betterment, the cost of this activity is capitalized. The five year average (2006-2010) expenditure for this type of work is \$230,000, and in 2011 to the end of October expenditures have been \$191,000. PNG considers the provision for 2012 to be a reasonable estimate of the cost of this unplanned and unforeseeable work.

Building Improvements (\$68,000)

The replacement of windows in a portion of the Terrace operations centre (\$17,000), improved pipe storage racks (\$20,000) and the stabilization of the ground material at the Burns Lake construction centre (\$14,000) are the three largest components of this category of expenditures. The remaining expenditures are a variety of smaller items relating to office lighting replacements and security improvements.

Meter replacements (\$245,000)

Historically the meter testing and re-verification process has been utilized to minimize the life cycle cost of the meters while ensuring compliance with the accuracy requirements established in the Electricity and Gas Inspection Act. However, the useful life of a meter is not infinite and ultimately they must be replaced as they become no longer economical to re-build. The amount of meters which require replacement rises as the average age of the meters in service increases. The 2012 budget for replacing meters which are not suitable for repair is \$228,000. New incremental meters also need to be obtained at an estimated cost of \$17,000.

Replace Obsolete Actuators (\$145,000)

The reliable operation of the actuators for the mainline valves located at compressor stations R1 and R3 are imperative for the safe operation of the system. The current actuators were originally installed in 1968 and although they have been maintained ever since to ensure their reliable operation this is no longer possible. These actuators are now obsolete and equipment vendors no longer carry replacement parts.

Update Mosaics with Current Air Photos (\$72,000)

In 2012 a portion of the existing Mosaic drawings of the transmission system will be updated using current air photography that was acquired recently. The current version of the Mosaic drawings utilize air photography that was taken in 1970 and no longer accurately represents the area.

New Replacement tools and equipment (\$162,000)

There are a variety of minor components that are included in this area. The two single largest items are a gas detector to be used for completing leak survey work (\$26,000) and a flange torquing tool (\$20,000), the other significant items are instruments requiring replacement – i.e. line locators, gas surveyors, etc. (\$47,000).

Replace Obsolete RTU's (\$144,000)

The ability to be able to reliably communicate with various components of the system is a critical factor in the ongoing safe and reliable operation of the transmission system. At a variety of locations PNG has Remote Terminal Units (RTU's) which are a key part of this process which have now reached the end of their useful life. Reliability of these RTU's is dropping and replacement parts and software are no longer available from vendors creating an unsustainable operating situation. This project will replace 10 of these units in 2012.

New/Replacement Services (\$126,000)

The forecast 2012 expenditure in this area includes installing new service facilities, relocating or replacing existing facilities to ensure their continued safe operation and removing obsolete underground mechanical fittings to prevent their failure which would result in an unplanned release of gas.

Replace Obsolete Handheld Data Devices (\$173,000)

The current model of handheld devices used to gather meter reading data was first utilized across the company in 1992. PNG has been advised by the vendor that this model will no longer be supported commencing January 1, 2013 so this project will ensure the replacement of these devices with the current fully supported model. Failure to proceed with this update has the potential to seriously impede PNG's ability to gather meter reading data in a timely and accurate manner.

Mobile Equipment (\$396,000)

Nine replacement vehicles will be acquired during Test Year 2012 all of which meet the replacement criteria of 7 years or 160,000 kms. Five of the vehicles are three-quarter ton trucks and four are in the half ton pick-up category.

Work Equipment (\$206,000)

The forecast expenditure for work equipment in 2012 includes the acquisition of a road boring machine (\$112,000) and the replacement of a 1991 rubber tired backhoe with a smaller mini excavator (\$67,000) as well as the replacement of two 7 year old snowmobiles (\$27,000).

PNG agreed under NSP 2011 to include a Table in its 2012 revenue requirements application in the format set out below.

Plant in Service Additions Account Details 2012

Major 2012 Capital Projects (larger than \$50,000)	Budgeted Cost Excluding Overhead	Budgeted Cost Including Overhead	Plant in Service Account #
MP 245 Tunnel Rehabilitation	\$364,000	\$581,000	465
Paint Gitnadoix East Bridge	113,000	181,000	465
Unspecified mainline repairs	184,000	294,000	465
Building Improvements	68,000	68,000	482
Meter replacements	245,000	245,000	478
Replace Obsolete Actuators	145,000	232,000	466
Update mosaics with current air photos	72,000	115,000	465
New/replacement tools and equipment	162,000	162,000	486
Replace Obsolete RTU's	144,000	230,000	465
Services	126,000	201,000	473
Distribution main replacement	80,000	128,000	475
Replace Obsolete Handheld Data Devices	173,000	173,000	487
Mobile Equipment	396,000	396,000	484
Work Equipment	206,000	206,000	485
Cut-outs from ILI Digs	51,000	81,000	465
Other	579,000	852,000	
Total	\$3,108,000	\$4,146,000	

PNG also agreed under NSP 2011 to include in its 2012 revenue requirements application a Table showing budgeted 2011 capital additions compared to actual 2011 capital additions. This Table will be filed when PNG files its year end 2011 update to this Application. The update is expected to be filed in late February 2012 or early March 2012.

NON-PENSION POST RETIREMENT BENEFITS AND PENSION PLANS

The following discusses the rate base treatment proposed by PNG in respect of non-pension post retirement benefits (“NPPRB”) and Company pension plans.

Non-Pension Post Retirement Benefits Plan Expenses and Funding

Prior to 2004, the Company recovered in its rates actual NPPRB paid. By year end 2003, the consolidated unfunded liability of the Company’s NPPRB plan was \$4.7 million. In response to the growing accrued obligation, PNG requested and the Commission approved, recovery of the current service cost portion of its NPPRB plan expense in addition to its actual payments of NPPRB commencing in 2004. The Commission’s approval was conditioned on PNG creating a trust structure into which the current service cost portion of the NPPRB plan expenses recovered in rates had to be deposited. PNG requested Commission relief from this condition since the only structure available was a Canada Revenue Agency (“CRA”) approved retirement compensation arrangement (“RCA”) trust where each contribution to the RCA trust had to be matched with an equal remittance to a refundable tax account with CRA. Since no interest or other return was paid on the refundable tax account, the return on the NPPRB funds collected in rates was significantly less than the effective return which would have been earned by PNG’s customers had the Commission approved its request to credit the cumulative after-tax funds collected against the Company’s rate base. The Commission denied PNG’s request and the NPPRB RCA trust was created.

Effective January 1, 2009, the AcSB removed the temporary exemption providing relief to entities subject to rate regulation from the general requirements regarding recognition and measurement of assets and liabilities arising from rate regulation. To comply with this change in accounting standard, in 2009 PNG recognized the full liability related to its NPPRB plan expenses, with the offsetting entry made to establish a regulatory asset. At the end of 2010, PNG’s consolidated unfunded liability for NPPRB was \$5.4 million.

As a result of these factors, PNG applied to commence recovering the full NPPRB expense in rates to customers in its 2011 revenue requirements application. PNG also proposed that the current service portion of the NPPRB expense continue to be contributed to the RCA but that the remainder of the after-tax amount of the non-cash expense (i.e. the NPPRB expense recovered in excess of the 2011 cash cost of retiree non-pension benefits) be recognized as a credit to rate base. Through the NSP 2011 settlement process, PNG obtained approval to commence recovering the full NPPRB expense in rates, however, the NSP 2011 settlement also provided that PNG would contribute the full amount of the non-cash expense to the RCA. The RCA trust account has a forecast balance of \$681,000 at December 31, 2011 with a similar amount being credited in the CRA refundable tax account.

With the conversion to US GAAP reporting commencing January 1, 2012, the estimated unamortized transitional obligation of \$861,000 under its NPPRB plan at December 31, 2011 will be debited to the Company's retained earnings, all else remaining the same. This is a result of the full accrual accounting methodology for NPPRB's being adopted earlier under US GAAP than Canadian GAAP such that transitional obligations had to be fully amortized by the end of 2011 under US GAAP while under Canadian GAAP they were being amortized through to the end of 2018. PNG requests that the Commission explicitly approve recognition of a regulatory asset equal to the unamortized transitional obligation at the end of 2011 in order to offset the retained earnings impact of the conversion to US GAAP. PNG also proposes to fully amortize this regulatory asset January 1, 2012, with a concurrent equal and offsetting amortization of its regulatory deferred income tax liability. Further, PNG also proposes to fully amortize the net unfunded liability associated with its NPPRB plans in the same manner. By doing so, PNG's rate base will be unaffected and the complications of developing an appropriate amortization methodology for each of these independent items will be avoided which in turn will reduce the ongoing administration required for a growing number of regulatory accounts. Below are the details of the proposed amortization of these accounts and the impacts on the Company's consolidated balance sheet as well as the divisional rate base impacts.

January 1, 2012 Amortization Proposal – NPPRB
 Consolidated Financial Statements

	Debit	Credit
Amortization of NPPRB regulatory asset		\$2,496
Amortization of FIT on NPPRB regulatory asset	\$624	
Amortization of NPPRB transitional obligation regulatory asset		861
Amortization of FIT on NPPRB transitional obligation regulatory asset	215	
Amortization of deferred income tax regulatory liability – PNG-West	2,017	
Amortization of deferred income tax regulatory liability – PNG(N.E.)	501	

Example

PNG Consolidated Balance Sheet at January 1, 2012
 (\$000s)

	Prior to Proposed Amortization	Following the Proposed Amortization
<u>Assets</u>		
NPPRB regulatory asset	\$ 2,496	\$ -
Unamortized NPPRB transitional obligation regulatory asset	861	-
All other assets	<u>234,343</u>	<u>234,343</u>
	\$237,700	\$234,343
<u>Liabilities</u>		
NPPRB funded status	\$ 5,744	\$ 5,744
Deferred income tax regulatory liability – PNG-West	9,862	7,845
Deferred income tax regulatory liability – PNG(N.E.)	826	326
FIT on NPPRB funded status	(1,436)	(1,436)
FIT on NPPRB regulatory asset	624	-
FIT on NPPRB transitional obligation regulatory asset	216	-
Retained earnings	76,300	76,300
Accumulated OCI	(1,790)	(1,790)
All other liabilities and shareholder equity	<u>147,354</u>	<u>147,354</u>
	\$237,700	\$234,343

PNG-West Division 2012 Rate Base
 (\$000s)

	Prior to Proposed Amortization	Following the Proposed Amortization
Deferred income taxes	(\$9,362)	(\$7,345)
Historical unrecovered NPPRB expense requiring amortization (net-of-tax)	1,506	-
NPPRB transitional obligation adjustment requiring amortization (net-of-tax)	511	-
After-tax balance net NPPRB liabilities	(2,017)	(2,017)
All other rate base items	142,567	142,567
	<u>\$133,205</u>	<u>\$133,205</u>

Fort St. John/Dawson Creek Division 2012 Rate Base
 (\$000s)

	Prior to Proposed Amortization	Following the Proposed Amortization
Deferred income taxes	(\$449)	(\$5)
Historical unrecovered NPPRB expense requiring amortization (net-of-tax)	325	-
NPPRB transitional obligation adjustment requiring amortization (net-of-tax)	119	-
After-tax balance NPPRB liabilities	(444)	(444)
All other rate base items	43,467	43,467
	<u>\$43,018</u>	<u>43,018</u>

Tumbler Ridge Division 2012 Rate Base
 (\$000s)

	Prior to Proposed Amortization	Following the Proposed Amortization
Deferred income taxes	(\$353)	(\$297)
Historical unrecovered NPPRB expense requiring amortization (net-of-tax)	41	-
NPPRB transitional obligation adjustment requiring amortization (net-of-tax)	15	-
After-tax balance NPPRB liabilities	(56)	(56)
All other rate base items	2,839	2,839
	<u>2,486</u>	<u>2,486</u>

PNG also proposes to commence winding up the RCA for its NPPRB plan. As noted above each contribution to the RCA trust has to be matched with an equal remittance to a refundable tax account with CRA and no interest or other return is paid on the refundable tax account. As a result, the return on NPPRB funds under the RCA trust structure is significantly less than the effective return which can be earned by PNG's customers when cumulative after-tax funds collected provide a credit to the Company's rate base.

Given that the beneficiaries of the RCA trust are PNG retirees, funds withdrawn from the trust can only be used to purchase benefits for retirees under the NPPRB plan and no immediate wind-up of the RCA trust is possible. In order to effect the proposed wind-up, PNG proposes that it does not contribute any NPPRB expense to the RCA trust in 2012 and commencing in 2013 that it use the RCA trust funds (with matching withdrawals from the refundable tax account) to pay the cash costs of retiree non-pension post-retirement benefits. Given that the regulatory approvals for the requested wind-up of the RCA trust structure are not likely to be obtained until sometime in 2012, PNG believes that deferring withdrawals from the RCA trust fund until 2013 will significantly simplify administration and accounting for this proposed change.

As noted earlier, PNG also proposes that the after-tax amount of the non-cash expense (i.e. the NPPRB expense recovered in excess of the 2012 cash cost of retiree non-pension benefits) be recognized as a credit to rate base.

Pension Plan Expenses and Funding

PNG is of the view that NPPRB and pension plans funding differences should be accorded equal rate base treatment.

At December 31, 2010 the Company recognized a pension asset, gross of related future income taxes, on its balance sheet of \$2.5 million on a consolidated basis with this asset expected to be \$3.4 million at the end of 2011. This amount represents the funding contributed to its pension plan, as required by legislation, in excess of the actuarially determined expense of its pension plan. As is considered appropriate by the Company, the actuarially determined expense has been recovered in rates. However, the plan contributions in excess of the expense have been funded by the Company with no compensation. PNG proposes in this Application to have the Company's after-tax pension asset recognized in rate base. The after-tax average pension asset proposed for inclusion in the PNG-West rate base in 2012 equals \$2.0 million (see Tab 2, Page 1, Line 15 and the supporting new schedule at Tab 2, Page 10, Line 19).

2012 FORECAST GAS DELIVERIES

The Test Year 2012 forecast of gas deliveries determines the projected margin PNG will receive from its customers during 2012 to pay the cost of serving those customers. The NSP 2011 gas delivery forecast is compared to the Test Year 2012 forecast in the table below. The numbers have been rounded for ease of reference. Decreases from NSP 2011 to Test Year 2012 are indicated by bracketing the figures.

Customer Groups	NSP 2011 compared to Test Year 2012	
	Changes in Forecast Deliveries (GJ)	Changes in Forecast Margin (\$)
Residential ⁽¹⁾	11,300	102,800
Granisle	(480)	(3,100)
Commercial Sales ⁽²⁾	12,200	109,600
Commercial Transportation ⁽²⁾	29,500	287,700
Commercial Interruptible	(7,000)	(32,000)
Small Industrial ⁽³⁾	91,000	269,000
Rio Tinto Alcan	(111,200)	(332,400)
B.C. Hydro	0	0
Total	25,320	\$401,600

Notes

1. The margin change for residential customers reflects the combined impact of lower forecast deliveries and lower fixed monthly rate margin due to a decline in number of customers.
2. The commercial sales and commercial transportation customer categories include both small and large commercial customers.
3. The small industrial customer group includes the seasonal off-peak, NGV, small industrial firm sales and small industrial transportation service customers.

Residential Firm Sales Customers

Forecast deliveries to the residential customer class are based on an increase in the forecast use per account from 66.7 GJ/year used under NSP 2011 to 68.0 GJ/year for Test Year 2012. The 68.0 GJ/year figure is the mid-point between forecast normalized use per account in 2011 of 70.9 GJ/year and the linear trend of 65.1 GJ/year. The forecast number of customers in 2012 is based on the number of customers being served as of the preparation of this Application. The average customer count for 2012 is lower than used to set rates under NSP 2011. The projected margin increase in 2012 of \$102,800 reflects the combined impact of the higher forecast use per account and the reduced number of customers.

Small Commercial Firm Sales Customers

Forecast deliveries to the small commercial firm sales customers are increasing by approximately 15,700 GJ. This accounts for the majority of the increase in forecast margin and deliveries to the combined small and large commercial firm gas sales customer categories. The use per account for small commercial sales customers has increased from 308.9 GJ/year under NSP 2011 to 319.7 GJ/year in 2012.

Granisle Propane Deliveries Forecast

The Test Year 2012 forecast of propane deliveries is 8,869 GJ a reduction of 478 GJ compared to the NSP 2011 forecast of 9,347 GJ. This reflects the fact 2011 deliveries have declined relative to the forecast used under NSP 2011. The trend to lower propane consumption in Granisle continues.

Other Core Market Customers

The following compares projected Test Year 2012 and NSP 2011 forecast deliveries for large commercial firm sales, small and large commercial transport, large commercial interruptible, seasonal off-peak and NGV customers.

	(GJ's)		
Customer Class	Test Year 2012	NSP 2011	Difference
Large Commercial Sales	40,500	44,000	(3,500)
Commercial Transport	301,842	272,313	29,529
Commercial Interruptible Sales	24,500	31,500	(7,000)
Seasonal Off-Peak Sales	16,800	16,400	400
NGV Sales	11,050	12,250	(1,200)
Total	396,704	378,474	18,230

The above forecasts for 2012 are based on a review of historical deliveries to these customer classes and expected use in 2012 based on discussions with some of the customers.

Small Industrial Customers

The following compares projected Test Year 2012 and NSP 2011 forecast deliveries to PNG's small industrial customers, comprised of firm sales and firm/interruptible transportation service customers.

	(GJ's)		
Customer Class	Test Year 2012	NSP 2011	Difference
Firm Sales	183,800	180,800	3,000
Transportation	617,960	529,100	88,860
Total	801,760	709,900	91,860

The projected 2012 deliveries are based on the forecasts obtained from PNG's small industrial customers. The large increase in transportation service volumes is primarily due to the Conifex sawmill in Fort St. James. Gas deliveries in 2011 have exceeded the forecast used under NSP 2011. The higher level is expected to continue in 2012. Deliveries to Conifex are included under the industrial customer deliveries deferral account due to the fact deliveries to Conifex have varied greatly from year to year.

Large Industrial Customers

The projected Test Year 2012 deliveries to the PNG’s large industrial customers are set out below in comparison to NSP 2011 delivery forecasts.

Customer	Test Year 2012	NSP 2011	Difference
Rio Tinto Alcan	741,000	852,220	(111,220)
BC Hydro	24,000	24,000	0
Total	765,000	876,220	(111,220)

Rio Tinto Alcan has provided PNG with a forecast of deliveries in Test Year 2012 that reflects lower deliveries having regard to the impact on their smelter operations of their modernization project activities. PNG is using the figures provided by Rio Tinto Alcan.

The BC Hydro deliveries forecast is based on the assumption BC Hydro will not be operating its Prince Rupert generating station for base load or emergency purposes during 2012. The 24,000 GJ figure is consistent with historical deliveries during years when BC Hydro only operates its generating station to keep it in a ready to operate mode in case of an emergency.

Company Use Gas Requirements

PNG uses gas for a number of different purposes to operate its pipeline system. Over 50 percent of Company use gas is used as fuel in PNG’s compressors located along the transmission system. Other sectors of Company use gas, such as station heating and office and shop heating are expected to maintain levels comparable to recent years. The unaccounted for gas component of Company use gas has been set at zero percent for 2012, the same figure used under NSP 2011. The foregoing is based on the assumption a UAF volume deferral account will continue in 2012 with a UAF loss cap of 1 percent. PNG would be required to obtain Commission approval to record the impact of UAF losses above 1 percent.

