

PACIFIC NORTHERN GAS (N.E.) LTD.

(Tumbler Ridge Division)

2010 Revenue Requirements Applications

to the

B.C. Utilities Commission

October 5, 2009



Pacific Northern Gas (N.E.) Ltd.

(Tumbler Ridge Division)

2010 REVENUE REQUIREMENTS APPLICATION

October 5, 2009

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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 (N.E.) LTD.
(Tumbler Ridge Division)**

2010 REVENUE REQUIREMENTS APPLICATION

October 5, 2009

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

PACIFIC NORTHERN GAS (N.E.) LTD. ("PNG(N.E.)") hereby applies to the British Columbia Utilities Commission (the "Commission") for approval to amend the rate schedules of PNG(N.E.)'s Tumbler Ridge Division in accordance with this Application, effective January 1, 2010. PNG(N.E.) seeks such approval on an interim basis pursuant to sections 58 and 89 of the Utilities Commission Act (the "Act"). The following narrative provides the submissions by PNG(N.E.) in support of the rates applied for in this Application.

INTRODUCTION

PNG(N.E.)'s 2010 revenue requirements Application sets out PNG(N.E.)'s budgeted 2010 costs and forecast revenues using currently approved rates and forecast 2010 gas deliveries. The extent to which forecast revenues vary from forecast costs determines whether PNG(N.E.) is seeking Commission approval of rate increases or decreases for the Tumbler Ridge Division. PNG(N.E.) compares its forecast 2010 costs to the Commission approved negotiated settlement of PNG(N.E.)'s 2009 revenue requirements application ("NSP 2009") to put the 2010 budget figures in context. The forecast 2010 calendar year figures are identified in this Application under the heading "Test Year 2010".

The following regulatory financial schedules are included under Tabs 1 to 5 of 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 Test Year 2010 figures to NSP 2009 figures. A Table is provided on the next page comparing the Test Year 2010 cost of service described in this Application to the NSP 2009 cost of service approved by the Commission.

Test Year 2010 vs. NSP 2009
COST OF SERVICE COMPARISON
(\$000)

EXPENSES	Test Year	NSP	Difference	
	2010	2009	Total	Subtotal
Operating				
Labour	233	233	0	
Other	335	319	16	
Sub-total	<u>568</u>	<u>552</u>	<u>16</u>	
Maintenance				
Labour	26	25	1	
Other	104	69	35	
Sub-total	<u>129</u>	<u>94</u>	<u>36</u>	
Administrative and General				
Labour	0	0	0	
Total Company Benefits	51	44	8	
Other	85	82	3	
Sub-total	<u>136</u>	<u>126</u>	<u>11</u>	
Total (O, M, A & G) Excluding Co. Use	834	771	63	63
Transfers to Capital Operating	(6)	(4)	(2)	
Transfers to Capital Admin. & Gen.	(6)	(4)	(2)	
Property Taxes	80	79	1	
Depreciation	124	116	8	
Amortization	(25)	(37)	12	
Other Income	(12)	(12)	0	
NSP Settlement Allowance for Shared Services	0	(2)	2	18
Total Expenses Excluding Co. Use	<u>988</u>	<u>908</u>	<u>80</u>	<u>80</u>
Income Taxes	20	11	9	
Return on Common Equity	67 ⁽¹⁾	51 ⁽²⁾	16	
Short Term Debt	10	7	3	
Long Term Debt	53	55	(2)	
Preferred Shares	0	0	0	26
Total Cost of Service Excluding Co. Use	<u>1138</u>	<u>1032</u>	<u>106</u>	<u>106</u>
Company Use Gas	79	100		
Total Cost of Service Including Co. Use	<u>1217</u>	<u>1132</u>		
2009 to 2010 Cost of Service Increase (Decrease)			106	
2009 to 2010 Margin Decrease (Increase)			(16)	
2010 Revenue Deficiency (Sufficiency)			<u>90</u>	

1. Deemed common equity of 42.5%
2. Deemed common equity of 36%

The major components of the Test Year 2010 cost of service are summarized below in comparison to the corresponding NSP 2009 figures. The Table shows the main drivers of the projected revenue deficiency in 2010.

Cost of Service Item	\$000's		
	Test Year 2010	NSP 2009	2010/2009 Difference
Operating, Maintenance, Administrative and General Expenses	\$834	\$771	\$63
Transfers to Capital, Operating, Administrative and General	(12)	(8)	(4)
Other Cost of Service items including property taxes and depreciation	166	144	22
Return components including return on equity, income taxes and debt costs	149	124	25
Cost of Service Ex. Co. Use Gas Cost	\$1,138	\$1,032	\$106
Margin Using 2009 Rates	\$1,048	\$1,032	(\$16)
Total Test Year 2010 Revenue Deficiency			\$90
Total Cost of Service Ex. Co. Use Gas	\$1,138	\$1,032	
Company use gas cost pass through	79	100	
Total Cost of Service including Company Use Gas Cost	\$1,217	\$1,132	

The following explains the various components of PNG(N.E.)'s Tumbler Ridge division Test Year 2010 cost of service as summarized above with the overall objective of describing the reasons why the Test Year 2010 cost of service has increased compared to NSP 2009.

OPERATING EXPENSES

Cost Element	\$000's						
	Test Year 2010	NSP 2009	2010/09 Change	Actual 2008	Actual 2007	Actual 2006	Actual 2005
621 – Processing	\$281	\$270	\$11	287	269	263	\$206
665 - Pipelines	13	12	1	8	6	3	2
670 – Supervision	28	29	(1)	22	25	22	19
675 – Mains and Services	6	6	0	6	3	9	9
685 – General Operations	19	19	0	29	27	14	49
688 – Other General Operations	57	53	4	39	46	42	47
711/713/714 Customer Care	41	40	1	36	36	48	43
Add Shared Service Costs	75	71	4	73	65	67	62
Other Including 673 Expenses	48	51	(3)	38	32	23	41
Subtotal	\$568	\$551	\$17	\$539	\$509	\$491	\$478
Transfers to Capital	(\$6)	(\$4)	(\$2)	(\$6)	(\$5)	(\$4)	(\$4)
Operating Expenses Excluding Co. use gas cost	\$562	\$547	\$15	\$533	\$504	\$487	\$474

The above figures exclude the cost of Company use gas as it is treated as a pass through cost since it is dependant on prevailing gas supply market prices. Forecast processing costs under Account 621 are increasing by \$11,000 due to higher outside service costs for completing work on the cooling fan and amine filter systems. Shared service costs are higher in 2010 due to corresponding increases in the PNG-West division.