DISCUSSION OF RATE MATTERS

The following section explains the methodologies used by PNG to calculate the rates PNG is asking the Commission to approve effective January 1, 2012. The material underpinning the rate calculations is provided under Tab Rates of this Application.

Allocation of Revenue Deficiency

The Table entitled “Summary of Gas Delivery Charge Proposed Rate Changes Effective January 1, 2012” under Tab Rates shows the allocation of the 2012 revenue deficiency to PNG’s customers using normalized gross margin as the allocator.

The small commercial sales and transportation service customers are treated as one customer class for the purposes of allocating the revenue deficiency to those customers. This allocation principle is also applied to the large commercial sales and transportation service customers and has been applied to the small industrial sales and transportation service customers for several years.

The recovery of the portion of the revenue deficiency allocated to BC Hydro based on their total projected gross margin is split between the monthly demand charge and the interruptible delivery rate. The interruptible gas delivery rate increase shown for the other industrial customers applies to the delivery of gas to BC Hydro. PNG determines how much of the BC Hydro revenue deficiency is forecast to be recovered through the delivery of their forecast gas deliveries. This amount is deducted from the total revenue deficiency allocated to BC Hydro and the balance is divided by 12 months and added to the BC Hydro monthly demand charge. The result of this calculation is shown on the “Summary of Proposed Rates Effective January 1, 2012”.

Derivation of Forecast Test Year Gas Deliveries and Gross Margin

PNG has included under Tab Rates detailed schedules showing the calculation of the forecast Test Year 2012 gas deliveries using the parameters discussed earlier. The forecast uses per account for the residential and small commercial customers is applied against their forecast average number of customers to show the calculation of annual deliveries to these customer classes. The calculation of deliveries to the other customers is also shown in this section.

Similarly, the derivation of projected margin recovery by customer class in Test Year 2012 using 2011 rates is shown on schedules included in Tab Rates. There may be some small differences between the detailed schedules showing the calculation of forecast margin and the summary figures shown in other sections of this Application due to rounding that occurs when utilizing large spreadsheets to calculate gross revenue, delivery margin and gas supply costs.

RSAM Rate Rider

A Table is provided under Tab Rates to show the projected year-end 2011 RSAM balance and the derivation of the RSAM rider assuming three year amortization of the projected balance. This RSAM rider calculation will be updated to reflect the most recent information available when the final 2012 regulatory schedules are filed with the Commission to set rates effective January 1, 2012. Consequently, the calculated RSAM rider at year end 2011 is indicative only. However, PNG is requesting that the interim rates effective January 1, 2012 reflect the forecast RSAM rate rider as PNG does not expect the forecast balance will change to any degree by year end 2011.

2012 Gas Supply Cost Charge and GCVA Riders

The January 1, 2012 gas supply cost recovery rates shown in the “Summary of Proposed Rates Effective January 1, 2012” are based on the cost of gas shown at Tab 1, Page 1, Line 16. The forecast cost of gas in 2012 was calculated using PNG’s gas cost flow through model updated to reflect the 2011/2012 gas supply and price arrangements entered into by PNG with its gas suppliers and the forecast gas prices from a recent forward gas price strip set forth under Tab Rates.

PNG’s revenue requirement model is designed to show the recovery of forecast gas supply costs on a flow through basis. In other words, the net margin (i.e. gross revenue less forecast cost of sales) will be the same regardless of what projected gas supply prices are used by PNG to calculate gas supply costs. PNG’s fourth quarter 2011 gas supply cost report to the Commission, to be filed in early December 2011, will contain proposed gas supply cost recovery rates and GCVA rate riders that will differ from the indicative January 1, 2012 rates shown in this Application.

A Table under Tab Rates entitled “Derivation of Test Year Forecast Gas Supply Cost” shows the derivation of the cost of sales figure shown at Tab 1, Page 1, Line 16. The forecast deliveries by customer class times the indicative gas supply prices generates the cost of sales figures for each customer class.

Determination of 2012 Unit Company Use Gas Cost Rate

The 2012 projected cost of Company use gas is calculated as part of the cost of gas calculation previously described and the quantity of gas PNG expects to purchase for Company use. The most significant portion of Company use gas is the requirement for fuel to operate PNG’s compressors. The calculation of the indicative 2012 unit Company use gas cost recovery rate is shown on a schedule under Tab Rates. PNG divides the forecast cost of Company use gas by total deliveries to all customers to determine the Company use gas cost recovery rate to be embedded in the delivery rates. The figure provided in the Company use gas cost table under Tab Rates is indicative at this time as the Company use gas delivery rate effective January 1, 2012 will be set by the Commission as part of the review of PNG’s fourth quarter 2011 gas cost report to the Commission.

Bill Comparison at Current Rates and Proposed Rates Effective January 1, 2012

PNG includes under Tab Rates a comparison of the projected annual gas bills for residential and small commercial customers using current rates effective October 1, 2011 and rates proposed effective January 1, 2012. The bill comparison focuses on the delivery rate increase that is required to recover the forecast 2012 revenue deficiency by keeping the gas supply cost related rates unchanged pending the Commission’s review of PNG’s fourth quarter 2011 gas cost report.

The average rate increase for residential customers compared to October 1, 2011 rates is estimated to be 2.6 percent on the delivery charge component of rates or \$23 per year for an average customer. The projected average bundled rate of \$19.004/GJ is \$5.649/GJ lower than the electricity equivalent rate of \$24.653/GJ assuming a 90 percent gas to electricity efficiency factor and using the trailing block electricity rate applicable under the residential inclining block rate structure.

The small commercial customer average rate increase is estimated to be 2.5 percent on the delivery charge component of rates or \$85 per year for an average customer. The projected average bundled rate of \$16.306/GJ is \$6.271/GJ lower than the electricity equivalent rate of \$22.577/GJ assuming a 90 percent gas to electricity efficiency factor.

Applied for Rates are Just and Reasonable

PNG submits that the rate increases applied for under this Application are just and reasonable based on long standing regulatory principles applied by the Commission in the exercise of its rate setting responsibilities under the Act. In preparing each revenue requirements application, PNG's senior management team keeps in mind the Commission's requirement to balance the need of PNG to recover its reasonable and prudent costs with the need to ensure ratepayers are charged fair and reasonable rates. PNG considers rates are fair and reasonable if the following criteria are met:

1. Rates are set at a level that provide sufficient margin to enable PNG to provide safe, reliable and secure gas delivery service to its customers.
2. PNG's financial integrity is maintained which includes being able to meet financial covenants under outstanding debt instruments and to retain an investment bond rating.
3. PNG has taken prudent steps to manage its costs to ensure there are no unnecessary or unreasonable costs included in the applied for cost of service.
4. PNG's rates are competitive with other energy sources and thereby provide a reasonable probability of preventing declining recovery of margin due to customers converting to alternative energy sources or reducing gas consumption.
5. PNG's shareholders have the opportunity to earn a reasonable rate of return on their equity investment in PNG.

Earlier in this Application PNG explained in detail the reasons why operating, maintenance, administrative and general expenses in 2012 will be higher than budgeted under NSP 2011. The level of costs will reasonably ensure that PNG can provide safe, reliable and secure gas delivery service at an appropriate level. PNG has taken prudent steps to manage its 2012 budgeted costs and submits there are no unnecessary or unreasonable costs included in its budgeted 2012 costs.

With respect to competitiveness of rates, PNG's bundled residential and small commercial rates are forecast to be less than the equivalent electricity rates. PNG acknowledges the fact that much lower gas purchase costs throughout 2011 have played a significant role in keeping bundled gas rates competitive with electricity notwithstanding PNG's relatively large delivery charges applicable to its residential and commercial customers. As was stated in 2006, PNG's senior management team is monitoring competitiveness of its rates on an ongoing basis and will be prepared to make an appropriate application to the Commission to reduce customer rates should increases in gas commodity charges result in non competitive bundled gas rates. As noted at page 27 of Decision 2006, this would be done if PNG determined that "lower customer rates would improve cost recovery and prevent PNG's recoverable margin from declining".

In summary, the rates applied for under this Application are just and reasonable having regard to the regulatory principles the Commission applies when determining whether rates are just and reasonable pursuant to the Act.

DEMAND SIDE MANAGEMENT

PNG's position on the appropriateness of additional DSM activity has not changed from the position set out in its 2011 revenue requirements application narrative. PNG continues to believe that its marginal retail prices are generally well in excess of marginal cost including all externalities. This situation is, in and of itself, most effective in promoting DSM, as evidenced by PNG's experience with declining use per customer. PNG also continues to believe that the administrative costs associated with DSM programs would simply exacerbate the already inefficient and inappropriate relative price signals between natural gas and electricity by further increasing PNG's prices through a higher cost of service. Without a doubt, natural gas is utilized much more efficiently in direct space and water heating applications than it is by first converting it to electricity. It is this latter situation, where the marginal source of electricity is from gas fired generation either in B.C. or imported from the U.S. with resale of that electricity significantly below its marginal cost that has created such distorted price signals and an inefficient end-use energy market in B.C. However, PNG acknowledges that the new inclining electricity block rate has addressed the electricity relative price signal issue to a certain extent. For all the reasons noted above, PNG proposes that it dedicate limited resources to DSM activity at the present time.

IDENTIFIED SERVICE QUALITY METRICS

The Commission directed PNG under Order G-192-11 to report on five key service quality metrics commencing with the 2012 revenue requirements application. The requested data is provided the following Table.

PNG-West Identified Quality Service Metrics

<u>Description</u>	<u>2011 YTD*</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>
Number of emergency calls	368	446	510	516
Average response time	17.5 mins	18 mins	20 mins	18 mins
Number of calls with response time over 40 mins.	37	44	70	47
No. of Underground leaks	6	9	7	5
No. of Reportable Environmental Incidents	0	2	0	1
Lost Time Injury Frequency Rate	0	0	1.37	0
Customer Complaints to Commission**	N/A	6	10	2

*January to October 31, 2011

**Information reflects Commission's March 31 fiscal year end (i.e. data for 2010 is from April 1, 2010 to March 31, 2011)

OVERVIEW OF CONVERSION TO US GAAP

On October 6, 2011, PNG received Commission approval to use US GAAP for regulatory accounting and reporting purposes for the period January 1, 2012 to December 31, 2014 (see Order G-168-11). This Application has been prepared having regard to US GAAP. Section 5 of Order G-168-11 stated this Application “should include a section on the ‘Overview of Conversion to US GAAP’”. The following responds to that direction.

PNG prepared its 2011 revenue requirements application under Canadian GAAP (“CGAAP”) but implemented a number of accounting changes that would enable it to align with its financial reporting requirements under IFRS in anticipation of the initial conversion date of January 1, 2012 and provision of comparative figures for 2011.

The following table summarizes areas that were anticipated to have material impacts arising on the transition to IFRS. The table details key changes proposed and which changes were addressed in NSP 2011. The last column notes any US GAAP implications reflected in this Application.

	Issue	Matters raised in 2011 RR Application	NSP 2011– IFRS compliant changes	2012 Application – US GAAP
Property, plant & equipment				
	Depreciation	Depreciation study completed – straight line over remaining useful lives	Implemented	Same
	Timing of Depreciation	Commencement of depreciation when asset is available for use.	Implemented & reversed – deferral account in 2011	Depreciation commences beginning of following year
	Overhead capitalization	Overhead study completed – directly attributable costs	Implemented	Same
	Deactivated assets	Reallocated from deferral account and included in PP&E	Implemented	Same
	Retirements	Residual NBV balances on gains/losses from retired assets.	Reallocated from plant to deferral account.	Deferral account – commence amortization
	Plant Gains and losses	Gains / losses on future retirements	Deferral account	Same

	Major inspections	Capitalization of non physical components of plant	Not addressed in 2011	No change from RRA
	Decommissioning liabilities	Recognition of decommissioning obligations.	Not recorded	Same
	Presentation	Jan 1, 2011 NBV as deemed cost – accumulated depreciation set to nil.	Applied but not accepted – gross presentation	Gross presentation
Customer contributions				
	Initial contribution	Consider revenue recognition	Not addressed in 2011	No change from RRA
	Presentation	Gross vs. net presentation	Not addressed in 2011	No change from RRA
Income taxes				
	Future rates when temporary difference reverse	Measurement of FIT / DIT on net of tax deferral accounts	Not addressed in 2011	No change from RRA
	Presentation	Net of tax presentation not permitted		
	Uncertain tax provisions	Recording of uncertain tax provisions	Not addressed in 2011	None recorded
Employee benefits: defined benefit plans – pension & non pension				
	Transitional balances arising upon conversion	Unamortized net actuarial gains and losses	Reset to zero through RE -Not addressed in 2011	Reallocated to OCI – recovered through annual expense
		Unamortized transitional obligation	Reset to zero through RE -Not addressed in 2011	Offset against legacy DIT balance
	Regulatory asset	Regulatory asset raised representing the difference between rates calculated on a cash basis and actuarial balance.	Not addressed in 2011	Offset against legacy DIT balance
	Income statement policy	Recognition of actuarial gains and losses through income statement	Not addressed in 2011	Corridor method

- **Rate regulated accounting is permitted under US GAAP whereas, it is currently unavailable under IFRS.**

Unlike IFRS, US GAAP allows the balance sheet recognition of regulatory deferral accounts. Under IFRS which does not allow the recognition of regulatory assets nor liabilities, PNG was going to maintain two sets of accounting books: one for external reporting and one for rate setting purposes. Under US GAAP, PNG will be able to use one set of books for both purposes.

- **Depreciation calculation:**

In its 2011 revenue requirements application, PNG determined its depreciation expense using the remaining useful lives of its assets based on the Depreciation Study prepared by an external consultant and management's best estimates. This basis is also acceptable under US GAAP. Therefore, PNG will prepare depreciation expense on the same basis as in 2011 except for the starting date of depreciation. Under Canadian GAAP in anticipation of IFRS, PNG had proposed commencing depreciation once the asset was available for use. Historically, PNG started depreciation at the commencement of each year. In this Application, PNG has returned to its practice of commencing depreciation on new additions in the following year for ease of administration and to accurately forecast total depreciation expense. PNG had included an estimate of depreciation for 2011 additions of \$103,000 for both PNG and PNG(N.E.) in the 2011 revenue requirements applications. As note earlier in the Application, PNG is seeking Commission approval to set up credit deferral accounts to record this 2011 additions depreciation and amortized the accounts to the PNG-West and PNG(N.E.) 2012 costs of service for rate making purposes, accordingly.

- **Capitalized Overheads**

In its 2011 revenue requirements application, PNG completed and filed an overhead capitalization study that is compliant with IFRS. Under IFRS, only directly attributable employee costs are included in capital. This methodology is also acceptable under US GAAP. Accordingly, PNG this Application uses the same methodology as applied in the 2011 revenue requirements application.

- **PP&E presentation**

Upon conversion to IFRS, PNG elected to use the January 1, 2011 net book value as deemed cost for its rate regulated assets. This in effect resets the cost to the net book value and accumulated depreciation to zero. For the 2011 revenue requirements application, PNG was not allowed to use this net book value presentation. In this Application PNG has continued to use the historic gross presentation format. This has no impact on depreciation expense.

- **Employee benefits: Defined benefit pension and Non pension plans**

Under IFRS, PNG elected to reset its unamortized net actuarial gains and losses to zero with an offsetting adjustment to retained earnings. In its 2011 revenue requirements application PNG did not include any adjustment for this amount as PNG planned to deal with this matter in this Application.

Under US GAAP, the net actuarial gains/losses will be moved from the carrying value of the defined benefit pension and non pension plans to Other Comprehensive Income (OCI) which is a component of equity. The amount of these balances determined under US GAAP is similar to the CGAAP balance.

US GAAP allows the use of corridor method in the recognition of actuarial gains and losses into income. This is the same methodology that PNG has used under CGAAP. The net unamortized actuarial gains and losses in OCI will be amortised into income through the annual expense as determined by the corridor methodology. Accordingly, no significant difference is expected to result to the annual cost of service calculations from converting to US GAAP.

Under IFRS, it was proposed that the corridor method would no longer be available as a policy selection for income recognition of actuarial gains and losses. It is unclear how this would have affected future revenue requirements applications except that it would have likely increased reconciling differences between rate filings and external financial statements.

Impact of US GAAP:

PNG has identified the following areas where there is an impact of adopting US GAAP:

- **Defined Benefit Pension and Non Pension plans**

There are three main components of accounting for defined benefit plans: the liability, the assets, and actuarial gains and losses. The liability represents the present value of the expected future payments required to settle the obligation resulting from employee service. The measurement of the liability will be same under CGAAP and US GAAP.

Under US GAAP, the plan assets on the balance sheet are measured at fair value. Under CGAAP, the plan assets are measured at a market related value that allows for changes in fair value to be recognised over five years.

US GAAP requires that the measurement date is at the financial reporting date which would be December 31st for PNG. CGAAP allows a measurement date up to three months prior to the reporting date provided it is applied consistently year over year. PNG has been using September 30th as its measurement date. The net residual adjustment to Retained Earnings due to change in measurement date is very small and no adjustment is proposed.

The significant differences between CGAAP and US GAAP arise from the treatment of the actuarial gains and losses.

Balance sheet

Under US GAAP, the funded status is the carrying value of the pension and non pension plans. The funded status is the difference between the liability and the fair value of the assets. The net actuarial gains/losses are presented in OCI. Under CGAAP, the net actuarial gains/losses are included with the funded status and presented as either a net asset or liability.

Historically, these amounts have not been included in PNG's regulatory books, however, as described in section Non-Pension Post Retirement Benefits and Pension Plans, PNG is proposing that the after-tax average pension asset be recognized in rate base.

PNG will adjust its equity calculations for the unamortized net actuarial gains and losses.

Income Statement

As discussed, US GAAP allows the use of the corridor method to recognise actuarial gains and losses into income. PNG uses the corridor method under CGAAP and will continue to use it upon its adoption to US GAAP.

- **Non pension employee plans**

Significant differences result from the US GAAP conversion for the non-pension post-retirement plans:

- **Historic difference between cash and actuarial determined basis:**

Up to 2011, PNG recovery through rates of its non pension plan was on a cash basis and not the full actuarial determined amount with a resulting difference of \$2.5 million. Accordingly, under CGAAP, PNG has recognized a regulatory asset of \$2.5 million. PNG proposes to record this \$2.5 million difference in a deferral account and immediately amortize it during 2012 by offsetting the impact of this amortization through a drawdown of the deferred income taxes balance.

- **Foregone amortization lost on US GAAP conversion:**

In addition, the conversion to US GAAP has raised a \$0.9 million difference resulting from the different historic conversion dates of US GAAP and CGAAP. Upon the adoption of accounting standards for defined benefit plans, a transitional obligation was raised representing the difference between the carrying value before and after adoption. In US GAAP, these accounting standards for post-employment plans were introduced in 1995 while PNG adopted these accounting standards in 2002.

Upon the conversion to US GAAP, the transitional obligation is measured on the effective transition date of the US GAAP standard being 1995. Accordingly, under US GAAP this transitional obligation is fully amortised effective January 1, 2012 and its amortization will no longer be included in the annual expense. However, under CGAAP, there remains an unamortized balance that would have been amortized over the next seven years. PNG proposes to record this \$0.9 million in a deferral account and immediately amortize it during 2012 by offsetting the impact of this amortization through a drawdown of the deferred income taxes balance.

- **Uncertain tax positions**

US GAAP requires that companies measure and disclose uncertain tax positions, which may occur when a company takes positions on the treatment of items for tax purposes upon filing with tax authorities that may be challenged and possibly denied. PNG has completed an internal assessment of its tax positions, and while this assessment is still subject to audit, PNG does not expect to have any material adjustments as a result of this standard.

Cost of adopting US GAAP and IFRS

PNG has estimated a cost of \$400,000 to adopt US GAAP. These costs are reflected in the joint IFRS/US GAAP deferral account. PNG proposed earlier in this Application to amortize the balance in this deferral account over three years starting in 2012.

PNG incurred \$470,000 for its IFRS conversion. However, a significant amount of these costs were incurred for PP&E related matters such as a depreciation study, a capitalized overhead study and data conversion costs. These activities will be very beneficial to the US GAAP conversion process. This Application has been prepared using the depreciation and capitalized overhead studies.

Progress Report on US GAAP Transition Project

The US GAAP conversion project is on track. Areas of potential differences between Canadian GAAP and US GAAP were identified during the scoping phase. Memos have been prepared on all the significant accounting issues and have been reviewed by PNG's external auditors to ensure that PNG's assessments and proposed changes are appropriate. External technical consultants also assisted PNG in addressing the more complex accounting issues. PNG is now in the process of preparing an opening balance sheet at January 1, 2011, and draft financial statements reported in US GAAP for the three quarter-ends of 2011. These will be necessary for providing comparative information in the 2012 quarterly financial statements. The project team is also working on any required changes to processes in order to be able to report under US GAAP effective January 1, 2012.

Reconciliation of Canadian GAAP and US GAAP for 2012

PNG was directed to prepare a reconciliation of amounts reported for regulatory accounting to those amounts that would otherwise be reported under 2011 Canadian GAAP for the year ending December 31, 2012 to be included in its annual report and the 2012 RRA. As noted in the US GAAP application, the 2011 Canadian GAAP (Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook) will cease to exist at the end of 2011 as it will be replaced by IFRS. Assuming that for 2012, PNG continues to follow Part V of the CICA Handbook standards, PNG has identified two main differences between 2011 CGAAP and US GAAP:

- PNG would have continued to commence depreciation for capital additions when the asset is put into service (in anticipation of IFRS) which would have resulted in an increase in the consolidated depreciation expense of approximately \$37,000 under CGAAP compared to US GAAP.
- Accounting for defined pension plans and non-pension plans would have resulted in a consolidated benefits expense estimated to be \$52,000 higher under CGAAP than under US GAAP (based on 2011 estimates of the expenses under each GAAP).

As noted in the section Non-Pension Post Retirement Benefits and Pension Plans, PNG has proposed to record both the unamortized transitional obligation at the end of 2011 and the net unfunded liability associated with its NPPRB plans in a regulatory asset account and fully amortize this asset with a concurrent equal and offsetting amortization to its regulatory deferred income tax liability. The methodology proposed will have no impact on rate base nor on the 2012 revenue requirement.

Requirement for Further Periods Reconciliations

As noted in the previous section, there are no significant differences between the 2011 Canadian GAAP (Part V of the CICA Handbook) and US GAAP. As such, PNG respectfully requests that no further period reconciliations need to be provided in the future as PNG would need to incur additional actuarial costs (estimated to be between \$5,000 - \$10,000 annually) to provide the calculation of pension and non-pension expenses under 2011 Canadian GAAP.

COMMISSION ORDERS SOUGHT BY PNG

PNG is seeking the following Commission approvals under this Application:

1. Approval, effective January 1, 2012, on an interim basis pursuant to sections 58 to 61, 89 and 90 of the Act, of the delivery charges set forth under the heading “Proposed Rates January 1, 2012” as set forth in the table under Tab Rates entitled “Summary of Proposed Rates Effective January 1, 2012”.
2. Approval of the cost allocators and level of shared service cost recovery by PNG from PNG(N.E.) during 2012 as set forth in this Application for the purposes of determining the level of such costs to be recovered by PNG(N.E.) in its customer rates.
3. Approval of the Code of Conduct and Transfer Pricing Policy set forth under Tabs 6 and 7 of this Application.
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. In particular, PNG is seeking Commission approval of a new deferral account for 2011, to be amortized in 2012, called the 2011 depreciation adjustment deferral account.
5. Approve recognition of a regulatory asset equal to the unamortized NPPRB transitional obligation at the end of 2011 and a regulatory asset equal to the historical unrecovered NPPRB expense and to approve of PNG fully amortizing both these regulatory assets January 1, 2012, with a concurrent equal and offsetting amortization of its regulatory deferred income tax liability.
6. Approve the wind-up of the Retirement Compensation Arrangement (RCA) trust with Canada Revenue Agency (CRA), waive the requirement to contribute additional funds to the RCA commencing in 2012, and commence the use of the RCA trust fund to pay the cash costs of retiree Non-Pension Post-Retirement Benefits in 2013.
7. Approve the recognition of PNG’s after-tax pension asset in rate base and after-tax credit to rate base equal to the average amount of after-tax funds recovered in rates for NPPRB expense in excess of the amounts contributed to the RCA trust, refundable tax account or paid for retirees’ benefits.
8. 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.

9. Confirmation of the agreement in the NSP 2011 settlement to amortize the West Fraser Mills contract termination payment over the December 2011 to December 2013 period as a credit to the cost of service.
10. Approval to draw down \$1,000,000 of deferred income taxes as a credit to the income tax component of the Test Year 2012 cost of service.

Draft Commission Order

A draft Commission order is set out under Tab 8. The Order addresses PNG's request for approval of interim rates effective January 1, 2012 and sets out a proposed preliminary regulatory timetable with the dates to be determined by the Commission. The applied for rates would apply on an interim basis. Permanent rates effective January 1, 2012 would be set and billing adjustments would be made in the ordinary course based on the final rates approved by the Commission.

All of which is respectfully submitted

DATED at Vancouver, British Columbia this 30th day of November 2011.

PACIFIC NORTHERN GAS LTD.



R.G. Dyce
President & Chief Executive Officer

All notices and other communications in connection with this Application should be directed to:

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Pacific Northern Gas Ltd.
(PNG-West Division)

Summary of Proposed / Indicative Rates Effective January 1, 2012
(\$/GJ unless otherwise specified)

Customer Class	Rates Effective October 1, 2011	Proposed 2012 Revenue Requirement	Indicative 2011 / 12 Gas Supply Cost Change	Proposed Rates January 1, 2012	Rate Changes
Residential (RS 1)					
Monthly Fixed Charge	\$10.75			\$10.75	\$0.00
Natural Gas					
Delivery Charge	11.026	0.358		11.384	0.358
Company Use	0.126		(0.017)	0.109	(0.017)
GCVA Co. Use Rider	0.000		0.000	-	-
RSAM	0.156		(0.203)	(0.047)	(0.203)
Subtotal Delivery	11.308	0.358	(0.220)	11.446	0.138
Gas Supply Demand	0.392		0.060	0.452	0.060
Gas Supply Commodity	4.227		0.263	4.490	0.263
GCVA Commodity Rider	(0.199)		0.000	(0.199)	-
Subtotal Commodity	4.420		0.323	4.743	0.323
Total	15.728	0.358	0.103	16.189	0.461
Propane					
Delivery Charge	6.170	0.231		6.401	0.231
Gas Supply Charge	20.400		0.610	21.010	0.610
GCVA Rider	(0.308)		0.000	(0.308)	-
Total	26.262	0.231	0.610	27.103	0.841
Small Commercial Sales (RS 2)					
Monthly Fixed Charge	\$25.00			\$25.00	\$0.00
Delivery Charge	9.352	0.282		9.634	0.282
Company Use	0.126		(0.017)	0.109	(0.017)
GCVA Co. Use Rider	-		0.000	-	-
RSAM	0.156		(0.203)	(0.047)	(0.203)
Subtotal Delivery	9.634	0.282	(0.220)	9.696	0.062
Gas Supply Demand	0.384		0.058	0.442	0.058
Gas Supply Commodity	4.245		0.265	4.510	0.265
GCVA Commodity Rider	(0.199)		0.000	(0.199)	-
Subtotal Commodity	4.430		0.323	4.753	0.323
Total	14.064	0.282	0.103	14.449	0.385
Large Commercial Sales (RS 3)					
Monthly Fixed Charge	\$150.00			\$150.00	\$0.00
Delivery Charge	7.528	0.215		7.743	0.215
Company Use	0.126		(0.017)	0.109	(0.017)
GCVA Co. Use Rider	-		0.000	-	-
Subtotal Delivery	7.654	0.215	(0.017)	7.852	0.198
Gas Supply Demand	0.384		0.058	0.442	0.058
Gas Supply Commodity	4.245		0.265	4.510	0.265
GCVA Commodity Rider	(0.199)		0.000	(0.199)	-
Subtotal Commodity	4.430		0.323	4.753	0.323
Total	12.084	0.215	0.306	12.605	0.521
Commercial Transport (RS 22)					
Monthly Fixed Charge	\$25.00			\$25.00	\$0.00
Delivery Charge	9.352	0.282		9.634	0.282
Company Use	0.126		(0.017)	0.109	(0.017)
GCVA Co. Use Rider	-		0.000	-	-
RSAM	0.156		(0.203)	(0.047)	(0.203)
Total	9.634	0.282	(0.220)	9.696	0.062
Commercial Transport (RS 33)					
Monthly Fixed Charge	\$150.00			\$150.00	\$0.00
Delivery Charge	7.528	0.215		7.743	0.215
Company Use	0.126		(0.017)	0.109	(0.017)
GCVA Co. Use Rider	-		0.000	-	-
Total	7.654	0.215	(0.017)	7.852	0.198

Pacific Northern Gas Ltd.
(PNG-West Division)

Summary of Proposed / Indicative Rates Effective January 1, 2012
(\$/GJ unless otherwise specified)

Customer Class	Rates Effective October 1, 2011	Proposed 2012 Revenue Requirement	Indicative 2011 / 12 Gas Supply Cost Change	Proposed Rates January 1, 2012	Rate Changes
Commercial Interruptible Sales (RS 4)					
Monthly Fixed Charge	\$125.00			\$125.00	\$0.00
Delivery Charge	4.582	0.134		4.716	0.134
Company Use	0.126		(0.017)	0.109	(0.017)
GCVA Co. Use Rider	-		0.000	-	-
Subtotal Delivery	4.708	0.134	(0.017)	4.825	0.117
Gas Supply Demand	-		-	-	-
Gas Supply Commodity	4.236		0.282	4.518	0.282
GCVA Commodity Rider	(0.199)		0.000	(0.199)	-
Subtotal Commodity	4.037		0.282	4.319	0.282
Total	8.745	0.134	0.265	9.144	0.399
Small Industrial Sales (RS 5)					
Monthly Fixed Charge	\$410.00			\$410.00	\$0.00
Delivery Charge	3.337	0.096		3.433	0.096
Company Use	0.126		(0.017)	0.109	(0.017)
GCVA Co. Use Rider	-		0.000	-	-
Subtotal Delivery	3.463	0.096	(0.017)	3.542	0.079
Gas Supply Demand	0.175		0.024	0.199	0.024
Gas Supply Commodity	4.237		0.257	4.494	0.257
GCVA Commodity Rider	(0.199)		0.000	(0.199)	-
Subtotal Commodity	4.213		0.281	4.494	0.281
Total	7.676	0.096	0.264	8.036	0.360
Seasonal Off-Peak (RS 6)					
Off Peak (Mar - Nov)					
Monthly Fixed Charge	\$125.00			\$125.00	\$0.00
Delivery Charge	6.242	0.187		6.429	0.187
Company Use	0.126		(0.017)	0.109	(0.017)
GCVA Co. Use Rider	-		-	-	-
Subtotal Delivery	6.368	0.187	(0.017)	6.538	0.170
Gas Supply Demand	0.107		0.024	0.131	0.024
Gas Supply Commodity	4.234		0.137	4.371	0.137
GCVA Commodity Rider	(0.199)		0.000	(0.199)	-
Subtotal Commodity	4.142		0.161	4.303	0.161
Total	10.510	0.187	0.144	10.841	0.331
Peak (Dec - Feb)					
Monthly Fixed Charge	\$0.00			\$0.00	\$0.00
Delivery Charge	14.194	0.187		14.381	0.187
Company Use	0.126		(0.017)	0.109	(0.017)
GCVA Co. Use Rider	-		0.000	-	-
Subtotal Delivery	14.320	0.187	(0.017)	14.490	0.170
Gas Supply Demand	0.107		0.024	0.131	0.024
Gas Supply Commodity	4.234		0.137	4.371	0.137
GCVA Commodity Rider	(0.199)		0.000	(0.199)	-
Subtotal Commodity	4.142		0.161	4.303	0.161
Total	18.462	0.187	0.144	18.793	0.331

Pacific Northern Gas Ltd.
 (PNG-West Division)

Summary of Proposed / Indicative Rates Effective January 1, 2012
 (\$/GJ unless otherwise specified)

Customer Class	Rates Effective October 1, 2011	Proposed 2012 Revenue Requirement	Indicative 2011 / 12 Gas Supply Cost Change	Proposed Rates January 1, 2012	Rate Changes
NGV (RS 7)					
Monthly Fixed Charge	\$10.75			\$10.75	\$0.00
Delivery Charge	3.264	0.094		3.358	0.094
Company Use	0.126		(0.017)	0.109	(0.017)
GCVA Co. Use Rider	-		0.000	-	-
Subtotal Delivery	3.390	0.094	(0.017)	3.467	0.077
Gas Supply Demand	0.108		0.015	0.123	0.015
Gas Supply Commodity	4.214		0.213	4.427	0.213
GCVA Commodity Rider	(0.199)		0.000	(0.199)	-
Subtotal Commodity	4.123		0.228	4.351	0.228
Total	7.513	0.094	0.211	7.818	0.305

Pacific Northern Gas Ltd.
(PNG-West Division)

Summary of Proposed / Indicative Rates Effective January 1, 2012
(\$/GJ unless otherwise specified)

Customer Class	Rates Effective October 1, 2011	Proposed 2012 Revenue Requirement	Indicative 2011 / 12 Gas Supply Cost Change	Proposed Rates January 1, 2012	Rate Changes
Thompson Creek Mine- Supp No. 2					
Firm	3.1382	0.0965		3.2347	0.0965
Company Use	0.1260		(0.0170)	0.1090	(0.0170)
GCVA Co. Use Rider	0.0000		0.0000	0.0000	0.0000
	3.2642	0.0965	(0.0170)	3.3437	0.0795
Rio Tinto Alcan- Supp No. 7, 7A					
Firm	2.7125	0.0774		2.7899	0.0774
Company Use	0.1260		(0.0170)	0.1090	(0.0170)
GCVA Co. Use Rider	0.0000		0.0000	0.0000	0.0000
	2.8385	0.0774	(0.0170)	2.8989	0.0604
B.C. Hvdro- Supp No. 10					
Monthly Demand Charge	Firm	\$4,249.35	\$116.62	\$4,365.97	116.62
Interruptible Sales/Service	Int.	2.9868	0.0850	3.0718	0.0850
	Company Use	0.1260		(0.0170)	0.1090
	GCVA Co. Use Rider	0.0000		0.0000	(0.0170)
		3.1128	0.0850	(0.0170)	3.1808
Interruptible Sales/Service					
All Industrial T-Service Customers except West Fraser-Kitimat	Int.	2.9868	0.0850	3.0718	0.0850
	Company Use	0.1260		(0.0170)	0.1090
	GCVA Co. Use Rider	0.0000		0.0000	(0.0170)
		3.1128	0.0850	(0.0170)	3.1808

Pacific Northern Gas Ltd.
 (PNG-West Division)
 Bill Comparison
 October 2011 to January 2012

Customer Classification	Annual Use	Permanent Rates Oct. 1, 2011 \$/ GJ	Annual Bill Estimate \$	Proposed Rates Jan. 1, 2012 \$/ GJ	Annual Bill Estimate		Annual Bill Difference	
					\$	\$	\$	%
Residential:	68.0 GJ							
Monthly Fixed Charge @ 10.75 / mo.		1.897	129.00	1.897	129.00	n.a		
Delivery Charge		11.152	758.34	11.493	781.50	23.17		
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	-		
RSAM Rider		0.156	10.61	(0.047)	(3.20)	(13.80)		
			897.94		907.31	9.36	1.0%	
Gas Supply Charge		4.619	314.09	4.619	314.09	-		
GCVA Rider		(0.199)	(13.53)	(0.199)	(13.53)	-		
			300.56		300.56	-	0.0%	
Carbon Tax		1.2415	84.42	1.2415	84.42	-		
		\$18.867 /GJ	\$1,282.93	\$19.004 /GJ	\$1,292.29	\$9.36	0.7%	

Small Commercial:	319.7 GJ							
Monthly Fixed Charge @ 25.00 / mo.		0.938	300.00	0.938	300.00	n.a		
Delivery Charge		9.478	3,030.12	9.743	3,114.90	84.78		
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	-		
RSAM Rider		0.156	49.87	(0.047)	(15.03)	(64.90)		
			3,379.99		3,399.88	19.89	0.6%	
Gas Supply Charge		4.629	1,479.89	4.629	1,479.89	-		
GCVA Rider		(0.199)	(63.62)	(0.199)	(63.62)	-		
			1,416.27		1,416.27	-	0.0%	
Carbon Tax		1.2415	396.91	1.2415	396.91	-		
		\$16.244 /GJ	\$5,193.17	\$16.306 /GJ	\$5,213.05	\$19.89	0.4%	

Granisle Propane

Residential:	57.6 GJ							
Monthly Fixed Charge @ 10.75 / mo.		2.240	129.00	2.240	129.00	n.a		
Delivery Charge		6.170	355.39	6.401	368.69	13.30		
			484.39		497.69	13.30	2.7%	
Gas Supply Charge		20.400	1,175.04	20.400	1,175.04	0		
GCVA Rider		(0.308)	(18)	(0.308)	(17.74)	0		
			1,157.30		1,157.30	0	0.0%	
Carbon Tax		1.5043		1.504				
		\$30.006 /GJ	\$1,641.69	\$30.237 /GJ	\$1,654.99	\$13.30	0.8%	

Pacific Northern Gas Ltd.
(PNG-West Division)

**SUMMARY OF PROPOSED GAS DELIVERY CHARGE RATE CHANGES
EFFECTIVE JANUARY 1, 2012**

Customer Classification	2012 Test Year Physical Deliveries (GJ)	2012 Test Year Marginable Deliveries (GJ)	2012 Gross Margin (\$)	2012 Normalized Gross Margin (\$)	Allocation of Revenue Deficiency (\$)	Proposed Rate Changes for Rev. Def. (\$/GJ)
Residential (Rate 1)	1,206,046	1,206,046	15,717,230	15,717,230	431,359	0.358
Granisle (Rate 1 - Propane)	8,869	8,869	74,587	74,587	2,047	0.231
Commercial						
Small Commercial Firm (Rate 2)	802,471	802,471	8,345,156	8,345,156	229,032	0.282
Large Commercial Firm (Rate 3)	40,497	40,497	320,075	320,075	8,784	0.215
Small Comm Transport (Rate 22)	150,747	150,747	1,456,218	1,456,218	39,966	0.282
Large Comm Transport (Rate 33)	151,095	151,095	1,179,113	1,179,113	32,361	0.215
Large Commercial Interr (Rate 4)	24,500	24,500	119,429	119,429	3,278	0.134
Total Commercial	1,169,310	1,169,310	11,419,990	11,419,990		
Seasonal Off-Peak (Rate 6)	16,800	16,800	114,602	114,602	3,145	0.187
NGV (Rate 7)	11,050	11,050	37,788	37,788	1,037	0.094
Small Industrial						
Sales (Rate 5)	183,800	183,800	677,656	677,656	18,598	0.096
Transport	117,237	117,237	380,691	380,692	10,448	0.0965
Interruptible Transport	500,723	500,723	1,550,138	1,550,138	42,543	0.0850
Total Small Industrial	801,760	801,760	2 608 485	2 608 486		
Large Industrial						
Rio Tinto Alcan						
Firm Transport	431,148	431,148	1,216,481	1,216,481	33,386	0.0774
Interruptible Transport	309,852	309,852	959,238	959,238	26,326	0.0850
Sub-total	741,000	741,000	2,175,719	2,175,719		
B.C. Hydro - Interruptible Transport	24,000	24,000	125,290	125,290	3,439	0.1433
Total Large Industrial	765,000	765,000	2,301,009	2,301,009		
TOTAL	3,978,835	3,978,835	32,273,691	32,273,693	885,750	

Note: Each customer class share of the revenue deficiency is allocated based on the proportion of each customer class normalized gross margin to total normalized gross margin times the revenue deficiency. The allocated revenue deficiency divided by forecast deliveries equals the proposed rate change.