MAINTENANCE EXPENSES

\$000's							
BCUC Account	Test Year 2010	NSP 2009	2010/2009 Difference	Actual 2008	Actual 2007	Actual 2006	Actual 2005
821 Process Plant	\$116	\$81	\$35	\$122	\$74	\$60	\$37
All Other	13	13	0	8	23	8	3
Total	\$129	\$94	\$35	\$130	\$97	\$68	\$40

The forecast Test Year 2010 maintenance expenses for Account 821 Process Plant are increasing by \$35,000 to reflect the higher contractor costs of maintaining various components of the plant (i.e. amine, glycol and heat system pumps as well as level controls, etc).

ADMINISTRATIVE AND GENERAL EXPENSES

The following provides an historical summary of administrative and general costs.

Cost Element	\$000's						
	Test Year 2010	NSP 2009	2009/08 Change	Actual 2008	Actual 2007	Actual 2006	Actual 2005
721 Administration	\$53	\$49	\$4	\$46	\$46	\$42	\$35
722 Audit Fees	7	9	(2)	5	4	8	3
723 Insurance	11	12	(1)	12	13	14	18
725 Employee Ben.	51	44	7	50	56	60	59
728 General	14	12	3	10	10	10	7
Sub-total	\$136	\$126	\$10	\$124	\$129	\$134	\$122
Less transfers to Capital	(6)	(4)	(2)	(\$6)	(\$5)	(\$5)	(3)
Total	\$130	\$122	\$8	\$118	\$124	\$129	\$119

Administrative and general costs, net of transfers to capital, have increased from \$122,000 under NSP 2009 to \$130,000 in Test Year 2010, an increase of \$8,000. The increase reflects higher administrative shared services charged by PNG (i.e. the parent company of PNG(N.E.)) under Account 721 of \$4,000 and higher costs under Account 728.

SHARED SERVICE CHARGES BY PACIFIC NORTHERN GAS LTD. (“PNG”)

The following Table summarizes the shared service charges allocated by PNG to PNG(N.E.)’s Tumbler Ridge Division over the 2006 to 2010 period. The allocation methodology used in 2010 by PNG to calculate the charges to its wholly owned subsidiary is the same as applied under NSP 2009.

Allocated Costs	\$000’s					
	Test Year 2010	NSP 2009	2010/09 Change	Actual 2008	Actual 2007	Actual 2006
721 Administration Benefits	\$44 9	41 8	\$3 1	38 8	36 9	\$34 6
685 General Ops. Benefits	29 6	28 6	1 0	28 7	23 7	26 7
711/713/714 Customer Care Benefits	32 7	32 6	0 1	30 6	29 7	27 7
728 Corporate	5	5	0	4	4	3
Total Allocated Benefits	111 22	105 21	6 1	101 22	92 23	90 20
Total	\$133	\$126	\$7	\$123	\$115	\$110

Shared service charges by PNG to PNG(N.E.)’s Tumbler Ridge division are projected to increase in 2010 from 2009 levels primarily due to cost increases facing PNG. The reason for the cost increases are provided in the PNG-West 2010 revenue requirements application.

TRANSFERS TO CAPITAL

			(\$000's)			
Cost Element	Test Year 2010	NSP 2009	2010/09 Change	Actual 2008	Actual 2007	Actual 2006
Operating	\$6	\$4	\$2	\$6	\$4	\$4
Administration	\$6	\$4	\$2	\$6	\$5	\$5
% of Overhead Allocated	5.64%	3.92%	1.72%	4.5%	4.5%	4.5%

The allocation of overhead to capital projects for Test Year 2010 has been calculated using a rate of 5.64 percent, compared to 3.92 percent under NSP 2009. The transfer to capital rate is based upon the budgeted component of direct labour in capital projects expected to be completed during the year. PNG(N.E.) is requesting Commission approval to fix the transfer rate for 2010 at 5.64 percent of actual overhead expenses. This figure will be updated when the final 2010 regulatory schedules are filed with the Commission. The increase in the rate reflects an increase in direct capital labour primarily due to a projected addition of 2 new customers in 2010.

PROPERTY TAXES

Cost Element	Test Year 2010	NSP 2009	2010/2009 Difference	Actual 2009	Actual 2008	Actual 2007
Property Taxes	\$59	\$59	\$0	\$57	\$57	\$52
1% in Lieu	21	20	1	20	24	17
Total	\$80	\$79	1	\$77	\$81	\$69

Projected 2010 property taxes reflect assumptions regarding mill rate increases. The 1 percent in lieu tax is based on revenues received by PNG(N.E.) in 2008.

DEPRECIATION

Test Year 2010	NSP 2009	2010/2009 Difference
\$124,000	\$116,000	\$8,000

Depreciation expense is calculated using the applicable fixed percentage rate times the gross plant cost, for each category of plant asset. Depreciation expense is higher in Test Year 2010 primarily due to a higher gross plant in service. Specifically, gross plant is projected to total \$8,843,000 at year end 2010 compared to \$8,591,000 at year end 2009.

AMORTIZATION

Test Year 2010	NSP 2009	2010/2009 Difference
(\$25,000)	(\$37,000)	\$12,000

The amortization expense details are provided under Tab 2. The major changes from NSP 2009 to Test Year 2010 are summarized in the Table below:

Deferral Account	Amortization Expense (\$000's)		
	Test Year 2010	NSP 2009	2010/2009 Difference
Industrial Customer Deliveries	(\$13)	(\$21)	\$8
Property Tax	(1)	2	(3)
Bill 198 Compliance	0	0	0
BCUC Hearing inc. CAP/ROE App	0	0	0
BCUC Fees	2	(3)	5
Short Term Interest	6	1	6
Long Term Interest	0	0	0
Depreciation Adjustment	0	2	(2)
Cost of Service	(\$18)	(18)	0
IFRS	0	0	0
Total	(\$25)	(\$37)	\$12

The Industrial Customer Deliveries deferral account credit balance projected for year end 2009 is a lower credit balance than applied at year end 2008. Hence the lower amortization credit in 2010 based on a two year amortization period over 2010 and 2011. Property taxes in 2009 were lower than budgeted resulting in a credit deferral which is being amortized in 2010. The main reason for the increased amortization of the short term interest deferral account in 2010 compared to under NSP 2009 is higher forecast additions related to standby fees. The higher forecast standby fees are driven by three factors: (i) the higher rate for standby fees under the PNG/PNG(N.E.) operating line following renewal in mid 2010; (ii) the increased size of the operating line; and (iii) a higher proportion of the aggregate standby fees being allocated to Tumbler Ridge as a result of growth in that service area relative to the PNG-West service area.