Pacific Northern Gas Ltd.
(PNG-West Division)

SUMMARY OF GROSS REVENUE, COST OF GAS, GROSS MARGIN

Customer Classification	2012 Test Year Physical Gas Deliveries (GJ)	2012 Test Year Marginable Gas Deliveries (GJ)	Adjusted Revenue (\$)	Cost of Gas (\$)	Gross Margin (\$)
Residential (Rate 1)	1,206,046	1,206,046	21,677,510	5,960,279	15,717,230
Granisle	8,869	8,869	260,925	186,338	74,587
Commercial					
Small Commercial Firm (Rate 2)	802,471	802,471	12,318,992	3,973,836	8,345,156
Large Commercial Firm (Rate 3)	40,497	40,497	520,616	200,541	320,075
Commercial Transport (Rate 22)	150,747	150,747	1,456,218	0	1,456,218
Commercial Transport (Rate 33)	151,095	151,095	1,179,113	0	1,179,113
Large Commercial Interr (Rate 4)	24,500	24,500	230,120	110,691	119,429
Total Commercial	1,169,310	1,169,310	15,705,058	4,285,069	11,419,990
Seasonal off-peak (Rate 6)	16,800	16,800	190,236	75,634	114,602
NGV (Rate 7)	11,050	11,050	88,065	50,278	37,788
Small Industrial					
Sales (Rate 5)	183,800	183,800	1,540,229	862,573	677,656
Transport	117,237	117,237	380,691	0	380,691
Deficiency Incurred	0	0	0	0	0
Deficiency Make-Up	0	0	0	0	0
Interruptible Transport	500,723	500,723	1,550,138	0	1,550,138
Total Small Industrial	801,760	801,760	3,471,058	862,573	2,608,485
Large Industrial					
Rio Tinto Alcan					
Firm Transport	431,148	431,148	1,216,481	0	1,216,481
Interruptible Transport	309,852	309,852	959,238	0	959,238
Sub-total	741,000	741,000	2,175,719	0	2,175,719
B.C. Hydro - Interruptible Transport	24,000	24,000	125,290	0	125,290
Total Large Industrial	765,000	765,000	2,301,009	0	2,301,009
TOTAL	3,978,835	3,978,835	43,693,862	11,420,170	32,273,691

Pacific Northern Gas Ltd.
(PNG-West Division)

Derivation of Test Year Forecast Gross Margin

Customer Classification		2012 Test Year Deliveries (GJ)	Current Delivery Charge (\$ / GJ)	Delivery Margin (\$)	Weighted Avg. Customer Count	Current Fixed Charge	Fixed Charge Margin	Total Delivery & Fixed Charge Margin	
Sales:									
Residential (Rate 1)		1,206,046	11.135	13,429,322	17,736	10.75	2,287,912	15,717,234	
Granisle (Rate 1 - Propane)		8,869	6.170	54,722	154	10.75	19,866	74,588	
Commercial									
Small Commercial (Rate 2)		802,471	9.461	7,592,178	2,510	25.00	753,000	8,345,178	
Large Commercial Firm (Rate 3)		40,497	7.637	309,276	6	150.00	10,800	320,076	
Large Commercial Interr (Rate 4)		24,500	4.691	114,930	3	125.00	4,500	119,430	
Total Commercial		867,468		8,016,383	2,519		768,300	8,784,683	
Seasonal Off-Peak (Rate 6)	Off-Peak	16,513	6.351	104,874	5	125.00	5,625	110,499	
	Peak	287	14.303	4,105				4,105	
		16,800		108,979	5		5,625	114,604	
NGV (Rate 7)		11,050	3.373	37,272	4	10.75	516	37,788	
Small Industrial Sales (Rate 5)		183,800	3.446	633,375	9	410.00	44,280	677,655	
Subtotal Sales		2,294,033		22,280,053			3,126,499	25,406,551	
Transportation:									
	Forecast Deliveries	Non-Delivered GJ's/ Deficiency Volumes (Make Up) Incurred	2012 Test Year Marginable Deliveries (GJ)	Current Delivery Charge (\$ / GJ)	Delivery Margin (\$)	Weighted Avg. Customer Count	Current Fixed Charge	Fixed Charge Margin	Total Delivery & Fixed Charge Margin
Commercial									
Small Comm Transport (Rate 22)	150,747		150,747	9.461	1,426,217	100	25.00	30,000	1,456,217
Large Comm Transport (Rate 33)	151,095		151,095	7.637	1,153,913	14	150.00	25,200	1,179,113
Total Commercial	301,842	0	301,842		2,580,130	114		55,200	2,635,330
Small Industrial									
Firm Transportation	117,237	0	117,237	3.2472	380,692	1		0	380,692
Total Small Industrial Firm	117,237	0	117,237		380,692		0	0	380,692
Deficiency At Company Use Rate				0.1090	0				0
Interruptible Transportation	500,723	0	500,723	3.0958	1,550,138	8			1,550,138
Total Small Industrial	617,960	0	617,960		1,930,830			0	1,930,830
Rio Tinto Alcan									
Firm Transportation	431,148	0	431,148	2.8215	1,216,484	1		0	1,216,484
Interruptible	309,852	0	309,852	3.0958	959,240				959,240
Sub-total	741,000	0	741,000		2,175,724		0	0	2,175,724
B.C. Hydro - Interruptible	24,000	0	24,000	3.0958	74,299	1	4249.35	50,992	125,291
Subtotal Transportation	1,684,802	0	1,684,802		6,760,983			106,192	6,867,175
TOTAL			3,978,835		29,041,036			3,232,691	32,273,727

Pacific Northern Gas Ltd.
(PNG-West Division)

Derivation of Indicative Test Year Forecast Gas Supply Cost

Customer Classification	2012 Test Year Deliveries (GJ)	Indicative Gas Cost Charge (\$ / GJ)	Indicative Gas Cost (\$)
Residential (Rate 1)	1,206,046	4.942	5,960,279
Granisle (Propane)	8,869	21.010	186,338
Commercial			
Small Commercial (Rate 2)	802,471	4.952	3,973,836
Large Commercial Firm (Rate 3)	40,497	4.952	200,541
Large Commercial Interr (Rate 4)	24,500	4.518	110,691
Total Commercial	867,468		4,285,069
Seasonal Off-Peak (Rate 6)	16,800	4.502	75,634
NGV (Rate 7)	11,050	4.550	50,278
Small Industrial			
Sales (Rate 5)	183,800	4.693	862,573
Total	2,294,033		11,420,170

**Pacific Northern Gas Ltd.
(PNG-West Division)**

DERIVATION OF INDICATIVE GAS SUPPLY COST RATE CHANGES EFFECTIVE JANUARY 1, 2012

Using 5 Day Average Ending November 25, 2011 Forward Gas Strip

Customer Classification	Gas Supply Costs Rates Effective October 1, 2011				Gas Supply Costs Indicative Rates Effective January 1, 2012				Indicative Gas Supply Cost Rate Changes Effective January 1, 2012			
	Demand ⁽¹⁾	Commodity ⁽²⁾	Total D&C	Company Use Gas ⁽³⁾	Demand ⁽¹⁾	Commodity ⁽²⁾	Total D&C	Company Use Gas ⁽³⁾	Demand ⁽¹⁾	Commodity ⁽²⁾	Total D&C	Company Use Gas
Residential (RS1)	0.392	4.227	4.619	0.126	0.452	4.490	4.942	0.109	0.060	0.263	0.323	(0.017)
Commercial Firm (RS2 and RS3)	0.384	4.245	4.629	0.126	0.442	4.510	4.952	0.109	0.058	0.265	0.323	(0.017)
Commercial Interruptible (RS4)	0.000	4.236	4.236	0.126	0.000	4.518	4.518	0.109	0.000	0.282	0.282	(0.017)
Small Industrial (RS5)	0.175	4.237	4.412	0.126	0.199	4.494	4.693	0.109	0.024	0.257	0.281	(0.017)
Seasonal Off Peak (RS6)	0.107	4.234	4.341	0.126	0.131	4.371	4.502	0.109	0.024	0.137	0.161	(0.017)
NGV (RS7)	0.108	4.214	4.322	0.126	0.123	4.427	4.550	0.109	0.015	0.213	0.228	(0.017)
Transportation Service				0.126				0.109				(0.017)

- Notes: 1. The demand charges represent the projected fixed costs payable by PNG regardless of the quantity of gas purchased. PNG's demand charges relate to the firm service it holds on the Spectra Energy Pipeline system and fixed fees payable to its energy management service provider. Only those customers receiving gas on a firm basis pay demand charges to PNG as part of their gas supply charge.
2. The commodity charges are payable for each GJ of gas purchased by PNG. The commodity charges represent PNG's projection of its commodity costs based on its projected gas supply purchases.
3. The unit company use gas cost rate is determined by dividing the total projected cost of company use gas by projected gas sales to all customer classes except West Fraser-Kitimat as they supply their share of Company use gas in kind.

**Pacific Northern Gas Ltd.
(PNG-West Division)**

**Allocation of Indicative 2012 Demand Charges
to Firm Customer Classifications and Company Use Gas**

Customer Classification	2012 Peak Day Requirement ⁽¹⁾		Allocation of Demand Charges (\$)	2012 Annual Gas Requirements (GJ)	Unit Demand Charge ⁽²⁾ (\$/GJ)
	(GJ)	(%)			
Residential (RS1)	12 501	56.32	545,710	1 206 046	0.452
Commercial (RS2 and RS3)	8 534	38.45	372,559	842 968	0.442
Small Industrial (RS5)	839	3.78	36,626	183 800	0.199
Seasonal Off Peak (RS6)	0	0.00	2,201	16 800	0.131
NGV (RS7)	30	0.14	1,357	11 050	0.123
Company Use	292	1.32	12,790		-----
Total	22 196	100.0	971,243		
	Demand Charges net of portion allocated to seasonal off-peak (RS6) customers.		\$968,945		

Notes: 1. PNG allocates its demand charges to each customer classification based on the proportion their projected peak day gas requirement bears to the total projected peak day gas requirement, except for the seasonal off peak customers. The seasonal off peak (RS6) customers receive firm gas supply during the off peak period (i.e. March 1 to November 30) and therefore they should bear some of the demand charges. Their share of the demand charges is based on applying the unit demand charge assuming a 150 percent load factor to the seasonal off peak customers' projected deliveries.

2. The unit demand charge is the allocated demand charge divided by the projected annual gas requirements for each customer classification. There is no unit demand charge for Company use gas as the demand charges and the commodity charges for company use gas are totalled and then spread over total sales (i.e. the sum of sales and transportation service.)

Pacific Northern Gas Ltd.
(PNG-West Division)

Determination of Indicative 2012 Unit Company Use Gas Cost Rate

Using 5 Day Average Ending November 25, 2011 Forward Gas Strip	
Demand Cost	\$12,790
Commodity Charge	\$308,408
Motor Fuel Tax	\$22,104
Carbon Tax	\$89,848
Total Company Use Gas Cost	<u>\$433,150</u>
Total Company use gas requirement	<u>68 332 GJ</u>
Total GJ attracting margin, excl'd Granisle propane system	<u>3 969 966 GJ</u>
2012 Unit Company Use Gas Cost Rate	
\$0.109 /GJ	<u>433 150</u>
	3 969 966
Commodity Cost of Company Use Gas per GJ Purchased	
\$4.513 /GJ	<u>308 408</u>
	68 332

**Pacific Northern Gas Ltd.
(PNG-West Division)**

Determination of Indicative 2012 Revenue Stabilization Adjustment Mechanism (RSAM) Rider

	Residential	Small Commercial	Total
RSAM balance at year-end 2010 after-tax	\$1,271,112	(\$550,890)	\$720,223
RSAM recovery/deferral in 2011 after-tax	(542,513)	(403,797)	(946,310)
RSAM balance at year-end 2011 after-tax	\$728,599	(\$954,687)	(\$226,088)
Years of amortization			3
RSAM balance divided by 3 equals 2012 after-tax amortization			(\$75,363)
2012 pre-tax amortization at 2012 tax rate			(\$100,483)
Forecast 2012 deliveries	1,206,046	953,218	2,159,264
One year of pre-tax amortization divided by 2012 deliveries equals RSAM rate rider (\$/GJ)			(0.047)

Pacific Northern Gas Ltd.
 (PNG-West Division)

Forward Gas Price Strip
 5 Day Average Ending November 25, 2011

	STATION #2 CDN\$/GJ	AECO CDN\$/GJ
Jan-12	3.0152	3.2332
Feb-12	2.9822	3.2402
Mar-12	2.9436	3.2376
Apr-12	2.9381	3.1971
May-12	2.9587	3.2177
Jun-12	2.9662	3.2252
Jul-12	2.9927	3.2517
Aug-12	3.0128	3.2738
Sep-12	3.0347	3.2957
Oct-12	3.0895	3.3485
Nov-12	3.3265	3.5705
Dec-12	3.6218	3.8058
Average	3.0735	3.3248

Pacific Northern Gas Ltd.
 (PNG-West Division)

Granisle 2012 Indicative Propane Cost Forecast

Conversion from Litres to GJ

25.53 MJ/L

2011 Forecast	Propane Requirement Litres	Forecast Propane Price (\$/L)	(\$)	Propane Requirement GJ	Supply Charge (\$/GJ)
January	63,455	0.5422	\$34,405	1 620	21.238
February	47,552	0.5542	\$26,353	1 214	21.708
March	37,995	0.5422	\$20,601	970	21.238
April	35,997	0.5412	\$19,482	919	21.199
May	19,311	0.5282	\$10,200	493	20.690
June	12,534	0.5182	\$6,495	320	20.297
July	7,364	0.5122	\$3,772	188	20.064
August	6,110	0.5162	\$3,154	156	20.218
September	14,297	0.5142	\$7,352	365	20.142
October	24,481	0.5182	\$12,686	625	20.298
November	34,391	0.5332	\$18,337	878	20.885
December	43,909	0.5352	\$23,500	1 121	20.963
Total	347,396	0.5364	\$186,337	8 869	21.010

**Pacific Northern Gas Ltd.
(PNG-West Division)**

UTILITY INCOME & RETURN

**SCHEDULE 1
(000's)**

Line No.		Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008	Source
1	Energy sales (TJ)	2 294	2 276	2 330	2 965	3 070	Tab Rates, page 8
2	Average rate per GJ	\$16.37	\$16.32	\$17.65	\$14.73	\$15.40	
3							
4	Transportation service (TJ)	1 685	1 678	1 868	3 213	3,572	Tab Rates, page 8
5	Average rate per GJ	4.17	3.96	3.79	1.72	\$1.73	
6							
7	Total deliveries (TJ)	3 979	3 954	4 197	6 178	6,642	Tab Rates, page 8
8							
9	Utility revenue						
10	Energy sales	\$36,827	\$36,731	\$41,125	\$43,658	\$47,294	Tab Rates, page 7
11	Interim rates - sales	724	405		0		Tab Rates, page 6
12	Transportation service	6,867	6,567	7,084	5,543	6,180	Tab Rates, page 7
13	Interim rates - transportation	162	82		0		Tab Rates, page 6
14							
15		44,580	43,784	48,209	49,201	53,474	
16	Cost of sales	11,420	11,859	12,958	19,979	25,251	Tab Rates, page 10
17							
18	Gross margin	33,159	31,925	35,251	29,222	28,223	
19							
20	Operating expenses	8,612	8,113	7,922	7,820	7,676	Tab 1, page 2, line 6
21	Maintenance expenses	647	492	484	346	344	Tab 1, page 2, line 10
22	Admin. & general expenses	8,523	7,937	7,096	6,714	5,968	Tab 1, page 2, line 16
23	Property taxes	3,696	3,637	3,560	3,527	3,672	Tab 1, page 6, line 4
24	Depreciation	5,105	5,337	6,795	6,678	6,522	Tab 2, page 6, line 45
25	Amortization on gross deferrals (net pre 2011)	(632)	(1,016)	714	722	825	Tab 2, page 13, line 20
26	CAP/ROE deferred revenue	0	0	(869)	(770)		Tab App., page 3
27	Investment income, other revenue & credits	(3,196)	(2,638)	(2,383)	(2,605)	(2,026)	Tab 1, page 7, line 11
28	West Fraser Termination Pmt. Amort. & Interest	(1,806)	(1,687)	(143)	(5,466)	(6,592)	Tab 2, page 14, line 29
29	PTP Settlement Allowance		(500)				
30	NSP Settlement Allowance		(200)	0	(110)	0	
31					0	0	
31		20,949	19,475	23,177	16,857	16,388	
32							
33	Earned return before income taxes	12,211	12,450	12,074	12,365	11,835	
34	Future Income taxes on Deferrals	189	291				Tab 2, page 13, line 21
35	Income taxes	748	835	1,600	1,826	1,510	Tab 3, page 1, line 14
36							
37	Earned return	\$11,273	\$11,324	\$10,474	\$10,539	\$10,325	
38							
39	Utility rate base	\$133,205	\$130,808	\$126,514	\$129,197	\$130,479	Tab 2, page 1, line 24
40							
41	Return on rate base	8.46%	8.66%	8.28%	8.16%	7.91%	Tab 5, page 1, line 23

Pacific Northern Gas Ltd.
 (PNG-West Division)

SUMMARY OF OPERATING, MAINTENANCE
 & ADMINISTRATIVE & GENERAL EXPENSES

(000's)

Line No.	Account and Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	OPERATING EXPENSES					
2	- wages	4,862	4,625	4,676	4,368	4,143
3	- gas	433	486	499	540	780
4	- transferred to capital	(399)	(675)	(532)	(573)	(628)
5	- other	3,717	3,678	3,279	3,441	3,380
6	Total Operating	8,612	8,113	7,922	7,776	7,676
7	MAINTENANCE EXPENSES					
8	- wages	244	207	218	166	171
9	- other	403	284	266	224	172
10	Total Maintenance	647	492	484	390	344
11	ADMINISTRATIVE AND GENERAL EXPENSES					
12	- wages	2,724	2,442	2,358	2,154	1,792
13	- benefits	3,317	2,820	2,179	2,039	2,178
14	- transferred to capital	(582)	(148)	(821)	(851)	(1,011)
15	- other	3,064	2,823	4,122	3,247	2,856
16	Total Admin & General	8,523	7,937	7,839	6,589	5,815
17	TOTAL EXPENSES	17,782	\$16,541	\$16,244	\$14,755	\$13,834

Pacific Northern Gas Ltd.
(PNG-West Division)

OPERATING EXPENSES

(000's)

Line No.	Account and Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	660 Supervision	108	102	91	95	97
2	664 Communications	121	119	141	139	131
3	665 Pipelines	758	818	645	615	594
4	Pipelines - West Fraser Fuel Gas	0	0	0	(242)	(328)
4	Pipelines - Gas	5	5	13		-
5	Pipelines - Spectra Gas Control	259	254	253	260	224
6	666 Compressors	411	401	393	372	406
7	Compressors - Gas	300	300	353	558	867
8	667 Regulating stations	242	199	290	292	312
9	Regulating stations - Gas	100	157	127	216	233
10	Total transmission	2,305	2,356	2,307	2,305	2,537
11	670 Supervision	511	454	436	405	442
12	671 Load dispatching	0	0	0	0	0
13	673 Removing & resetting meters	365	370	314	312	305
14	674 Service on customer premises	41	41	43	46	41
15	675 Mains and services	380	374	365	332	315
16	677 Regulating stations	7	7	9	3	3
17	679 Other	0	0	0	0	0
18	Total distribution	1,304	1,247	1,166	1,098	1,106
19	684 Communications	9	9	19	8	10
20	685 General systems operations	2,074	2,036	1,843	1,765	1,798
	- Office Heating gas	27	24	6	8	8
21	688 Other general operations	1,404	1,356	1,318	1,405	1,100
21	689 Transferred to capital	(399)	(675)	(532)	(573)	(628)
22	Total general	3,115	2,749	2,652	2,613	2,288
23	700 Sales supervision	6	9	1	4	5
24	701 Advertising	37	40	47	36	26
25	702 Demonstration and selling	3	7	1	2	1
26	709 Other	0	0	0	1	0
27	Total sales	47	55	49	43	32
28	711 Customer contracts	402	370	370	350	343
29	712 Meter reading	319	294	306	309	317
30	713 Customer billing	914	925	838	848	764
31	714 Credit and collections	105	118	86	100	138
32	718 Uncollectible accounts	100	0	147	153	150
33	Total customer accounting	1,841	1,706	1,747	1,760	1,713
34	Total operating	8,612	8,113	7,922	7,819	\$7,676
	Excl co use gas	\$8,179	\$7,627	\$7,423	\$7,279	\$6,896

Pacific Northern Gas Ltd.
(PNG-West Division)

MAINTENANCE EXPENSES

(000's)

Line No.	Account and Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	864 Communications	10	9	5	2	18
2	865 Pipe lines	85	57	57	20	46
3	866 Compressors	28	29	17	4	18
4	867 Regulating stations	92	85	51	78	65
5	Total transmission	215	179	130	104	148
6	872 Structures	2	2	1	1	0
7	875 Mains and services	145	124	164	122	121
8	877 Regulating stations	3	3	1	1	1
9	878 Meters	230	157	157	94	55
10	879 Other	0	0	0	0	0
11	Total distribution	380	285	322	218	176
12	884 Communications	10	4	6	1	2
13	885 General	41	23	26	24	18
14	Total general	52	27	32	25	20
15	Total maintenance	\$647	\$492	\$484	\$347	\$344

Pacific Northern Gas Ltd.
(PNG-West Division)

ADMINISTRATIVE AND GENERAL EXPENSES

(000's)

Line No.	Account and Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	721 Administration	3,698	3,422	3,270	3,274	2,834
2	Total administration	3,698	3,422	3,270	3,274	2,834
3	722 Audit fees	243	244	233	258	128
4	Legal fees	130	93	92	72	90
5	Consulting fees	267	188	216	315	241
6	Total special services	639	525	541	645	458
7	723 Insurance	736	737	806	833	846
8	725 Canada Pension Plan	215	218	194	197	182
9	Life and disability insurance	278	270	470	432	421
10	Unemployment Insurance	95	90	84	86	80
11	Employee Savings Plan	322	280	264	249	248
12	Company pension plans	1,662	1,214	828	769	896
13	Medical and hospital insurance	85	80	108	103	104
14	Workers Compensation Board	55	61	68	49	56
15	Other programs	605	640	163	154	191
16	Total employee benefits	3,317	2,853	2,179	2,039	2,178
17	728 Fiscal and corporate expense	203	219	269	171	226
18	Directors fees and expenses	275	278	632	386	230
19	Regulation	37	55	51	46	17
20	Donations	25	32	17	17	15
21	Corporate memberships	56	57	51	51	55
22	Other	9	15	5	11	0
23	Stock option benefit expense	109	109	96	92	121
24	Total general expense	715	764	1,121	774	662
25	729 Transferred to capital	(582)	(148)	(821)	(851)	(1,011)
26	75x Non-regulated business	0	482	743		
	Subtotal general and administrative	8,523	8,635	7,839	6,714	5,968
27	Cost adjustments					
28	50% of donations	0	(16)	(9)	(9)	(7)
29	Stock option benefit expense	0	(109)	(96)	(92)	(121)
30	Pension expense on bonuses and incentives	0	(33)	(27)	(25)	(25)
31	Non-regulated business & benefit allocations	0	(541)	(743)	0	0
33	Subtotal cost adjustments	0	(698)	(874)	(125)	(153)
34	Total general and administrative	\$8,523	\$7,937	\$6,965	\$6,589	\$5,815

Pacific Northern Gas Ltd.
 (PNG-West Division)

TAXES OTHER THAN INCOME TAXES

(000's)

Line No.	Account and Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	PROPERTY TAXES					
2	Regular	\$3,287	\$3,188	\$3,092	\$3,079	\$2,989
3	1% in lieu	409	449	468	448	521
4	TOTAL	\$3,696	\$3,637	\$3,560	\$3,527	\$3,510

Pacific Northern Gas Ltd.
 (PNG-West Division)

MISCELLANEOUS OPERATING REVENUES & CREDITS

(000's)

Line No.	Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	Penalty charges	\$94	\$94	\$92	\$102	\$96
2	Connection Fees	96	105	92	104	106
3	Rents	6	6	6	3	0
4	Overheads recovered	42	62	153	52	13
5	Automotive surcharges	(0)	(0)	0	0	(0)
6	Commission - PST Tax	0	0	2	1	1
7	Shared Services - Tumbler Ridge	156	149	130	126	123
8	Shared Services - FSJ / DC	2,289	2,189	1,907	1,831	1,685
9	Utility charges to NRB	511	31	0		
10	Other	2	2	2	386	2
11		<u>\$3,196</u>	<u>\$2,638</u>	<u>\$2,383</u>	<u>\$2,605</u>	<u>\$2,026</u>

**Pacific Northern Gas Ltd.
(PNG-West Division)**

UTILITY RATE BASE

**SCHEDULE 2
(000'S)**

Line No.		Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008	Source
1	Plant in service beginning of year	\$269,998	\$263,200	\$263,200	\$253,515	\$247,369	Tab 2, page 3, line 46
2	Additions	\$4,146	\$4,001	\$4,401	5,259	\$6,726	Tab 2, page 3, line 46
3	Disposals (at cost)	(203)	(79)	(437)	(685)	(579)	Tab 2, page 3, line 46
4							
5	Plant in service end of year	273,941	\$267,122	267,164	258,089	253,515	
6	Accumulated depreciation	135,222	129,412	129,001	116,080	109,875	Tab 2, page 6, line 39
7							
8	Net plant in service end of year	138,720	\$137,710	138,163	142,009	143,641	
9							
10	Net plant beginning of year	139,943	139,444	139,444	143,641	143,941	Tab 2, pg 4 & 7, lines 1 & 1
11							
12	Net plant in service midyear	139,331	138,577	138,804	142,825	143,791	
13	Adjustment - expenditure/disposal timing	(6)	106	(6)	(308)	346	
14	Contributions in aid of construction	(4,779)	(4,776)	(4,881)	(5,081)	(5,272)	Tab 2, page 8, line 17
15	Pension funding in excess of expense	1,971	0	0	0	0	Tab 2, page 10, line 32
16	Non-pension post retirement credit	(2,158)	0	0			Tab 2, page 11, line 38
17	Deferred income taxes	(7,345)	(10,362)	(11,312)	(12,212)	(13,112)	Tab 2, page 12, line 8
18	Work in progress, no AFUDC	100	100	100	100	100	Tab 2, page 9, line 5
19	Unamortized deferred charges	2,671	3,031	1,747	1,425	1,588	Tab 2, page 13, line 9
20	Cash working capital	1,782	2,311	356	496	1,010	Tab 2, page 15, line 9
21	Other working capital	1,637	1,822	1,706	1,952	2,028	Tab 2, page 20, line 15
22							
23	Utility rate base, midyear	<u>\$133,205</u>	<u>\$130,808</u>	<u>\$126,514</u>	<u>\$129,197</u>	<u>\$130,479</u>	

Pacific Northern Gas Ltd.
 (PNG-West Division)
 GAS PLANT IN SERVICE
 2011
 (\$ 000's)

Line	Description	Forecast					Forecast '11 Ending Balance
		Actual Jan/11 Beginning Balance	Additions	Overheads	Transfers	Retirements	
1	Processing plant						
2	443 Gas Holders - Storage	30					30
3	449 Other local storage equip.	3					3
4							
5		33					33
6	Transmission plant						
7	460 Land	100					100
8	461 Land rights	1,202					1,202
9	462 Compressor structures	2,546					2,546
10	463 Regulating structures	1,321					1,321
11	465 Mains	144,940	2,338	889		(325)	147,843
12	466 Compressor equipment	21,934	20	9			21,962
13	467 Regulating equipment	7,675	47	21			7,743
14	468 Communications	2,971					2,971
15	469 Other	2					2
16		182,691	2,405	920		(325)	185,691
17	Distribution plant						
18	470 Land	1					1
19	471 Land rights	34					34
20	472 Structures	226					226
21	473 Services	24,697	154	71			24,922
22	474 House installations	3,944	21	10			3,975
23	475 Mains	29,861	100	46			30,007
24	477 Regulating equipment	287					287
25	478 Meters	4,404	100				4,504
26	479 Other	31					31
27		63,485	376	127			63,988
28	General plant						
29	480 Land	295					295
30	481 Land rights						
31	482 Structures	5,834	92			(25)	5,900
32	483 Office equipment	827	38				865
33	484 Transportation equipment	2,148	158			(79)	2,226
34	485 Heavy work equipment	3,005					3,005
35	486 Tools	2,658	135			(8)	2,784
36	487 Computer equipment	1,538	146				1,684
37	488 Communications	685	6				690
38	489 Other	2					2
39		16,991	574			(112)	17,452
40	Construction overheads						
41	Unallocated construction costs						
42	System operations transfers						
43	Administrative transfers						
44	Depreciation						
45							
46		263,200	3,354	1,046		(437)	267,164

Pacific Northern Gas Ltd.
(PNG-West Division)
GAS PLANT IN SERVICE
2012
(\$ 000's)

Line	Description	Forecast				Forecast '12 Ending Balance
		Jan/12 Forecast Beginning Balance	Forecast Additions	O/H Allocations	Forecast Retirements	
1	Processing plant					
2	443 Gas Holders - Storage	30				30
3	449 Other local storage equip.	3				3
4						
5		33				33
6	Transmission plant					
7	460 Land	104				104
8	461 Land rights	1,232				1,232
9	462 Compressor structures	2,788				2,788
10	463 Regulating structures	1,358				1,358
11	465 Mains	148,568	1,152	686		150,407
12	466 Compressor equipment	23,652	171	102		23,926
13	467 Regulating equipment	7,848	23	14		7,884
14	468 Communications	2,972	2	1		2,975
15	469 Other	2				2
16		188,525	1,348	803		190,676
17	Distribution plant					
18	470 Land	1				1
19	471 Land rights	34				34
20	472 Structures	226	20	12		258
21	473 Services	24,922	149	89		25,160
22	474 House installations	3,975	28	17		4,019
23	475 Mains	30,007	198	118		30,323
24	477 Regulating equipment	287				287
25	478 Meters	4,504	245			4,750
26	479 Other	31				31
27		63,988	640	235		64,863
28						
29	480 Land	295				295
30	481 Land rights					
31	482 Structures	5,900	49			5,949
32	483 Office equipment	865	10			875
33	484 Transportation equipment	2,226	405		(203)	2,429
34	485 Heavy work equipment	3,005	206			3,211
35	486 Tools	2,784	166			2,950
36	487 Computer equipment	1,684	285			1,968
37	488 Communications	690				690
38	489 Other	2				2
39		17,452	1,120		(203)	18,370
40						
41	Unallocated construction costs					
42	System operations transfers		399	(399)		
43	Administrative transfers		582	(582)		
44	Depreciation		57	(57)		
45			1,038	(1,038)		
46		269,998	4,146		(203)	273,941

Pacific Northern Gas Ltd.
 (PNG-West Division)

GAS PLANT IN SERVICE - CONTINUITY OF PLANT COST

(000's)

<u>Line</u>	<u>Description</u>	<u>Test Yr 2012</u>	<u>Forecast 2011</u>
1	Balance, Beginning of Year	269,998	263,200
2	CIAC Balance, Beginning of Year	<u>(9,201)</u>	<u>(8,993)</u>
3	Plant Cost, net of CIAC, Beginning of Year	<u>260,797</u>	<u>254,208</u>
4	Additions during year:		
5	Plant Cost	3,107	3,354
6	Allocation of overheads	1,038	1,046
7	Total Plant Additions	<u>4,146</u>	<u>4,401</u>
8	Contributions in Aid of Construction	<u>(15)</u>	<u>(208)</u>
9	Total Additions	<u>4,131</u>	<u>4,193</u>
10	Plant Retirements:		
11	Normal Course	(203)	(437)
12	Extraordinary Plant Loss		
13	CIAC Retirements		
14	Total Retirements	<u>(203)</u>	<u>(437)</u>
15	Balance, End of Year	<u>264,725</u>	<u>257,963</u>
16	Closing balance consists of:		
17	Plant Cost	273,941	267,164
18	CIAC	<u>(9,216)</u>	<u>(9,201)</u>
19	Balance, End of Year	<u>264,725</u>	<u>257,963</u>

Pacific Northern Gas Ltd.
(PNG-West Division)
CONTINUITY OF
ACCUMULATED DEPRECIATION
2012

Line	Description	Rate	Forecast			Forecast '12 Ending Balance
			Jan/12 Forecast Beginning Balance	Provision	Forecast Retirements	
1	Gathering plant					
2	443 Gas Holders - Storage	2.00%	(9)	(1)		(10)
3	449 Other local storage equip.	3.00%	(2)	(0)		(2)
4						
5			(11)	(1)		(12)
6	Transmission plant					
7	462 Compressor structures	3.24%	(1,618)	(101)		(1,720)
8	463 Regulating structures	4.50%	(911)	(37)		(947)
9	465 Mains	2.50%	(65,183)	(1,899)		(67,082)
10	466 Compressor equipment	3.61%	(14,754)	(676)		(15,430)
11	467 Regulating equipment	4.61%	(4,415)	(259)		(4,674)
12	468 Communications	6.75%	(2,438)	(82)		(2,520)
13	469 Other	5.33%	(1,066)	(0)		(1,094)
14						
15			(89,320)	(3,054)		(92,374)
16	Distribution plant					
17	472 Structures	3.03%	(104)	(7)		(111)
18	473 Services	3.29%	(13,273)	(338)		(13,611)
19	474 House installations	2.74%	(2,041)	(117)		(2,157)
20	475 Mains	2.25%	(13,814)	(395)		(14,210)
21	477 Regulating equipment	3.57%	(205)	(35)		(239)
22	478 Meters	2.37%	(2,214)	(212)		(2,426)
23	479 Other	5.33%	(174)	(0)		(175)
24						
25			(31,825)	(1,104)		(32,929)
26						
27	General plant					
28	480 Land	0.00%	23			23
29	482 Structures	2.70%	(2,858)	(232)		(3,089)
30	483 Office equipment	4.43%	(351)	(76)		(427)
31	484 Transportation equipment	6.15%	(1,756)	(282)	203	(1,876)
32	485 Heavy work equipment	6.08%	(1,516)	(161)		(1,677)
33	486 Tools	3.17%	(915)	(207)		(1,122)
34	487 Computer equipment	9.30%	(1,022)	(182)		(1,204)
35	488 Communications	9.72%	(504)	(29)		(533)
36	489 Other	5.33%	(1)	(0)		(1)
37			(8,900)	(1,170)	203	(9,907)
38						
39			(130,055)	(5,328)	203	(135,222)
40						
41	Amortization of CIAC		<u>4,366</u>	166		<u>4,532</u>
42						
43	Depreciation capitalized			<u>57</u>		
44						
45	Net Depreciation expense			<u>(5,105)</u>		
46						

Pacific Northern Gas Ltd.
(PNG-West Division)

GAS PLANT IN SERVICE - CONTINUITY OF ACCUMULATED DEPRECIATION

(000's)

<u>Line</u>	<u>Description</u>	<u>Test Yr 2012</u>	<u>Forecast 2011</u>
1	Balance, Beginning of Year	(130,055)	(123,756)
2	CIAC Accumulated Balance, Beginning of Year	<u>4,366</u>	<u>4,208</u>
3	Utility Accumulated Depreciation, Beginning of Year	<u>(125,689)</u>	<u>(119,549)</u>
4	Depreciation Provision:		
5	Plant	(5,328)	(5,665)
6	Contributions in Aid of Construction	166	159
7	Depreciation Adjustment Deferral	<u> </u>	<u> </u>
8	Total Additions	<u>(5,162)</u>	<u>(5,507)</u>
9	Plant Retirements:	0	
10	Normal Course	203	437
11	Extraordinary Plant Loss		
12	CIAC Retirements	-	-
13	Removal Costs	-	-
14	Proceeds on Disposals	(41)	(16)
15	Total Retirements	<u>162</u>	<u>421</u>
16	Balance, End of Year	<u>(130,689)</u>	<u>(124,635)</u>
17	Closing Balance Consists of:		
18	Accumulated Depreciation - Plant	(135,222)	(129,001)
19	Accumulated Amortization - CIAC	<u>4,532</u>	<u>4,366</u>
20	Balance, End of Year	<u>(130,689)</u>	<u>(124,635)</u>