OTHER INCOME

Test Year 2010	NSP 2009	2010/2009 Difference
\$12,000	\$12,000	0

The other income forecast, representing penalty fees and connection charges recovered from customers, is based on past experience.

INCOME TAXES

Test Year 2010	NSP 2009	2009/2010 Difference
\$20,000	\$11,000	\$9,000

The Test Year 2010 income taxes are higher compared to NSP 2009 primarily due to higher return on common equity and the effective increase in amortization expense. Discussion follows below on the higher assumed deemed common equity and higher risk premium relative to the benchmark utility.

CAPITAL STRUCTURE AND RETURN ON COMMON EQUITY

	Test Year 2010	NSP 2009	2010/2009 Difference
Rate of Return on Equity	9.20%	9.12%	0.08%
Common Equity Thickness	42.5%	36%	6.5%
Common Equity Thickness	\$729,000	\$564,000	\$165,000
Return on Equity	\$67,000	\$51,000	\$16,000

PNG and PNG(N.E.) filed an application with the Commission dated July 16, 2009 entitled “Capital Structure and Equity Risk Premium Application” (the “CAP/ROE Application”). The CAP/ROE Application is seeking Commission approval to increase the PNG(N.E.) equity risk premium relative to the benchmark utility return on equity from 65 to 75 basis points for the Tumbler Ridge division. The increase in the rate of return on equity from 9.12 to 9.20 percent reflects the impact of the 10 basis points increase and using the current Commission approved automatic ROE adjustment formula based on forecast parameters. PNG(N.E.) is also seeking approval under the CAP/ROE Application to increase its deemed common equity thickness for rate making purposes from 36 to 42.5 percent. The forecast cost of service under this Application is based on the 42.5 percent common equity and 75 basis points risk premium PNG(N.E.) has requested to Commission to approve under the CAP/ROE Application. The impact of the potential increase in the benchmark low risk utility return under the Terasen Gas capital structure and return on equity application has not been determined under this Application. PNG(N.E.) is requesting Commission approval of interim rates effective January 1, 2010 based on the parameters set forth in its CAP/ROE Application pending the Commission’s disposition of the CAP/ROE Application.

INTEREST EXPENSE

	Test Year 2010	NSP 2009	2010/2009 Difference
Short-term debt	\$10,000	\$7,000	\$3,000
Long-term debt	\$53,000	\$55,000	(\$2,000)

The Test Year 2010 short term debt interest expense has increased over 2009 due to the increase in the short-term debt component of rate base and a higher projected interest rate. Short term debt is comprised of customer security deposits and operating line draws. Long-term debt interest expense has decreased compared to the NSP 2009 provision due to a

slightly lower embedded interest rates and a lower amount of long term debt due to the higher common equity thickness.

PNG(N.E.) will continue to record changes in interest expense due to differences between forecast and actual floating rates in its interest rate deferral accounts.

COMPANY USE GAS COST

Test Year 2010	NSP 2009	2010/2009 Difference
\$79,000	\$100,000	\$13,000

The volume of Company use gas forecast for Test Year 2010 is slightly higher than the forecast under NSP 2009. However a lower forecast unit cost of gas results in an overall decrease in forecast Company use gas costs.

CAPITAL ADDITIONS

	Test Year 2010	NSP 2009	2010/2009 Difference
Additions including overhead	\$252,000	\$268,000	(\$16,000)
Less overhead	(19,000)	(12,000)	\$1,000
Net	\$233,000	\$256,000	(\$23,000)

All of the planned capital expenditures for Test Year 2010 are related to sustaining safe, secure and reliable operations. The annual gas processing plant turnaround has a forecast cost of \$52,000. Rebuilding the internal workings of the contactor tower is projected to cost \$104,000. Replacing fencing and other minor miscellaneous building modification work will be completed at a forecast cost of \$27,000, while a replacement instrument air compressor will cost \$15,000. Replacement meters will be acquired for \$10,000. A number of minor capital items account for the remainder of the Test Year 2010 budgeted capital expenditures.

EMERGENCY CALLS STATISTICS

Section 10 of the NSP 2009 settlement agreement stated:

“PNG(N.E.) will include in each annual revenue requirements application a summary of the number of emergency calls it made during the current year to the date of the application. The summary shall specify the average response time, the number of calls with a response time greater than 40 minutes and any other information PNG(N.E.) considers would be useful to parties reviewing these statistics.”

These statistics to from January 1, 2009 to September 30, 2009 are provided below:

2009 Emergency Calls Response Statistics

<u>Description</u>	<u>2009 YTD Results</u>	<u>2008 Results (12 months)</u>
Number of emergency calls	11	4
Average response time per call	18 minutes	18 minutes
Number of call with response time over 40 mins.	2	1

2010 FORECAST GAS DELIVERIES

The Test Year 2010 forecast of gas deliveries determines the projected margin PNG(N.E.) will receive from its customers during 2010 to pay the cost of serving those customers. The basis for the 2010 gas requirements forecast is discussed below by customer class.

Residential and Small Commercial Firm Sales Customers

Forecast deliveries to the residential and small commercial customers in 2010 are based on assuming the use per account forecasts that applied under NSP 2009. PNG(N.E.) considers it is reasonable to use the existing use per account figures pending receipt of actual 2009 calendar year gas use statistics. PNG will complete an analysis of the reasonableness of the existing use per account figures in early 2010. PNG files an update to its revenue requirements application early in the test year to primarily show actual results from the previous year. PNG will include a discussion in its update on whether the uses per account or projected numbers of customers need to be revised based on an evaluation of actual gas deliveries and customer counts at year end 2009. The forecast number of customers is based on the average number of customers to the end of August 2009 plus projected additions in 2010.

Large Commercial Sales and Industrial Transportation Service Customers

The following summarizes the projected Test Year 2010 deliveries to the large commercial sales and industrial transportation service customers together with NSP 2009 forecast figures.

GJ's			
Customer Class	Test Year 2010	NSP 2009	Difference
Large Commercial	28,000	24,500	3,500
Industrial T-Service	850,000	850,000	0

The above forecasts for 2010 are based on a review of historical gas deliveries to these customer classes and on discussions with the customers. Under Decision 2007 a gas deliveries deferral account was approved to record the difference between forecast and actual deliveries to the industrial transportation service customer. This deferral account was maintained in 2009. PNG is requesting Commission approval to continue this deferral account in 2010.

RATE MATTERS

Allocation of Revenue Deficiency

PNG(N.E.) has allocated the 2010 revenue deficiency to its customers using the projected 2010 gross margin by customer class as the allocator. This is consistent with the methodology approved by the Commission over the past several years.

Derivation of Forecast Test Year Gas Deliveries and Gross Margin

PNG(N.E.) has included under Tab Rates detailed schedules showing the derivation of the forecast Test Year gas deliveries by applying the forecast use per account to the forecast average number of customers in the case of the residential and small commercial customers. For completeness the forecast deliveries to the other customers is also shown together with the split between sales and transportation service deliveries. This enables one to balance the figures shown on Schedule 1, Tab 1 for sales and transportation service with the corresponding figures shown under Tab Rates. Similarly, the derivation of projected margin recovery in the test year using current rates is shown on schedules included in Tab Rates to verify the figures provided in the summary sheets. There may be some small differences between the detailed schedules and the summary schedules due to rounding that occurs when utilizing large spreadsheets to calculate gross revenue, delivery margin and gas supply costs.

RSAM Rate Rider

The Summary of Proposed Rates Effective January 1, 2010 shows a separate line for the 2010 RSAM rate rider which is based on recovering the estimated year-end 2009 RSAM balance in equal amounts over the 2010 to 2012 three year period. The derivation of the 2010 RSAM rate rider is provided in a Table under Tab Rates. The RSAM rider calculation will be updated to reflect the most recent information available when the final 2010 regulatory schedules are filed with the Commission to set rates effective January 1, 2010. Consequently, the calculated RSAM rider at year end 2009 is indicative only. Therefore, PNG is requesting that the interim rates effective January 1, 2010 reflect the current RSAM rate rider that was made effective January 1, 2009.

2009/2010 Gas Supply Cost Charge Changes/GCVA Riders

The gas supply cost recovery rates shown in the “Summary of Proposed Rates Effective January 1, 2010” are the rates that became effective October 1, 2009. The cost of gas shown at Tab 1, Page 1, Line 16 was calculated using PNG’s gas cost flow through model updated to reflect the 2009/2010 gas supply and price arrangements entered into by PNG with its gas suppliers and to reflect the impact of the forecast gas prices contained in a forward gas price strip dated September 28, 2009.

The 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 to calculate gas supply costs. PNG(N.E.)’s fourth quarter 2009 gas supply cost report to the Commission, to be filed in early December 2009, will contain proposed gas supply cost recovery rates and GCVA rate riders that will differ from the October 1, 2009 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 line 16 of Schedule 1 under Tab 1. The forecast deliveries by customer class times the indicative gas supply prices by customer class generates the cost of sales figure for each customer class.

Determination of 2010 Unit Company Use Gas Cost Rate

The 2010 projected cost of Company use gas is based on forecast gas prices and the quantity of gas PNG(N.E.) expects to purchase for Company use. The calculation of the unit Company use gas cost recovery rate is shown on a schedule under Tab Rates. PNG(N.E.) divides the forecast cost of Company use gas to be supplied by PNG(N.E.) by total deliveries to all customers, except its one transportation service customer, to determine the recovery rate to be embedded in the rates. The figure provided in this Application is indicative only as the current Company use gas delivery rate will be reviewed in the context of PNG(N.E.)’s fourth quarter 2009 gas cost report to the Commission. The transportation service customer supplies their share of Company use gas in kind.

Bill Comparison of Current Rates and January 2010 Rates

PNG includes under Tab Rates a comparison of the projected annual gas bills for residential and small commercial customers using current rates and proposed January 1, 2010 rates. The average uses per account reflected in the calculations are the same as the figures used for forecasting gas deliveries to these customer classes in 2010.

The average rate increase for residential customers is estimated to be 7.8 percent on the delivery charge component of rates or \$37 per year for an average customer. This assumes a bundled average rate of \$8.877/GJ which is \$12.003/GJ lower than the electricity equivalent rate of \$20.88/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 7.8 percent on the delivery charge component of rates or \$209 per year for an average customer. This assumes a bundled average rate of \$7.243/GJ which is \$12.177/GJ lower than the electricity equivalent rate of \$19.42/GJ assuming a 90 percent gas to electricity efficiency factor.

Demand Side Management

Section 6 of the NSP 2009 settlement agreement stated the following with respect to Demand Side Management:

“Resolution:

It was acknowledged by the parties that PNG(N.E.)’s relatively small customer base made it difficult to be at the forefront of implementing DSM programs in its service area. However, PNG(N.E.) will continue to actively participate in provincial government and industry working groups that are focusing on what DSM programs to implement throughout the province. PNG(N.E.) has been attending a number of workshops and other forums to ensure PNG(N.E.) is well aware of the ambit of DSM programs potentially usable by PNG(N.E.). In this way, PNG(N.E.) is hopeful it will identify DSM programs that can be successfully implemented by a relatively small utility at reasonable cost.” PNG(N.E.) will focus its efforts on targeting DSM programs that can help its lower income customers to reduce their energy use and costs. This is in recognition of the unique circumstances faced by customers that may not be able to afford to purchase higher efficiency natural gas appliances but at the same time may have the greatest need to reduce their energy use to achieve corresponding cost savings.”

PNG(N.E.) will continue in 2010 to address DSM in accordance with the undertaking set out under the NSP 2009 settlement agreement.

Commission Orders Sought by PNG(N.E.)

PNG(N.E.) is seeking the following Commission approvals under this Application:

1. Approval, effective January 1, 2010, on an interim basis pursuant to sections 58 and 89 of the B.C. Utilities Commission Act (the “Act”), of the delivery charges set forth under the heading “Proposed Rates January 1, 2010” as set forth in the table under Tab Rates entitled “Summary of Proposed Rates Effective January 1, 2010” on the understanding that the permanent delivery rates will be approved by the Commission following the Commission’s disposition of PNG’s CAP/ROE Application in 2010.
2. Approval of a an overhead capitalization rate of 5.64 percent, subject to modification upon filing of the final 2010 revenue requirements application regulatory schedules.
3. Approval of the deferral accounts and amortization expenses for 2010 as set forth in under Tab 2, pages 8 and 9.
4. Approval to continue the unaccounted for gas volume deferral account to record the difference between forecast and actual unaccounted for gas (“UAF”) volumes in Test Year 2010 based on using a 0 percent of deliveries UAF loss factor for 2010 and requiring PNG(N.E.) to apply for Commission approval to record actual 2010 UAF losses above 1.0 percent in the deferral account.

Draft Commission Order

A draft Commission order is set out under Tab 6. The Order addresses PNG(N.E.)'s request for approval of interim rates effective January 1, 2010 and sets out a proposed preliminary regulatory timetable. PNG(N.E.) is recommending that this Application be settled under a negotiated settlement process on the understanding that rates will remain interim pending the Commission's disposition of the CAP/ROE Application. In other words, the negotiated settlement would address all of the issues other than those to be addressed under the CAP/ROE Application. Following the release of the Commission's decision on the CAP/ROE Application, PNG(N.E.) would file updated regulatory schedules and make a submission to the Commission regarding what adjustments would need to be made to the interim rates to reflect the Commission's decision. Permanent rates effective January 1, 2010 would then be set and billing adjustments would be made in the ordinary course.