Pacific Northern Gas Ltd.
(PNG-West Division)

CONTRIBUTIONS IN AID OF CONSTRUCTION
(000's)

Line No.	Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	Gas Plant In Service					
2	Beginning balance	9,201	8,993	8,914	8,869	8,792
3	Additions	15	101	59	44	77
4	Ending balance	9,216	9,093	8,993	8,914	8,869
5	Natural Gas Vehicles					
6	Beginning balance	20	20	20	20	20
7	Additions	0	0	0	0	0
8	Ending balance	20	20	20	20	20
9	Accumulated Amortization					
10	Beginning balance	(4,366)	(4,208)	(3,957)	(3,705)	(3,453)
11	Additions	(166)	(160)	(251)	(252)	(252)
12	Ending balance	(4,532)	(4,367)	(4,208)	(3,957)	(3,705)
13	Net Total					
14	Beginning balance	4,855	4,805	4,977	5,185	5,359
15	Additions	(151)	(59)	(192)	(208)	(174)
16	Ending balance	\$4,704	\$4,746	\$4,785	\$4,977	\$5,185
17	Average balance	\$4,779	\$4,776	\$4,881	5,081	5,272

Pacific Northern Gas Ltd.
 (PNG-West Division)

CONSTRUCTION WORK IN PROGRESS
 (000's)

Line No.	Description	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1	Pipe	\$0	\$0	\$0	\$0	\$0
2	Fittings	0	0	0	0	0
3	Transmission materials	0	0	0	0	0
4	Projects under construction	100	100	100	100	100
5	Total	\$100	\$100	\$100	\$100	\$100

Pacific Northern Gas Ltd.
(PNG-West Division)

PENSION CONTRIBUTIONS AND EXPENSE
(000's)

Line No.	Description	Test Year 2012	NSP 2011
1	Cash contributions to plan	\$1,685	\$1,858
2	Expense (recovered in rates)	\$1,514	1,063
3	Additions/(reductions) in B/S asset	\$171	\$171
4			
5			
6	Pension asset/(liability) components		
7	Funding status		
8	Opening balance	(\$9,893)	(\$5,395)
9	Change in funding status	779	(4,498)
10	Closing balance	(\$9,114)	(\$9,893)
11			
12	FIT associated with funding status		
13	Opening balance	\$2,473	\$1,349
14	Change in FIT associated with funding status	(195)	\$1,125
15	Closing balance	\$2,278	\$2,473
16			
17	Accumulated OCI - pension		
18	Opening balance	\$9,418	\$5,450
19	Amortization of OCI - pension	(456)	3,968
20	Closing balance	\$8,962	\$9,418
21			
22	Net after-tax pension asset/(liability) - closing balance	\$2,126	\$1,998
23			
24			
25	Rate Base debit/(credit)		
26	Opening Balance	\$1,906	\$0
27	Pre-tax additions	171	0
28	Current income taxes	(43)	\$0
29	Closing Balance	\$2,035	\$0
30			
31			
32	Average balance	\$1,971	\$0

**Pacific Northern Gas Ltd.
(PNG-West Division)**

**NON-PENSION POST RETIREMENT BENEFITS ("NPPRB")
(000's)**

Line No.	Description	Test Year 2012	NSP 2011
1	Cash contributions to RCA/tax account	\$0	\$420
2	Cash cost of retiree benefits	171	\$164
3	Expense (recovered in rates)	(545)	(584)
4	Change in unfunded status of NPPRB plans	(374)	0
5	Current income taxes	94	0
6	Related future income taxes	(\$94)	\$0
7			
8			
9	NPPRB asset/(liability) components		
10	Funding status		
11	Opening balance	(\$4,602)	(\$4,219)
12	Change in funding status	(274)	(383)
13	Closing balance	(\$4,876)	(\$4,602)
14			
15	FIT associated with funding status		
16	Opening balance	\$1,151	\$1,055
17	Change in FIT associated with funding status	69	96
18	Closing balance	\$1,219	\$1,151
19			
20	Accumulated OCI - NPPRB		
21	Opening balance	\$1,434	\$1,116
22	Amortization of OCI - NPPRB	(75)	318
23	Closing balance	\$1,359	\$1,434
24			
25	Net after-tax NPPRB position - closing	(\$2,298)	(\$2,018)
26			
27			
28	Rate Base debit/(credit)		
29	Opening Balances:		\$0
30	- historical unrecovered NPPRB expense net of tax	\$1,506	
31	- stranded NPPRB transitional obligation net of tax	511	
32	- Net NPPRB position after tax	(2,018)	\$0
33	Jan 1, 2012 amortization of historical unrecovered NPPRB expense & transitional obligations	(2,018)	
34	Pre-tax additions	(374)	0
35	Current income taxes	94	0
36	Closing Balance	(\$2,298)	\$0
37			
38	Average rate base balance	(\$2,158)	\$0

Pacific Northern Gas Ltd.
 (PNG-West Division)

DEFERRED INCOME TAX BALANCES
 (000's)

Line No.	Description	Test Year 2012	NSP 2011
1	Rate Base debit/(credit)		
2	Opening Balances:		
3	- historical recovered deferred income tax expense	(\$9,862)	(\$10,862)
	Jan 1, 2012 amortization of historical recovered		
4	deferred income tax expense	2,018	0
5	Current year amortization	1,000	1,000
6	Closing Balance	(6,845)	(9,862)
7			
8	Average rate base balance	(\$7,345)	(\$10,362)

Pacific Northern Gas Ltd.
(PNG-West Division)

CONTINUITY OF
DEFERRED CHARGES

YEAR 2011
(000's)

Line	Description	Net of tax Actual Balance '10	Future Income Taxes	Gross Actual Balance '10	Gross Additions	Future Income Tax	Gross Amortization	Forecast Balance '11
1	INCLUDED IN RATE BASE							
2	Line break costs	564	200	764	1		174	591
3	Plant Gains and Losses	1,298		1,298	264		27	1,535
4	Investigative Digs	366	149	515	254		50	719
5	RSAM	720	259	979	(1,287)			(308)
6	IFRS / US GAAP	206	83	290	284			573
7	Sub-total: Gross Deferrals Included in Rate Base	<u>3,155</u>	<u>691</u>	3,846	(484)		251	3,111
8	Related Future Income Taxes (FIT)			(691)		198	(59)	(433)
9	Rate Base Deferrals, net of FIT			<u>3,155</u>	<u>(484)</u>	198	192	<u>2,677</u>
10	MID - YEAR RATE BASE							2,916
11	NOT INCLUDED IN RATE BASE:							
12	Pipeline Inspections	185	70	255	(0)		193	61
13	GCVA	(607)	(226)	(833)	893			61
14	Deactivated Facilities				0			0
14	Industrial Customer Deliveries	(21)	(7)	(28)	(58)		(29)	(57)
15	Other Interest Bearing Deferrals	<u>(1,476)</u>	<u>(668)</u>	<u>(2,144)</u>	<u>(2,233)</u>		<u>(1,463)</u>	<u>(2,914)</u>
16	Sub-Total: Gross Interest Bearing Deferrals	<u>(1,918)</u>	<u>(832)</u>	<u>(2,750)</u>	<u>(1,398)</u>		<u>(1,298)</u>	<u>(2,850)</u>
17	Related Future Income Taxes			832		342	382	792
18	Interest Bearing Deferrals, net of FIT			<u>(1,918)</u>	<u>(1,398)</u>	342	(917)	<u>(2,058)</u>
19	Gross Deferrals, excluding Debt Issue Costs & Termination Payment			1,096	(1,883)		(1,047)	261
20	Future Income Taxes on Deferrals, excluding Debt Issue Costs &			141		541	322	359
21	Deferrals (net of FIT), excl. Debt Issue Costs & Termination Payment			<u>1,237</u>	<u>(1,883)</u>	541	(725)	<u>620</u>
22	West Fraser Termination Payment, net of FIT			<u>(3,581)</u>	<u>(133)</u>		<u>(1,276)</u>	<u>(2,439)</u>
23	Debt issue costs	<u>448</u>		<u>448</u>			<u>50</u>	<u>398</u>

Pacific Northern Gas Ltd.
(PNG-West Division)

CONTINUITY OF
DEFERRED CHARGES

TEST YEAR 2012
(000's)

Line	Description	Gross Actual Balance '11	Gross Additions	Future Income Tax	Gross Amortization	Forecast Balance '12
1	INCLUDED IN RATE BASE					
2	Line break costs	591	0		170	422
3	Plant Gains and Losses	1,535	0		135	1,400
4	Investigative Digs	719	373		69	1,024
5	RSAM	(308)	101		0	(207)
6	IFRS / US GAAP	573	113		184	501
7	Sub-total: Gross Deferrals Included in Rate Base	3,111	587	0	558	3,140
8	Related Future Income Taxes (FIT)	(433)		(147)	(106)	(474)
9	Rate Base Deferrals, net of FIT	2,677	587	(147)	453	2,665
10	MID - YEAR RATE BASE					2,671
11	NOT INCLUDED IN RATE BASE:					
12	Pipeline Inspections	61	1		62	0
13	GCVA	61	479		0	540
14	Industrial Customer Deliveries	(57)	(1)		(59)	(0)
15	Other Interest Bearing Deferrals	(2,914)	(137)		(1,194)	(1,857)
16	Subtotal: Gross Interest Bearing Deferrals	(2,850)	342	0	(1,190)	(1,317)
17	Related Future Income Taxes	792		(114)	295	383
18	Interest Bearing Deferrals, net of FIT	(2,058)	342	(114)	(895)	(935)
19	Gross Deferrals, excluding Debt Issue Costs & Termination Payment	261	930	0	(632)	1,823
20	Future Income Taxes on Deferrals, excluding Debt Issue Costs & Termination Payment	359	0	(261)	189	(92)
21	Deferrals (net of FIT), excluding Debt Issue Costs & Termination	620	930	(261)	(443)	1,731
22	West Fraser Termination Payment, net of FIT	(2,439)	(103)	0	(1,289)	(1,252)
23	Debt issue costs	398	0	0	48	350

Details of Interest Bearing non Rate Base Deferral Accounts
(000's)

	Net of tax Dec 10	Future Income Taxes	Gross Actual Balance '10	11 Additions	11 Tax	11 Amort	Gross Dec 11	Jan 1/12	12 Additions	12 Tax	12 Amort	Gross Dec 12
1 BCUC Fees	2	0	2	(19)		2	(19)	(19)	(0)		(19)	(0)
2 BCUC Proceedings	6	2	8	0		4	4	4	0		4	0
3 Property Tax Variance	(34)	(15)	(49)	(14)		(47)	(16)	(16)	(0)		(17)	0
4 Short term interest	25	9	34	(8)		14	12	12	0		12	(0)
5 Long term interest	(58)	(24)	(82)	(53)		(84)	(51)	(51)	(1)		(52)	(0)
6 CAP/ROE Hearing	63	26	89	2		88	3	3	0		3	0
7 Propane Air Plant	198	70	268	8		54	222	222	7		78	150
8 2011 Depreciation Adjustment			0	(47)		0	(47)	(47)	(1)		(49)	(0)
9 Old Revolving Debt Issue Costs	86	0	86	2		88	(0)	(0)	(0)		(0)	0
10 LNG Partners Option Fee Payment	(1,763)	(737)	(2,500)	(2,103)		(1,582)	(3,021)	(3,021)	(142)		(1,155)	(2,008)
11 Non-Rate Base Deferrals	(1,476)	(668)	(2,144)	(2,233)	0	(1,463)	(2,914)	(2,914)	(137)	0	(1,194)	(1,857)
12 Related Future Income Taxes			668		567	425	810	810		0	297	512
13 Other Rate Base Def., net of FIT			(1,476)	(2,233)	567	(1,038)	(2,105)	(2,105)	(137)	0	(897)	(1,345)

Details of West Fraser Termination Payment Deferral Account
(000's)

	Net of tax Dec 10	Future Income Taxes	Gross Actual Balance '10	11 Additions	11 Tax	11 Amort	Gross Dec 11	Jan 1/12	12 Additions	12 Tax	12 Amort	Gross Dec 12
14 Termination Payment Principal	(3,581)	(1,427)	(5,009)			(1,554)	(3,455)	(3,455)			(1,703)	(1,752)
15 Add Interest at ST debt rate	0			(133)	0	(133)	0	0	(103)	0	(103)	0
16 Sub-total Termination Payment	(3,581)	(1,427)	(5,009)	(133)	0	(1,687)	(3,455)	(3,455)	(103)	0	(1,806)	(1,752)
17 Related Future Income Taxes			1,427			412	1,016	1,016			516	499
18 Termination Payment, net of FIT			(3,581)	(133)	0	(1,276)	(2,439)	(2,439)	(103)	0	(1,289)	(1,252)
19 Amortization included in Revenue (before tax)						(1,687)					(1,806)	
20 Future Income taxes on Termination Payment						412					516	

Pacific Northern Gas Ltd.
 (PNG-West Division)

CASH WORKING CAPITAL

FOR THE YEAR ENDED DECEMBER 31, 2012
 (000's)

Line No.	Description	Lag/(Lead) Days	Expense	Working Capital
1	Revenue	51.6		
2	Expense	(27.2)		
3	Operating working capital	<u>24.4</u>	35,867	\$2,398
4	Adjustments:			
5	Budget Billing Plan			(\$793)
6	Carbon Tax			\$20
7	Insurance Receivable			\$0
8	HST			<u>\$158</u>
9	Cash working capital			<u><u>\$1,782</u></u>

Pacific Northern Gas Ltd.
(PNG-West Division)

REVENUE LAG DAYS

FOR THE YEAR ENDED DECEMBER 31, 2012
(000's)

Line No.	Revenues	Revenue Lag Days	Revenue	Extended 2010 Revenue
1	Residential - monthly (1)	47.0	\$7,529	353,650
2	- bimonthly	61.2	\$14,409	881,553
3	Small commercial - monthly (2)	46.3	7,885	365,172
4	- bimonthly	61.4	4,434	272,046
5	Large commercial - firm	44.2	521	23,011
6	- transport	44.2	2,635	116,482
7	- interruptible	44.2	230	10,171
8	Off - peak (Rate 6)	44.2	190	8,408
9	NGV (Rate 7)	44.2	88	3,892
10	Small industrial - sales	44.2	1,540	68,078
11	- transport	42.2	1,931	81,481
12	Large industrial	31.2	2,301	71,791
13	<i>Weighted Average</i>	51.6	43,694	2,255,735
14	Revenue Deficiency	51.6	886	45,728
15	Other operating revenue	51.6	3,196	165,018
16	Average revenue lag days	51.6	\$47,776	2,466,481
17	Working Capital	<u>51.6</u> 365	47,776	\$6,754

18 Note 1: 65.7% billed bimonthly, 34.3% billed monthly

19 Note 2: 36% billed bimonthly, 64% billed monthly

Pacific Northern Gas Ltd.
(PNG-West Division)

EXPENSE LEAD DAYS

FOR THE YEAR ENDED DECEMBER 31, 2012
(000's)

Line No.	Expenses	Expense (Lead) Days	Normalized Expense	Extended 2010 Expense
1	Gas purchases - baseload	(40.2)	\$1,203	(48,370)
2	Gas purchases - seasonal	(40.2)	\$10,539	(423,672)
3	Coloured gasoline tax	(30.4)	22	(672)
4	Carbon Tax Co Use	(43.4)	90	(3,899)
5	Operating payrolls	(5.0)	7,829	(39,147)
6	Employee benefits	(20.9)	3,317	(69,316)
7	Spectra service agreement	(40.2)	259	(10,412)
8	Employee expenses	(4.9)	603	(2,954)
9	Uncollectible accounts	(51.6)	100	(5,160)
10	Other operating expenses	(31.4)	5,486	(172,246)
11	Transfers to capital	8.3	(981)	(8,142)
12	Insurance	182.5	736	134,303
13	Property taxes	(1.0)	3,696	(3,696)
14	Provincial capital tax	(58.6)	0	0
15	Franchise fees	(242.5)	1,220	(295,850)
16	Income taxes payable	(15.2)	1,748	(26,573)
17	Average expense lag days	<u>(27.2)</u>	<u>\$35,867</u>	<u>(975,806)</u>
18	Working Capital	<u>(27.2)</u> 365.0	35,867	(\$2,673)

Pacific Northern Gas Ltd.
(PNG-West Division)

CASH WORKING CAPITAL - HST

FOR THE YEAR ENDED DECEMBER 31, 2012
(000's)

Line No.	Description	Taxable Amount	HST @ 12%	Receipt Lag Days	Payment (Lead) Days	Net Lag/(Lead)	Working Capital
1	Revenues						
2	Residential, small commercial & other	\$40,232	4,828	17.6	(30.4)	(12.8)	(169.2)
3	Banner billed customers						
4	Industrial & other manually billed customers	4,348	522	21.0	(60.8)	(39.8)	(56.9)
5	Franchise fee	1,220	146	18.0	(33.4)	(15.4)	(6.2)
6	Carbon Tax	3,098	372	17.3	(30.4)	(13.1)	(13.3)
7							
8		<u>\$48,898</u>	<u>\$5,868</u>			<u>(15.3)</u>	<u>(245.6)</u>
9							
10							
11							
12				Recovery	Payment	Net	
13				<u>Lag Days</u>	<u>(Lead) Days</u>	<u>Lag/(Lead)</u>	
14	Residential point of sale rebate	<u>\$22,372</u>	<u>\$1,566</u>	51.4	(17.6)	33.8	145.0
15							
16							
17							
18				Recovery	Payment	Net	
19				<u>Lag Days</u>	<u>(Lead) Days</u>	<u>Lag/(Lead)</u>	
20	Purchases						
21	Capital expenditures	\$3,107	373	30.4	8.2	38.6	39
22	Gas supply (baseload & seasonal)	11,742	1,409	60.8	(25.0)	35.8	138
23	Operating costs	5,745	689	30.4	8.2	38.6	73
24	Employee expenses	603	72	30.4	8.2	38.6	8
25							
26		<u>\$21,197</u>	<u>\$2,544</u>			<u>37.0</u>	<u>258</u>
27							
28						<u>158</u>	

Pacific Northern Gas Ltd.
(PNG-West Division)

CASH WORKING CAPITAL - CARBON TAX

FOR THE YEAR ENDED DECEMBER 31, 2012
(000's)

Line No.	Description	Taxable GJs	Carbon Tax	Receipt Lag Days	Payment (Lead) Days	Net Lag/(Lead)	Working Capital
1	Gas sales subject to Carbon Tax						
2	Residential sales - January to June	691 611	\$859	15.9	(15.0)	0.9	\$2
3	- July to December	523 304	780	15.9	(15.0)	0.9	2.0
4	Commercial sales - Banner billed - January to June	481 925	598	16.4	(15.0)	1.4	2.3
5	- July to December	385 543	574	16.4	(15.0)	1.4	2.2
6	Commercial sales - manually billed - January to June	0	-	29.0	(45.4)	(16.4)	0.0
7	- July to December	0	-	29.0	(45.4)	(16.4)	0.0
8	Small Industrial sales - January to June	111 933	139	29.0	(15.0)	14.0	5.3
9	- July to December	99 717	149	29.0	(15.0)	14.0	5.7
10	Large Industrial sales - January to June	0	-	16.0	(45.4)	(29.4)	0.0
11	- July to December	0	-	16.0	(45.4)	(29.4)	0.0
12							
13	Carbon Tax Total	2 294 033	\$3,098			2.3	\$19.6