All of which is respectfully submitted

DATED at Vancouver, British Columbia this 5th day of October 2009.

PACIFIC NORTHERN GAS (N.E.) 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 (N.E.) Ltd.
(Tumbler Ridge Division)

Summary of Proposed Rates Effective January 1, 2010
(\$/GJ unless otherwise specified)

Customer Class	Rates Effective October 1, 2009	Proposed 2010 Revenue Requirement	Proposed Rates January 1, 2010	Rate Changes
<u>Residential (RS1)</u>				
Monthly Fixed Charge	\$8.50		\$8.50	-
Delivery Charge	3.996	0.454	4.450	0.454
Company Use	0.477		0.477	-
GCV A Co. Use Rider	(0.041)		(0.041)	-
RSAM	(0.034)		(0.034)	-
Subtotal Delivery	4.398	0.454	4.852	0.454
Gas Supply Commodity	4.244		4.244	-
GCV A Commodity Rider	(2.156)		(2.156)	-
Subtotal Commodity	2.088	0.000	2.088	-
Total	6.486	0.454	6.940	0.454
<u>Small Commercial (RS2)</u>				
Monthly Fixed Charge	\$8.50		\$8.50	-
Delivery Charge	3.535	0.333	3.868	0.333
Company Use	0.477		0.477	-
GCV A Co. Use Rider	(0.041)		(0.041)	-
RSAM	(0.034)		(0.034)	-
Subtotal Delivery	3.937	0.333	4.270	0.333
Gas Supply Commodity	4.244		4.244	-
GCV A Commodity Rider	(2.156)		(2.156)	-
Subtotal Commodity	2.088	0.000	2.088	-
Total	6.025	0.333	6.358	0.333
<u>Large Commercial (RS3)</u>				
Monthly Fixed Charge	\$8.50		\$8.50	-
Delivery Charge	2.966	0.275	3.241	0.275
Company Use	0.477		0.477	-
GCV A Co. Use Rider	(0.041)		(0.041)	-
Subtotal Delivery	3.402	0.275	3.677	0.275
Gas Supply Commodity	4.244		4.244	-
GCV A Commodity Rider	(2.156)		(2.156)	-
Subtotal Commodity	2.088	0.000	2.088	-
Total	5.490	0.275	5.765	0.275
<u>Industrial Transport (CNRL)</u>				
Monthly Fixed Charge	\$10,000.00		\$10,000.00	-
Delivery Charge	0.214	0.028	0.242	0.028

**Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)**

**Bill Comparison
October 2009 to January 2010**

Customer Classification	Annual Use	Permanent Rates	Annual Bill	Proposed Rates	Annual Bill	Annual Bill	
		Oct. 1, 2009 \$ / GJ	Estimate \$	Jan. 1, 2010 \$ / GJ	Estimate \$	\$	%
Residential:	84.5 GJ						
Monthly Fixed Charge @ 8.50 / mo.		1.207	102.00	1.207	102.00	0.00	
Delivery Charge		4.473	377.97	4.912	415.09	37.12	
GCVA Co. Use Rider		(0.041)	(3.46)	(0.041)	(3.46)	0.00	
RSAM Rider		(0.034)	(2.87)	(0.034)	(2.87)	0.00	
			473.63		510.76	37.13	7.8%
Gas Supply Charge		4.244	358.62	4.244	358.62	0.00	
GCVA Rider		(2.156)	(182.18)	(2.156)	(182.18)	0.00	
			176.44		176.44	0.00	0.0%
Carbon Tax		0.745	62.95	0.745	62.95	(0.00)	
		\$8.438 /GJ	\$713.02	\$8.877 /GJ	\$750.15	37.13	5.2%
Permanent Rates Effective Jan. 1, 2009 compared to Proposed Rates Jan. 1, 2010							
		\$11.399 /GJ	\$963.22	\$8.877 /GJ	\$750.15	-\$213.07	-22.1%
Small Commercial:	656.5 GJ						
Monthly Fixed Charge @ 8.50 / mo.		0.155	102.00	0.155	102.00	0.00	
Delivery Charge		4.012	2,633.88	4.330	2,842.62	208.74	
GCVA Co. Use Rider		(0.041)	(26.92)	(0.041)	(26.92)	0.00	
RSAM Rider		(0.034)	(22.32)	(0.034)	(22.32)	0.00	
			2,686.64		2,895.38	208.74	7.8%
Gas Supply Charge		4.244	2,786.19	4.244	2,786.19	0.00	
GCVA Rider		(2.156)	(1,415.41)	(2.156)	(1,415.41)	0.00	
			1,370.77		1,370.77	0.00	0.0%
Carbon Tax		0.745	489.09	0.745	489.09		
		\$6.925 /GJ	\$4,546.51	\$7.243 /GJ	\$4,755.25	\$208.74	4.6%
Permanent Rates Effective Jan. 1, 2009 compared to Proposed Rates Jan. 1, 2010							
		\$9.886 /GJ	\$6,490.16	\$7.243 /GJ	\$4,755.25	-\$1,734.91	-26.7%

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

SUMMARY OF PROPOSED GAS DELIVERY CHARGE RATE CHANGES
EFFECTIVE JANUARY 1, 2010

Customer Classification	2010 Test Year Gas Deliveries (GJ)	2010 Gross Margin (\$)	Allocation of Revenue Deficiency (\$)	Rate Changes for Revenue Deficiency (\$/GJ)
Residential Sales (RS1)	90,995	515,489	41,336	0.454
Small Commercial Sales (RS2)	51 290	212,969	17,078	0.333
Large Commercial Sales (RS3)	28 000	96,189	7,713	0.275
Total Sales	170 285	824,647	66,127	
Industrial Transport (CNRL)	850 000	301,900	24,209	0.028
TOTAL	1 020 285	1,126,547	90,336	

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

SUMMARY OF REVENUE, COST OF GAS, GROSS MARGIN

Customer Classification	2010 Test Year			
	Gas Deliveries (GJ)	Revenue (\$)	Cost of Gas (\$)	Gross Margin (\$)
Residential Sales (RS1)	90,995	962,444	446,955	515,489
Small Commercial Sales (RS2)	51,290	464,901	251,932	212,969
Large Commercial Sales (RS3)	28,000	233,725	137,536	96,189
Industrial Transport (CNRL)	850,000	301,900	0	301,900
Total	1 020 285	1,962,970	836,423	1,126,547

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Derivation of Test Year Forecast Gas Deliveries

Customer Classification	Forecast Customer Count At Dec. 31st, 2009	+	Test Year Effective Customer Additions	=	Test Year Weighted Average Customer Count	x	Test Year Average Use Per Account (GJ)	=	2010 Test Year Deliveries (GJ)
Sales:									
Residential (Rate 1)	1,076		1		1,077		84.5		90,995
Commercial									
Small Commercial (Rate 2)	78		0		78		656.5		51,290
Large Commercial Firm (Rate 3)									28,000
Total Commercial									
Subtotal Sales									170,285
									2010 Test Year Deliveries (GJ)
Transport									
CNRL									850,000
Total									1,020,285

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Derivation of Test Year Forecast Gross Margin

Customer Classification	2010 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	Test Year Gross Margin
Sales:								
Residential (Rate 1)	90,995	4.458	405,656	1,077	8.50	109,846	515,501	515,501
Commercial								
Small Commercial (Rate 2)	51,290	3.997	205,006	78	8.50	7,889	212,895	212,895
Large Commercial (Rate 3)	28,000	3.428	95,984	3	8.50	306	96,290	96,290
Total Commercial	79,290		300,990	81		8,195	309,185	309,185
Subtotal Sales	170,285		706,646			118,041	824,686	824,686
Transportation:								
CNRL	850,000	0.214	181,900	1	10,000	120,000	301,900	301,900
Subtotal Transportation	850,000		181,900			120,000	301,900	301,900
TOTAL	1,020,285		888,546			238,041	1,126,586	1,126,586

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Derivation of Test Year Forecast Gas Supply Cost

Customer Classification	2010 Test Year Deliveries (GJ)	Gas Cost Charge (\$ / GJ)	Total Gas Cost (\$)
Residential (Rate 1)	90,995	4.912	446,967
Commercial			
Small Commercial (Rate 2)	51,290	4.912	251,936
Large Commercial (Rate 3)	28,000	4.912	137,536
Total Commercial	79,290		389,472
Total Tumbler Ridge	170,285		836,440

**Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)**

DETERMINATION OF GAS SUPPLY COST RATE CHANGES EFFECTIVE JANUARY 1, 2010

Using September 28, 2009 Forward Gas Strip

Customer Classification	Gas Supply Costs Rates Rates Effective October 1, 2009		Gas Supply Costs Proposed Rates Indicative Rates Effective January 1, 2010		Indicative Gas Supply Cost Rate Changes Effective January 1, 2010	
	Commodity	Company Use Gas	Commodity ⁽¹⁾	Company Use Gas ⁽²⁾	Gas Supply Commodity	Company Use Gas
	(\$/GJ)	(\$/GJ)	(\$/GJ)	(\$/GJ)	(\$/GJ)	(\$/GJ)
Residential (RS1)	4.244	0.477	4.912	0.462	0.668	(0.015)
Small Commercial (RS2)	4.244	0.477	4.912	0.462	0.668	(0.015)
Large Commercial (RS3)	4.244	0.477	4.912	0.462	0.668	(0.015)
Industrial Sales (RS4)	4.244	0.477	4.912	0.462	0.668	(0.015)

Notes:

1.The commodity charges are payable for each GJ of gas purchased by PNG(N.E.). The commodity charges represent PNG(N.E.)'s projection of its commodity costs based on its projected gas supply purchases.

2.The unit company use gas cost is determined by dividing the projected cost of company use gas by gas sales.

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

Determination of Indicative 2010 Unit Company Use Gas Cost Rate

Using September 28, 2009 Forward Gas Strip	
Demand Cost	\$0
Commodity Cost	\$64,617
B.C.S.S. Tax	\$2,793
Ice Levy	\$160
Carbon Tax	<u>\$11,049</u>
Total Company Use Gas Cost	<u><u>\$78,619</u></u>
Total Company use gas requirement	13 155 GJ
Deliveries	170 285 GJ
2009 Unit Company Use Gas Cost Rate	
\$0.462 /GJ	\$78,619
	170 285
Commodity Cost of Company Use Gas per GJ Purchased	
\$4.912 /GJ	\$64,617
	13 155

**Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)**

Determination of Indicative 2010 Revenue Stabilization Adjustment Mechanism (RSAM) Rider

	Residential	Small Commercial	Total
Actual RSAM Balance at Year-end 2008	\$61,268	(78,365)	(\$17,097)
Estimated RSAM Recovery / Deferral in 2009	\$3,378	(3,962)	(\$584)
Estimated RSAM Balance at Year-end 2009	\$64,646	(\$82,327)	(\$17,681)
Years of Amortization			3
RSAM Balance divided by 3 Equals Amortization			(\$5,894)
Forecast 2010 Deliveries	90,992	51,289	142,281
One Year of Amortization divided by 2010 Deliveries equals RSAM Rate Rider (\$/GJ)			(0.041)

Pacific Northern Gas (N.E.) Ltd.

**Forward Gas Price Strip
September 28, 2009**

	STATION #2 CDN\$/GJ	AECO CDN\$/GJ
Jan-10	5.6848	5.5448
Feb-10	5.7199	5.5799
Mar-10	5.6728	5.5329
Apr-10	5.2027	5.2927
May-10	5.2440	5.3340
Jun-10	5.3192	5.4092
Jul-10	5.4088	5.4988
Aug-10	5.4892	5.5792
Sep-10	5.5614	5.6514
Oct-10	5.7232	5.8132
Nov-10	6.2468	6.1718
Dec-10	6.6024	6.5274
Average	5.6563	5.6613

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

UTILITY INCOME & RETURN

SCHEDULE 1
(000's)

Line No.		Test Year 2010	NSP 2009
1	Energy sales (TJ)	170	165
2	Average rate per GJ	\$10.14	\$11.75
3			
4	Transportation service (TJ)	850	850
5	Average rate per GJ	\$0.38	\$0.36
6			
7	Total deliveries (TJ)	1 020	1 015
8			
9	Utility revenue		
10	Energy sales	\$1,661	\$1,950
11	Interim rates - sales	66	(7)
12	Transportation service	302	304
13	Interim rates - transportation	24	(3)
14			
15		2,053	2,245
16	Cost of sales	836	1,113
17			
18	Gross margin	1,217	1,132
19			
20	Operating expenses	640	647
21	Maintenance expenses	129	94
22	Admin. & general expenses	131	122
23	Property taxes	80	79
24	Depreciation	124	116
25	Amortization	(25)	(37)
26	Investment income, other revenue	(12)	(12)
27	NSP Settlement Allowance for Shared Services	0	(2)
28		1,067	1,008
29			
30	Earned return before income taxes	150	124
31	Income taxes	20	11
32			
33	Earned return	\$130	\$113
34			
35	Utility rate base	\$1,715	\$1,565
36			
37	Return on rate base	7.58%	7.21%