Pacific Northern Gas Ltd.
 (PNG-West Division)

OTHER WORKING CAPITAL ITEMS
 FOR THE YEAR ENDED DECEMBER 31, 2012
 (000's)

Line No.	Description	Transmission Line Pack	Inventories	Total
1	MONTH END BALANCES			
2	January	854	940	1,794
3	February	854	789	1,642
4	March	854	789	1,643
5	April	854	808	1,662
6	May	854	790	1,644
7	June	854	767	1,621
8	July	854	784	1,637
9	August	854	788	1,642
10	September	854	749	1,602
11	October	854	756	1,610
12	November	854	729	1,583
13	December	854	711	1,565
14	Total	<u>\$10,243</u>	<u>\$9,401</u>	<u>\$19,644</u>
15	Average balance	<u>\$854</u>	<u>\$783</u>	<u>\$1,637</u>

**Pacific Northern Gas Ltd.
(PNG-West Division)**

INCOME TAXES

**SCHEDULE 3
(000'S)**

Line No.	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008	Source
1	Calculation of Taxable Income					
2	\$12,211	\$12,450	\$12,074	\$12,365	\$11,835	Tab 1, page 1, line 33
3	(4,839)	(4,999)	(4,369)	(4,215)	(4,762)	Tab 5, page 1, lines 1, 3, 6 & 8
4	72	69	153	137	173	
5	(451)	(595)	915	800	499	Tab 3, page 1, line 24
6						
7	<u>\$6,993</u>	<u>\$6,925</u>	<u>\$8,773</u>	<u>\$9,088</u>	<u>\$7,744</u>	
8						
9	Calculation of Income Tax Expense					
10	1,748	1,835	2,500	2,726	2,401	
11	0	0	0	0	9	
12	(1,000)	(1,000)	(900)	(900)	(900)	
13						
14	<u>\$748</u>	<u>\$835</u>	<u>\$1,600</u>	<u>\$1,826</u>	<u>\$1,510</u>	
15						
16	Particulars of Timing Differences					
17	A. Tax Effects Subject To Flowthrough					
18	5,105	5,337	6,795	6,678	6,522	Tab 2, page 6, line 45
19	(632)	(1,016)	714	722	825	Tab 2, page 13, line 20
20	(4,924)	(4,916)	(5,160)	(5,318)	(5,335)	
21	0	0	(1,435)	(1,282)	(1,513)	
22	0	(0)		0		
23						
24	(451)	(595)	915	800	\$499	
25	B. Tax Effects Subject To Deferral					
26	4,000	3,774	3,158	3,000	2,903	
27						
28	<u>\$3,549</u>	<u>3,179</u>	<u>4,073</u>	<u>3,800</u>	<u>\$3,402</u>	
29						
30	25.00%	26.50%	28.50%	30.00%	31.00%	

Pacific Northern Gas Ltd.
 (PNG-West Division)

COMMON EQUITY

SCHEDULE 4
 ('000's)

Line No.	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008	Source
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						Tab 5, page 1, line 16
25						
26						
27						
28						

Pacific Northern Gas Ltd.
(PNG-West Division)

RETURN ON CAPITAL

SCHEDULE 5
(000's)

Line No.		Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008	Source
1	Short Term Debt	\$10,512	\$6,942	(\$2,261)	(\$13,225)	(\$7,296)	
2	proportion	7.89%	5.31%	-1.79%	-10.24%	-5.59%	
3	rate of return	6.13%	5.11%	5.87%	4.00%	2.83%	Tab 5, page 2, line 12
4	return component	0.48%	0.27%	-0.10%	-0.41%	-0.16%	
5							
6	Long term debt	\$57,750	\$60,003	\$53,453	\$60,501	\$57,966	Tab 5, page 4, line 72
7	proportion	43.35%	45.87%	42.25%	46.83%	44.43%	
8	rate of return	7.26%	7.74%	8.42%	7.84%	8.57%	Tab 5, page 4, line 74
9	return component	3.15%	3.55%	3.56%	3.67%	3.81%	
10							
11	Preferred shares	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000	
12	proportion	3.75%	3.82%	3.95%	3.87%	3.83%	
13	rate of return	7.01%	7.01%	7.01%	7.01%	7.01%	
14	return component	0.26%	0.27%	0.28%	0.27%	0.27%	
15							
16	Common equity	\$59,942	\$58,864	\$70,321	\$76,921	\$74,809	
17	proportion	45.00%	45.00%	55.58%	59.54%	57.33%	
18	rate of return	10.15%	10.15%	8.18%	7.16%	6.97%	
19	return component	4.57%	4.57%	4.55%	4.26%	3.99%	
20							
21	Total capitalization	<u>\$133,205</u>	<u>\$130,808</u>	<u>\$126,514</u>	<u>\$129,197</u>	<u>\$130,479</u>	
22							
23	Return on rate base	<u>8.46%</u>	<u>8.66%</u>	<u>8.28%</u>	<u>7.80%</u>	<u>7.91%</u>	
24							
25	Utility rate base	<u>\$133,205</u>	<u>\$130,808</u>	<u>\$126,514</u>	<u>\$129,197</u>	<u>\$130,479</u>	Tab 2, page 1, line 23

Pacific Northern Gas Ltd.
(PNG-West Division)

SHORT TERM DEBT

FOR THE YEAR ENDED DECEMBER 31
(000's)

	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008	
1 Customer Security Deposits						
2	Average annual balance	\$874	\$880	\$864	\$813	819
3	Interest rate applicable to deposits	1.79%	0.69%	0.24%	0.24%	2.67%
4	Annual Interest Expense	16	6	2	2	22
5						
6 Operating Line / Other						
7	Average annual draw	\$9,638	\$6,062	(\$3,124)	(\$14,038)	(\$8,115)
8	Interest rate	5.54%	4.44%	4.31%	3.78%	2.82%
9	Annual Interest Expense	534	269	(\$135)	(\$531)	(\$229)
10	Other expenses*	95	80			
11						
12	Average short term interest rate	6.13%	5.11%	5.87%	4.00%	2.83%

Pacific Northern Gas Ltd.
(PNG-West Division)

LONG TERM DEBT

FOR THE YEAR ENDED DECEMBER 31
(000's)

	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
1 Secured Debentures Series 2011					
2 Liability beginning of year	\$0	\$5,000	\$5,799	\$6,599	\$7,299
3 Sinking fund payments	0	(5,000)	(800)	(800)	(700)
4 Average Capitalization	0	4,726	5,756	6,556	7,261
5 Annual Interest Expense	0	512	619	705	781
6 Issue costs beginning of year	0	(8)	(9)	(15)	(23)
7 Amortization of Issue Costs	0	(8)	(9)	(6)	(8)
8					
9 Effective Cost Rate	10.93%	10.93%	10.93%	10.93%	10.93%
10					
11					
12 Secured Debentures Series 2018					
13 Liability beginning of year	\$10,324	\$10,832	\$11,340	\$11,848	\$12,355
14 Non-utility portion	(\$786)	(\$824)	(\$863)	(\$902)	(\$940)
15 Utility liability beginning of year	9,539	10,008	10,477	10,946	11,415
16 Sinking fund payments	(469)	(469)	(469)	(469)	(469)
17 Average Capitalization	9,478	9,947	10,416	10,885	11,355
18 Annual Interest Expense	832	870	911	952	994
19 Issue costs beginning of year	(57)	(65)	(44)	(54)	(65)
20 Amortization of Issue Costs	9	9	9	10	11
21					
22 Effective Cost Rate	8.89%	8.89%	8.89%	8.89%	8.89%
23					
24 Secured Debentures Series 2025					
25 Liability beginning of year	\$16,000	\$16,500	\$17,000	\$17,500	\$18,000
26 Sinking fund payments	(500)	(500)	(500)	(500)	(500)
27 Average Capitalization	15,771	16,271	16,771	17,271	17,771
28 Annual Interest Expense	1,471	1,513	1,560	1,606	1,653
29 Issue costs beginning of year	(130)	(138)	(85)	(99)	(114)
30 Amortization of Issue Costs	8	8	8	13	15
31					
32 Effective Cost Rate	9.43%	9.43%	9.43%	9.43%	9.43%
33					
34 Secured Debentures Series 2027					
35 Liability beginning of year	\$17,000	\$17,500	\$18,000	\$18,500	\$19,000
36 Non-utility portion	(\$3,148)	(\$3,241)	(\$3,334)	(\$3,426)	(\$3,519)
37 Utility liability beginning of year	13,852	14,259	14,666	15,074	15,481
38 Sinking fund payments	(407)	(407)	(407)	(407)	(407)
39 Average Capitalization	13,818	14,226	14,633	15,040	15,448
40 Annual Interest Expense	956	982	1,010	1,038	1,066
41 Issue costs beginning of year	(94)	(99)	(69)	(78)	(88)
42 Amortization of Issue Costs	6	5	5	9	10
43					
44 Effective Cost Rate	6.99%	6.99%	6.99%	6.99%	6.99%

Pacific Northern Gas Ltd.
(PNG-West Division)

LONG TERM DEBT

FOR THE YEAR ENDED DECEMBER 31
(000's)

	Test Year 2012	NSP 2011	Actual 2010	Actual 2009	Actual 2008
45					
46	Secured Debentures Series 2017				
47	Liability beginning of year	\$3,573	\$3,893	\$4,000	\$4,000
48	Issue during year	0	0	0	0
49	Sinking fund payments	(320)	(320)	(400)	0
50	Average Capitalization	3,413	3,733	3,979	4,000
51	Annual Interest Expense	146	156	132	134
52	Issue costs beginning of year	(24)	(30)	(37)	(44)
53	Amortization of Issue Costs	6	6	7	7
54					
55	Effective Cost Rate	4.43%	4.37%	3.51%	3.53%
56					
57	Revolving Term Facility				
58	Liability beginning of year	\$16,000	\$16,000	\$6,000	\$6,000
59	Issue during year	14,000	12,000	10,000	3,000
60	Sinking fund payments	0	0	0	(3,000)
61	Average Capitalization	28,911	22,833	11,934	6,748
62	PNG(N.E.) portion	(13,642)	(11,733)	(10,037)	
63	PNG-West portion	15,269	11,100	1,897	
64	Annual Interest Expense	822	502	103	174
65	Stand-by Fees	5	38	82	46
66	Issue costs beginning of year	(68)	(79)	(83)	(154)
67	Amortization of Issue Costs	18	11	8	18
68					
69	Effective Cost Rate	4.90%	4.97%	10.67%	3.53%
70					
71	Total Long Term Debt				
72	Total Average Capitalization	57,750	60,003	53,453	60,501
73					
74	Effective Cost Rate	7.26%	7.74%	8.42%	7.84%

PACIFIC NORTHERN GAS LTD

CODE OF CONDUCT

**For Provision of Utility Resources and Services
To Non-Regulated Businesses and Affiliates
*(November 2011)***

PNG CODE OF CONDUCT (November 2011)

SCOPE

This Code of Conduct (COC) governs the provision by Pacific Northern Gas Ltd. (PNG), a utility regulated by the British Columbia Utilities Commission (Commission), of utility resources and services to PNG's non-regulated businesses and affiliates (for ease of reference, jointly referred to herein as NRBs). This COC applies to the conduct of PNG's wholly-owned subsidiary Pacific Northern Gas (N.E.) Ltd. [PNG(N.E.)], also a utility regulated by the Commission. This COC was drafted having regard to the Commission's "Retail Markets Downstream of the Utility Meter" Guidelines of April, 1997 (Guidelines). The Commission Code of Conduct Principles from the Guidelines are attached as Appendix A.

This COC is being drafted in the context of PNG's current corporate structure where its NRBs are owned directly by PNG. Currently, PNG(N.E.) does not own any interest in an NRB. Further, PNG is only developing and operating renewable power projects through its NRBs and has no intention of participating in retail markets downstream of the utility meter. Should these circumstances change, PNG will file amendments to this COC with the Commission as may be required to reflect the impact of changed circumstances.

PNG is filing a Transfer Pricing Policy dated November 2011 (TPP) with the Commission concurrently with the filing of this COC. The TPP will be used in conjunction with this COC to establish pricing for the utility resources and services provided by PNG to its NRBs, other than PNG(N.E.) which is an affiliate of PNG. The services provided by PNG to PNG(N.E.) are covered by a shared services arrangement which is reviewed regularly by the Commission.

APPLICATION OF COMMISSION PRINCIPLES

1. Shared Services and Personnel

This COC recognizes the potential benefits to PNG of using its employees to provide services to NRBs.

PNG may provide services to NRBs, including supervision and management, while ensuring that ratepayers will not be negatively impacted by the provision of PNG of those utility services. The costs of providing such services will be determined in accordance with the TPP.

NRBs may contract PNG utility personnel provided PNG complies with Section 3 of this COC, Provision of Information by PNG, and no conflict of interest exists which will negatively impact ratepayers.

PNG CODE OF CONDUCT (November 2011)

2. Price for Provision of Utility Resources and Services

The price for the provision of services by PNG to NRBs shall be determined in accordance with the TPP. PNG will comply with acceptable business practices if it wishes to purchase assets, goods or services from an NRB.

3. Provision of Information by PNG

PNG will not provide to an NRB any information that would inhibit a competitive energy services market from functioning.

The following should act as a guideline for employees confronted with issues related to the sharing of confidential information:

- a) This COC precludes PNG from releasing confidential customer specific information without the consent of that customer. If a customer agrees to a general release of customer specific information, that information must be made available to any market participant who requests it and is willing to pay costs associated with the provision of the information, without discrimination as to access, timing, cost or content. If a customer requests customer specific information be provided to a specific market participant, only that participant may receive the information, subject to payment of associated costs incurred to provide the information.
- b) PNG may disclose to any market participant that requests it and is willing to pay the appropriate transfer price, customer information that is aggregated or summarized in such a way that confidential information would not ordinarily be ascertained by third parties.
- c) PNG may provide or sell any non-customer specific information to any market participant that requests it and is willing to pay the appropriate transfer price.

4. Preferential Treatment

PNG will not state or imply that favoured treatment will be available to its customers as a result of using any service of an NRB. In addition, no PNG personnel will condone or acquiesce in any other person stating or implying that favoured treatment will be available to PNG's customers as a result of using any product or service of an NRB.

PNG CODE OF CONDUCT (November 2011)

5. Equitable Access to Services

Except as required to meet acceptable quality and performance standards, and except for some specific assets or services which require special consideration as approved by the Commission, PNG will not preferentially direct customers seeking competitively offered services to an NRB or a specific retailer.

6. Compliance and Complaints

PNG will advise all of its employees of their expected conduct pertaining to this COC, with annual updates for employees who may be directly involved with NRB activities.

PNG will monitor employee compliance with this COC by conducting compliance reviews from time to time. The results of a compliance review will be set forth in a report to be filed with the Commission within 60 days of the completion of each such report. These reviews will be performed annually unless otherwise directed by the Commission.

Complaints made to PNG by third parties about the application of this COC, or any alleged breach thereof, will be promptly investigated by PNG's senior management. PNG will notify the complainant and the Commission in writing of the results of the investigation, including a description of any course of action which will be or has been taken promptly following the completion of the investigation. PNG will endeavour to complete this investigation within 30 days of the receipt of the complaint.

Where PNG determines that the complaint is unfounded, PNG may apply to the Commission for reimbursement of the costs of the investigation from the third party initiating the complaint or where this is not possible, for inclusion of those costs in rates.

7. Financing and Other Risks

PNG will not undertake any financing or other financial assistance on behalf of an NRB that exposes utility ratepayers to additional costs or risks, unless appropriate compensation is received by PNG for such financing or other financial assistance, and such financing or other financial assistance is approved by the Commission.

8. Use of Utility Name

PNG agrees that newly established NRBs will not use PNG's name as the primary identifier within British Columbia, and will not use PNG's name in a manner that indicates that PNG's utility resources will support the NRB.

PNG CODE OF CONDUCT (November 2011)

9. Amendments

In order to ensure that this COC remains workable and effective, PNG will review the provisions of this COC on an ongoing basis and as required by the Commission, but with a maximum of three years between reviews.

Amendments to this COC may be made from time to time as approved by the Commission.

PNG CODE OF CONDUCT (November 2011)

APPENDIX A

COMMISSION CODE OF CONDUCT PRINCIPLES

The Commission has established the following code of conduct principles in the Guidelines:

- i) The regulated company will not provide to the NRB any market-sensitive or confidential information that would inhibit a competitive energy services market from functioning. If customers agree to a release of customer information to the NRB, it should be provided to other market participants under the same terms and conditions and for the same price. Should an individual customer make a specific request to have information released to a particular third party, it will be released to that party only. The utility will be able to recover from the customer the costs associated with the provision of this information.
- ii) No regulated company personnel will state or imply that favoured treatment will be available to customers of the company as a result of using any service of an NRB. In addition, no regulated company personnel will condone or acquiesce in any other person stating or implying that favoured treatment will be available to customers of the company as a result of using any service of an NRB.
- iii) No regulated company personnel will preferentially direct customers seeking competitively offered services to an NRB. If a customer, or potential customer, requests from the regulated company information about products or services offered by an NRB or its competitors in downstream markets, the regulated company may provide such information, including a directory of retailers of the product or service, but shall not promote any specific retailer in preference to any other retailer.
- iv) The regulated company will formally advise all employees of expected conduct related to these principles and it will undertake to perform periodic audits of the relationships to ensure compliance with these principles. These audits will be performed no less than once a calendar year and filed with the Commission.
- v) Complaints by non-affiliated parties about the application of these principles, or any alleged breach thereof, will be brought to the immediate attention of the senior management of the regulated company and subsequently a report of the complaints, and action taken, will be filed with the Commission. The report will be filed with the Commission within one month of the complaint being made.
- vi) The financing of the utility and NRB will be accounted for entirely separately with the financing costs reflecting the risk profile of each entity. No cross-guarantees or any form of financial assistance whatsoever should be provided directly or indirectly by a utility to its NRB without approval of the Commission.

PNG CODE OF CONDUCT (November 2011)

vii) Use of the utility name by a related NRB will require approval by the Commission to ensure that its use will not interfere with the Commission's ability to protect ratepayers.

In those cases where retail customers have direct market access to the commodity, the utility's code of conduct will also include the following provision,

viii) The regulated company will treat all requests for distribution system access for the purpose of direct commodity marketing equitably and according to the requirements approved for direct commodity marketing in British Columbia.

PACIFIC NORTHERN GAS LTD.

TRANSFER PRICING POLICY

For Provision of Utility Resources and Services

To Non-Regulated Businesses and Affiliates

(November 2011)

PNG TRANSFER PRICING POLICY (November 2011)

Scope

This Transfer Pricing Policy (TPP) addresses the pricing of resources and services provided by Pacific Northern Gas Ltd. (PNG), a utility regulated by the British Columbia Utilities Commission (Commission), to non-regulated businesses and affiliates (for ease of reference, jointly referred to herein as “NRBs”). This TPP has been drafted giving regard to the Commission’s “Retail Markets Downstream of the Utility Meter” Guidelines of April, 1997 (Guidelines). The Commission’s transfer pricing principles from these Guidelines are attached as Appendix A.