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

SUMMARY OF OPERATING, MAINTENANCE
& ADMINISTRATIVE & GENERAL EXPENSES

(000's)

Line No.	Account and Description	Test Year 2010	NSP 2009
1	OPERATING EXPENSES		
2	- wages	233	233
3	- gas	79	100
4	- transferred to capital	(6)	(4)
5	- other	335	319
6	Total Operating	640	647
7	MAINTENANCE EXPENSES		
8	- wages	26	25
9	- other	104	69
10	Total Maintenance	129	94
11	ADMINISTRATIVE AND GENERAL EXPENSES		
12	- wages	0	0
13	- benefits	51	44
14	- transferred to capital	(6)	(4)
15	- other	85	82
16	Total Admin & General	131	122
17	TOTAL EXPENSES	\$900	\$863
	Net of Transfers & Gas	834	771

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

OPERATING EXPENSES

(000's)

Line No.	Account and Description	Test Year 2010	NSP 2009
1	621 Processing	281	270
2	Process plant - gas	79	100
		359	370
3	664 Communications	2	2
4	665 Pipelines	13	12
5	Pipelines - Gas	0	0
6	667 Regulating Stations	11	11
7	Total transmission	26	24
8	670 Supervision	28	29
9	673 Removing & resetting meters	18	22
10	674 Service on customer premises	2	2
11	675 Mains and services	6	6
12	677 Regulating stations	0	0
13	679 Other	0	0
		0	0
14	Total distribution	53	59
15	684 Communications	0	0
16	685 General systems operations	19	19
17	Shared Services from Parent	36	34
18	688 Other general operations	57	53
19	689 Transferred to capital	(6)	(4)
		(6)	(4)
20	Total general	105	102
21	701 Advertising	0	1
22	702 Demonstration and selling	1	1
23	709 Other	0	0
		0	0
24	Total sales	1	2
25	710 Customer Accounting	1	0
26	711 Customer contracts	0	0
27	Shared Services from Parent	13	10
28	712 Meter reading	10	12
29	713 Customer billing	37	36
30	Shared Services from Parent	21	22
31	714 Credit and collections	4	4
32	Shared Services from Parent	5	5
33	718 Uncollectible accounts	4	1
		4	1
34	Total customer accounting	95	91
35	Total operating	\$640	\$647

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

MAINTENANCE EXPENSES

(000's)

Line No.	Account and Description	Test Year 2010	NSP 2009
1	821 Process plant	116	81
2	864 Communications	0	0
3	865 Pipe lines	1	1
4	866 Compressors	0	0
5	867 Regulating stations	2	2
6	Total transmission	3	3
7	872 Structures	5	5
8	874 Customer premises	0	0
9	875 Mains and services	1	1
10	877 Regulating stations	0	0
11	878 Meters	2	2
12	879 Other	0	0
13	Total distribution	8	8
14	884 Communications	2	2
15	885 General	1	1
16	Total general	2	2
17	Total maintenance	\$129	\$94

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

ADMINISTRATIVE AND GENERAL EXPENSES

(000's)

Line No.	Account and Description	Test Year 2010	NSP 2009
1	721 Administration Shared Services from Parent	0 53	0 49
2	722 Audit fees	7	9
3	723 Insurance	11	12
4	724 Reserve for damages	0	0
5	725 Employee benefits	51	44
6	728 Shared Services from Parent	5	5
7	Regulation	9	6
8	Donations	1	1
9	729 Transferred to capital	(6)	(4)
10	Total administrative and general	<u>\$131</u>	<u>\$122</u>

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

TAXES OTHER THAN INCOME TAXES

(000's)

Line No.	Account and Description	Test Year 2010	NSP 2009
1	PROPERTY TAXES		
2	Regular	\$59	\$59
3	Other 1% in lieu	21	20
4	TOTAL	<u>\$80</u>	<u>\$79</u>

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

MISCELLANEOUS OPERATING REVENUE

(000's)

Line No.	Description	Test Year 2010	NSP 2009
1	Penalty charges	\$7	\$7
2	Connection Fees	\$2	2
3	Rents	0	0
4	Overheads recovered	1	1
5	Automotive surcharges	0	0
6	Other	1	1
7		<u>\$12</u>	<u>\$12</u>

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

UTILITY RATE BASE

SCHEDULE 2
(000's)

Line No.		Test Year 2010	NSP 2009
1	Plant in service beginning of year	\$8,591	\$8,323
2	Additions	252	268
3	Disposals	-	-
4			
5	Plant in service end of year	8,843	8,591
6	Accumulated depreciation	5,574	5,403
7			
8	Net plant in service end of year	3,269	3,189
9			
10	Net plant beginning of year	3,192	3,085
11			
12	Net plant in service midyear	3,231	3,137
13	Contributions for construction	(1,050)	(1,093)
14	Unamortized deferred charges	(25)	(36)
15	Deferred income taxes	(415)	(415)
16	Reserve for damages	(155)	(155)
17	Cash working capital	129	127
18	Other working capital	-	-
19			
20	Utility rate base, midyear	\$1,715	\$1,565

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

GAS PLANT IN SERVICE
2009
(\$ 000's)

Line	Description	Actual					Forecast '09 Ending Balance
		Actual Jan/09 Beginning Balance	Additions	Allocations	Transfers	Retirements	
1	Processing plant						
2	410 Land	3					3
3	411 Land Rights						
4	412 Compressor Structures	34					34
5	413 Regulating Structures	75					75
6	417 Regulating Equipment	30					30
7	418 Purification Equipment	3,079	117	11			3,207
8							
9		3,222	117	11			3,349
10	Transmission plant						
11	460 Land						
12	461 Land rights						
13	462 Compressor structures						
14	463 Regulating structures						
15	465 Mains	1,716					1,716
16	466 Compressor equipment	4					4
17	467 Regulating equipment	105					105
18	468 Communications						
19	469 Other						
20		1,825					1,825
21	Distribution plant						
22	471 Land rights	2					2
23	472 Structures	206	7	1			214
24	473 Services	583	5				588
25	474 House installations	262					262
26	475 Mains	984					984
27	476 Compressor equipment						
28	477 Regulating equipment	194	56				250
29	478 Meters	239	10				249
30	479 Other						
31		2,470	79	1			2,550
32	General plant						
33	480 Land	23					23
34	481 Land rights						
35	482 Structures	402					402
36	483 Office equipment	31					31
37	484 Transportation equipment	82					82
38	485 Heavy work equipment	37	56				93
39	486 Tools	87	4				91
40	487 Computer equipment	27	1				28
41	488 Communications	117					117
42	489 Other						
43		806	61				867
44	Construction overheads						
45	Unallocated construction costs		4	(4)			
46	System operations transfers		4	(4)			
47	Administrative transfers		4	(4)			
48	Depreciation						
49			12	(12)			
50		8,323	268				8,591