Further, this TPP has been drafted in the context of PNG’s current corporate structure where its NRBs are owned directly by PNG. At this time, PNG’s involvement in NRBs consists mainly in developing and operating renewable power projects.

This TPP applies equally to the conduct of PNG’s wholly-owned subsidiary, Pacific Northern Gas (N.E.) Ltd. [PNG(N.E.)], also a utility regulated by the Commission. Currently, PNG(N.E.) is not involved in NRBs.

PNG is filing a Code of Conduct dated November 2011 (COC) with the Commission concurrently with the filing of this TPP. This TPP will be applied in conjunction with the COC to ensure that PNG receives adequate compensation for resources and services provided to NRBs, thereby protecting ratepayers from subsidizing activities carried out by PNG that are not related to its utility services to its utility customers. The services provided by PNG to PNG(N.E.) are covered by a shared services arrangement which is reviewed regularly by the Commission. Therefore the TPP will not apply to PNG services rendered to PNG(N.E.).

PNG TRANSFER PRICING POLICY (November 2011)

Policy

Transfer prices charged to NRB activities by PNG will ensure PNG ratepayers are not adversely affected and will be established using the following principles:

1. Pricing Rules

- i. The transfer price for resources and services will be set at full cost (see Section 4 below).
- ii. In situations where it can be shown that an alternative transfer price will provide greater benefits to the ratepayer, PNG may apply to the Commission for special pricing consideration.

2. Resources and Services

For the most part, the types of resources and services that can be provided to NRBs by PNG are human resources and associated facilities. Though not envisioned at this time, instances may occur where PNG vehicles or other equipment are used for NRB activities.

Notwithstanding the resources and services described above, any resources or services that are directly used for NRB activities will be separately accounted for and charged directly to the appropriate entity or activity, including third-party costs and other incremental expenditures.

If other utility resources or services are used by an NRB that are not described by this policy, then PNG will make an application to the Commission on a case-by-case basis. An example of this would be the determination of costs for a PNG asset permanently transferred to an NRB.

3. Service Term

Resources and services will be provided by PNG to NRBs on an “as required” basis. “As required” means that the resources and services are not specifically committed to the NRB. PNG will record the cost of the actual employee time incurred to perform the work to the receiving entity (i.e. the NRB). As part of its annual budgeting process, PNG will estimate resource and service requirements related to NRB activities.

PNG TRANSFER PRICING POLICY (November 2011)

4. Determining Full Costs

For the purposes of this TPP, full cost for the resources or services provided by PNG to an NRB will be based on PNG's costs as described below.

4.1 Human Resources

PNG will track actual employee time incurred to perform work in connection with NRB activity. The full cost of providing service to NRBs includes direct labour costs as well as benefits loadings and corporate facilities and overhead loadings applied to the direct labour costs.

4.2 Vehicle Usage

PNG will track actual vehicle usage in connection with NRB activity and this use will be charged out on an hourly basis. The vehicle class will determine the appropriate charge-out rate. The charge out rate is calculated to recover fleet operating expenses and is based on forecast utilization of the vehicles.

4.3 Other Large Assets

Should there be significant usage of other larger value assets for NRB activity, specific charges related to the asset would be allocated to the NRB (operating and maintenance costs).

5. Research and Development Activities

5.1 Research Costs

As research is regarded as a continuing activity required to maintain PNG's business and its effectiveness, such expenses shall be borne by PNG. However, where it is evident that certain research activities are clearly directed towards specific non-regulated pursuits, PNG will ensure that these activities are identified as NRB activities and that the cost of these activities, determined according to the pricing rules defined in Section 4, net of any quantifiable benefits received by PNG, is tracked and excluded from PNG's cost of service for rate making purposes.

5.2 Development Costs

Development costs for new non-regulated products and services will be tracked and recorded as NRB activities according to the pricing rules defined in Section 4, net of any quantifiable benefits received by PNG, and excluded from PNG's cost of service for rate making purposes.

PNG TRANSFER PRICING POLICY (November 2011)

5.3 Transfer of Costs

Research and development activities initially undertaken within PNG may, from time to time, be transferred to an NRB with Commission approval. If the underlying cost of these activities was historically excluded from PNG's cost of service no further benefit will be conferred to PNG ratepayers on the transfer of these costs. If the underlying cost of these activities was historically included in PNG's cost of service for rate making purposes, the NRB shall reimburse PNG for these costs using the appropriate pricing rules as defined in Section 4.

Costs associated with transferring an activity to an NRB, and the start-up of NRB activities, shall be borne by the NRB. To the extent that these activities involve PNG resources during the transfer, the NRB shall reimburse PNG using the appropriate pricing rules as defined in Section 4. Costs relating to the termination of an activity within PNG shall be borne by PNG.

6. Cost Collection Procedures

PNG will be responsible for establishing and monitoring processes to ensure that the appropriate employees charge all time spent engaged in NRB activities. These processes will ensure that all related vehicle and equipment use for NRB activities is also captured. PNG's corporate accounting group will be responsible for administration of these processes.

6.1 Time Sheets

Individuals performing service for NRBs must report all time spent on that service by coding their time to the appropriate NRB activity. Time sheets are to be sent monthly to the immediate supervisor or PNG's Payroll Department. The NRB shall also review the validity of these time sheets.

The methodology for determining a labour cost for time charges is on the basis of the average pay (includes base and incentive pay) in the case of management and exempt employees or the exact wage grade in the case of bargaining unit employees.

6.2 Labour Cost Loadings

Loadings are defined as the recovery of costs that, by their nature, would be administratively prohibitive to charge directly to each business activity. Loadings will be based on the expected actual cost of the expense and allocated on a reasonable and consistent basis. Where applicable, loadings will be the same as those used for all other PNG activities.

Benefits Loading

All regular labour charged to NRB activities will attract a benefit loading calculated to recover the cost of employee benefits over hours available for work. Benefit costs include pension plan contributions, savings plan contributions, statutory benefit contributions, flexible benefit contributions and other items. See Schedule 1 for current loading rates

PNG TRANSFER PRICING POLICY (November 2011)

Corporate Facilities and Overhead Loadings

All regular labour charged to NRB activities will also attract a corporate facilities and overhead loading calculated to recover the cost of office facilities and supplies and general corporate costs over hours available for work. Facilities costs include office rent, utilities, office supplies and other items. Corporate costs include director fees, exchange and listing fees and other corporate costs. See Schedule 1 for current loading rates.

6.3 Vehicle and Equipment Charges

Vehicle and equipment use generally follows the time recorded by field employees assigned to a particular vehicle or unit of equipment. When field staff members allocate time to NRB activities, the cost of any vehicles or equipment used in these activities will also be charged to the NRB activity.

Vehicle and equipment use charges will be based on actual use for NRB activities and this use will be charged out on an hourly basis. The vehicle and equipment class will determine the appropriate charge-out rate and charge-out rates will be the same as those used for all other PNG activities.

6.4 Invoicing

On a quarterly basis, the NRB activity will be invoiced or allocated costs of services and resources provided during the period.

7. Budgeting for Services

PNG will estimate or forecast NRB service levels as part of the revenue requirements application process. These estimates or forecasts will be consistent with the relevant costs and assumptions contained in the applicable application. In addition, this process will include a review and update of all numerical inputs and cost assumptions used to calculate loading rates.

8. Financing and Other Risks

PNG will not undertake any financing or other financial assistance on behalf of an NRB that exposes utility ratepayers to additional costs or risks, unless appropriate compensation is received by PNG for such financing or other financial assistance, and such financing or other financial assistance is approved by the Commission.

PNG TRANSFER PRICING POLICY (November 2011)

9. Review and Amendments

In order to ensure that this TPP remains workable and effective, PNG will review the provisions of this TPP on an ongoing basis as part of the COC compliance review and as required by the Commission, with a maximum of three years between reviews. However, PNG may make application to the Commission for approval of changes to this TPP, including the pricing rules and the formula for determining full costs as and when required.

PNG TRANSFER PRICING POLICY (November 2011)

SCHEDULE 1

LOADING RATES

Benefits Loading			37.6%	
Corporate Facilities and Overhead Loading			28.7%	
Note:	The above rates are the rates in effect at the time of writing of this policy.			
	Actual rates may be adjusted from time to time to ensure appropriate recovery of costs.			
Example:	Determining Cost for Service for Employee at Daily Pay of \$300			
Base Pay (Daily):			\$ 300.00	
Plus: Benefits @	37.6%		112.79	
Plus: Corporate Facilities and Overhead @	28.7%		86.15	
Total employee cost per day			<u>\$ 498.94</u>	
Cost Ratios:	To base pay		1.66	
	To loaded labour		1.21	

PNG TRANSFER PRICING POLICY (November 2011)

APPENDIX A

TRANSFER PRICING PRINCIPLES

The British Columbia Utilities Commission (Commission) has established the following transfer pricing principles in the “Retail Markets Downstream of the Utility Meter” Guidelines of April, 1997:

- i) The operating costs of non-regulated activities are not to be reflected in the utility’s cost of service.
- ii) The costs of developing new business ventures are to be charged to and recovered from the NRB.
- iii) The accounting costs are to be transparent and will normally fully recover costs for all services, including overhead, space, employee benefits, inconvenience, and a profit margin where appropriate. If the service provided by the utility to the related-NRB could also be obtained from an independent supplier, the price paid by the related-NRB to the utility should be no less than the competitive market price and will never be below the incremental cost.
- iv) The financial costs of each business are to be borne by the specific business. In the exceptional case where the utility provides guarantees for NRBs, the utility must be given financial compensation.
- v) Utilities will be required to file periodic reports which demonstrate that they are adhering to the transfer pricing policy. The form and timing of the report will be determined by the Commission.



**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** G-???-11

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VANCOUVER, B.C. V6Z 2N3 CANADA
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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Pacific Northern Gas Ltd.
For Approval of its 2012 Revenue Requirements
for the PNG-West Service Area

BEFORE: ??????????, Panel Chair/Commissioner December ??, 2011
????????????????, Commissioner
????????????????, Commissioner

O R D E R

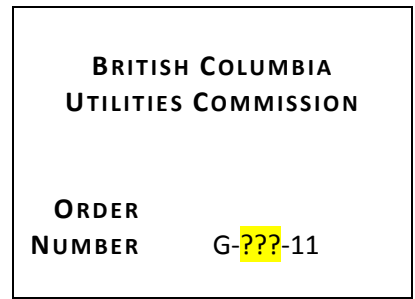
WHEREAS:

- A. Pacific Northern Gas Ltd. (PNG) filed on November 30, 2011 with the British Columbia Utilities Commission (BCUC or Commission), pursuant to sections 58 to 61 of the *Utilities Commission Act* (the Act), its 2012 Revenue Requirements Application (Application) seeking Commission approval to increase its delivery rates;
- B. The Application also seeks refundable interim relief pursuant to section 58 to 61, 89 and 90 of the Act to allow PNG to amend its rates on an interim basis, effective January 1, 2012, pending the hearing of the Application and orders subsequent to that hearing, on the basis that on January 1, 2012 PNG's rates would otherwise no longer be fair, just and not unduly discriminatory;
- C. PNG forecasts a 2012 revenue deficiency of approximately \$0.886 million comprised of a net increase in cost of service of \$1.288 million and an increase in margin of \$0.402 million;
- D. The Application seeks Commission approval to increase the delivery charge for residential service by \$0.358/GJ from \$11.152/GJ to \$11.510/GJ representing an increase of 3.2 percent compared to the 2011 delivery rate, for small commercial service by \$0.282/GJ from \$9.478/GJ to \$9.760/GJ corresponding to an increase of 3.0 percent compared to the 2011 delivery rate, and for Granisle propane service by \$0.231/GJ from \$6.170/GJ to \$6.401/GJ corresponding to an increase of 3.7 percent compared to the 2011 delivery rate;

E. The Commission considers that establishing a Preliminary Regulatory Timetable for the registration of Interveners and for the preliminary review of the Application, and to allow Interveners to make written submissions on a formal review process, is necessary and in the public interest.

NOW THEREFORE pursuant to sections 58 to 61, 89 and 90 of Act the Commission orders as follows:

1. The Commission approves for PNG the delivery rates and the RSAM rider set forth in the Application on an interim basis, effective January 1, 2012. Any differences between the 2012 interim and permanent delivery rates that are determined by the Commission following final disposition of the Application are subject to refund/recovery, with interest at the average prime rate of PNG's principal bank for its most recent year, in the manner as set out by a Commission Order that establishes permanent rates.
2. The Preliminary Regulatory Timetable for the Application is as set out in Appendix A to this Order. The dates and events in Appendix A after January ??, 2012 are subject to further Order establishing the review process and the regulatory timetable for review of the Application.
3. The Commission will hold a Workshop to review the issues in the Application on ?????????? commencing at 9.00 a.m. in the BCUC Office Hearing Room, ?????????? Howe Street, Vancouver, BC.
4. PNG is to provide a copy of this Commission Order, by e-mail where possible, to all parties who participated in the PNG 2011 Revenue Requirements Application proceedings.
5. PNG will publish, as soon as reasonably possible following the issuance of this Order but by no later than ??????????, in display-ad format, the Notice of Application and Workshop as attached as Appendix B to this Order, in such appropriate news publications as may properly provide adequate notice to the public in its service area.
6. PNG will make the Application and supporting materials available for inspection at public libraries in Prince Rupert, Terrace, Kitimat, Houston, Smithers, Burns Lake, Vanderhoof and Fort St. James, and at the Head Office of PNG at Suite 950, 1185 West Georgia Street, Vancouver, B.C., V6E 4E6, and at the British Columbia Utilities Commission, Sixth Floor, 900 Howe Street, Vancouver, B.C., V6Z 2N3. PNG will also make the Application available on PNG's website at <http://www.png.ca>.
7. Interveners and Interested Parties should register with the Commission via E-Mail or in writing, by ??????????, of their intention to intervene. Interveners should specifically state the nature of their interest in the Application, and identify generally the nature of the issues that they intend to pursue during the proceeding and the nature and extent of their anticipated involvement in the Application. The Commission is to receive submissions from Interveners by ?????????? on the appropriate regulatory review process that should be followed in the review of the Application.



8. Interveners intending to apply for participant assistance must submit a budget estimate by January ??, 2012 consistent with the Commission's Participant Assistance/Cost Award Guidelines and Order G-72-07. Copies are available upon request, or can be downloaded from the Commission's website at <http://www.b cuc.com>.
9. The Commission will accept, subject to timely filing by PNG, amended Gas Tariff Rate Schedules in accordance with the terms of this Order. PNG is to provide notice of the interim rates to customers via a bill message, to be reviewed in advance by Commission Staff to confirm compliance with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this day of December, 2011.

BY ORDER
Original signed by:

Commissioner

Attachments

Pacific Northern Gas Ltd.

Application for Approval of 2012 Revenue Requirements
for PNG-West Service Area

PRELIMINARY REGULATORY TIMETABLE

ACTION

DATES

Workshop No. 1

Intervener and Interested Parties Registration

Commission Information Request No. 1

Intervener Information Request No. 1

PNG Responses to Information Requests No. 1

Intervener Comments regarding Regulatory Process

Workshop No. 2 – pending

Announcement of Review Process

NOTICE OF WORKSHOP

Date:	
Time:	9.00 a.m.
Location:	BCUC Office Hearing Room ????? Howe Street, ?? Floor Vancouver, BC



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Pacific Northern Gas Ltd.

Application for Approval of 2012 Revenue Requirements
for PNG-West Service Area

NOTICE OF REVENUE REQUIREMENTS APPLICATION AND WORKSHOP

NOTICE OF WORKSHOP

Date:	
Time:	9.00 a.m.
Location:	BCUC Office Hearing Room ???? Howe Street, ??? Floor Vancouver, BC

THE APPLICATION

Pacific Northern Gas Ltd. (PNG) filed on November 30, 2011 with the British Columbia Utilities Commission (Commission), pursuant to sections 58 to 61, 89 and 90 of the *Utilities Commission Act* (the Act), its 2012 Revenue Requirements Application (Application) to increase delivery rates on an interim and refundable basis effective January 1, 2012 to be made permanent following the Commission's review process.

The Commission wishes to ensure that affected parties have an opportunity to understand the Application and its implications for customer rates. The Commission also wishes to hear from affected parties before determining the public process necessary for the disposition of the Application.

The delivery rate increase is estimated to be approximately \$0.358 per GJ for a residential customer. This represents an increase of 3.2 percent compared to the 2011 delivery rate. The delivery rate increase for a small commercial customer is estimated to be \$0.282 per GJ corresponding to an increase of 3.0 percent compared to the 2011 delivery rate. The Granisle propane delivery rate increase for a residential customer is estimated to be \$0.231 per GJ corresponding to an increase of 3.7 percent compared to the 2011 delivery rate.

Based on the gas cost recovery and GCVA rate riders effective October 1, 2011 the overall average bundled rate increase for a typical residential customer consuming 68.0 GJ per year, is 0.7 percent, an increase of \$9 per year. Similarly, for a small commercial customer consuming 319.7 GJ per year, the increase is 0.4 percent or \$20 per year and for Granisle propane customers consuming 57.6 GJ per year the overall average bundled rate increase is 0.8 percent, an increase of \$13 per year.

THE REGULATORY PROCESSES

The Commission will hold a Workshop on [REDACTED] in Vancouver, BC to discuss issues in the Application.

PUBLIC INSPECTION OF THE APPLICATION

The Application and supporting material will be made available for inspection at public libraries in Prince Rupert, Terrace, Kitimat, Houston, Smithers, Burns Lake, Vanderhoof and Fort St. James, and at the Head Office of PNG at Suite 950, 1185 West Georgia Street, Vancouver, B.C., V6E 4E6, and at the British Columbia Utilities Commission, Sixth Floor, 900 Howe Street, Vancouver, B.C., V6Z 2N3.

The Application will also be available for viewing on the PNG website at www.png.ca, (www.png.ca/ir_utilities.cfm) and on the Commission's website at www.bcuc.com, which also contains detailed materials related to the Application including Commission Orders and Intervener materials (<http://www.bcuc.com/Proceeding.aspx?ApplicationType=Current>).

REGISTERING TO PARTICIPATE

Persons who expect to actively participate in the review process and the Workshop should register as Interveners. Interveners will receive copies of the Application, all correspondence and filed documents. Persons not expecting to actively participate should register with the Commission as Interested Parties and will receive a copy of the Application summary and the Commission's Decision.

Interveners and Interested Parties should inform the Commission Secretary, in writing or by online web registration, by [REDACTED] of their intention to become Interveners or Interested Parties with respect to the Application.

All submissions and/or correspondence received from active participants or the general public relating to the Application will be placed on the public record and posted to the Commission's web site.

FURTHER INFORMATION

For further information, please contact Ms. Alanna Gillis, Acting Commission Secretary, or Mr. Philip Nakoneshny, Director, Rates and Finance, as follows:

Telephone:	(604) 660-4700 or (B.C. Toll Free) 1-800-663-1385
Facsimile:	(604) 660-1102
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