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

GAS PLANT IN SERVICE
2010
(\$ 000's)

Line	Description	Forecast				Forecast '10 Ending Balance
		Forecast Jan/10 Beginning Balance	Additions	Allocations	Retirements	
1	Processing plant					
2	410 Land	3				3
3	411 Land Rights	3				3
4	412 Compressor Structures	34				34
5	413 Regulating Structures	75				75
6	417 Regulating Equipment	30				30
7	418 Purification Equipment	3,207	166	16		3,388
8						
9		3,349	166	16		3,531
10	Transmission plant					
11	460 Land					
12	461 Land rights					
13	462 Compressor structures					
14	463 Regulating structures					
15	465 Mains	1,716				1,716
16	466 Compressor equipment	4				4
17	467 Regulating equipment	105				105
18	468 Communications					
19	469 Other					
20		1,825				1,825
21	Distribution plant					
22	471 Land rights	2				2
23	472 Structures	214	27	3		243
24	473 Services	588	8	1		597
25	474 House installations	262				262
26	475 Mains	984				984
27	476 Compressor equipment					
28	477 Regulating equipment	250				250
29	478 Meters	249				260
30	479 Other					
31		2,550	45	3		2,598
32	General plant					
33	480 Land	23				23
34	481 Land rights					
35	482 Structures	402				402
36	483 Office equipment	31	8			39
37	484 Transportation equipment	82				82
38	485 Heavy work equipment	93	4			97
39	486 Tools	91	10			101
40	487 Computer equipment	28				28
41	488 Communications	117				117
42	489 Other					
43		867	22			889
44	Construction overheads					
45	Unallocated construction costs					
46	System operations transfers		6	(6)		
47	Administrative transfers		6	(6)		
48	Depreciation		7	(7)		
49			19	(19)		
50		8,591	252	(0)		8,843

Pacific Northern Gas (NE) Ltd.
Tumbler Ridge

GAS PLANT IN SERVICE - CONTINUITY OF PLANT COST

(000's)

<u>Line</u>	<u>Description</u>	Test Year <u>2010</u>	Forecast <u>2009</u>
1	Balance, Beginning of Year	8,591	8,323
2	CIAC Balance, Beginning of Year	(4,246)	(4,245)
3	Plant Cost, net of CIAC, Beginning of Year	<u>4,345</u>	<u>4,078</u>
4	Additions during year:		
5	Plant Cost	233	256
6	Allocation of overheads	19	12
7	Total Plant Additions	<u>252</u>	<u>268</u>
8	Contributions in Aid of Construction	<u>(57)</u>	<u>(1)</u>
9	Total Additions	<u>195</u>	<u>267</u>
10	Plant Retirements:		
11	Normal Course		
12	Deactivated Assets		
13	CIAC Retirements		
14	Total Retirements	<u> </u>	<u> </u>
15	Balance, End of Year	<u>4,540</u>	<u>4,345</u>
16	Closing balance consists of:		
17	Plant Cost	8,843	8,591
18	CIAC	<u>(4,303)</u>	<u>(4,246)</u>
19	Balance, End of Year	<u>4,540</u>	<u>4,345</u>

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)
CONTINUITY OF
ACCUMULATED DEPRECIATION

FOR THE YEAR 2009

(\$ 000's)

Line	Description		Forecast					Forecast '09 Ending Balance
			Actual Jan/09 Beginning Balance	Provision	Transfers	Retirements	Recoveries	
1	Gathering plant							
2	412 Compressor Structures	3.00%	(10)	(1)				(11)
3	413 Regulating Structures	3.00%	(47)	(2)				(50)
4	417 Regulating Equipment	3.00%	(7)	(1)				(8)
5	418 Purification Equipment	5.00%	(2,502)	(42)				(2,543)
6								
7			(2,566)	(46)				(2,612)
8	Transmission plant							
9	462 Compressor structures	3.00%						
10	463 Regulating structures	3.00%						
11	465 Mains	2.00%	(846)	(34)				(880)
12	466 Compressor equipment	3.00%	(2)	0				(2)
13	467 Regulating equipment	3.00%	(24)	(3)				(28)
14	468 Communications	5.00%						
13	469 Other	3.00%						
14								
15			(872)	(38)				(909)
16	Distribution plant							
17	472 Structures	3.00%	(23)	(6)				(30)
18	473 Services	2.00%	(221)	(12)				(233)
19	474 House installations	3.00%	(177)	(8)				(185)
20	475 Mains	2.00%	(425)	(20)				(445)
21	476 Compressor equipment	0.00%						
22	477 Regulating equipment	3.00%	(156)	(6)				(161)
23	478 Meters	3.00%	(151)	(7)				(158)
24	479 Other	3.00%						
25								
26			(1,153)	(58)				(1,211)
27								
28	General plant							
29	482 Structures	3.00%	(338)	(12)				(350)
30	483 Office equipment	5.00%	(14)	(1)				(16)
31	484 Transportation equipment	15.00%	(78)					(78)
32	485 Heavy work equipment	5.00%	(31)	(2)				(32)
33	486 Tools	5.00%	(46)	(3)				(49)
34	487 Computer equipment	20.00%	(27)					(27)
35	488 Communications	5.00%	(114)	0				(114)
36	489 Other	5.00%						
37			(648)	(19)				(667)
38								
39			(5,239)	(160)				(5,399)
40	Amortization of Contributions							
41	Processing		2,322					2,322
42	Transmission		698	33				731
43	Distribution		138	11				149
44	General		1					1
45	Total Amortization of Contributions		3,159	44				3,203
46	Accum Depn/Amort (incl contrib)		(2,080)					(2,196)
47	Amortization of CIAC				44			
48	Depreciation capitalized (see calc below)				3			
49	Net depreciation expense				(113)			

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)
CONTINUITY OF
ACCUMULATED DEPRECIATION

FOR THE YEAR 2010

(\$ 000's)

Line	Description		Forecast			Forecast '10 Ending Balance
			Forecast Jan/10 Beginning Balance	Provision	Retirements	
1	Gathering plant					
2	412 Compressor Structures	3.00%	(11)	(1)		(12)
3	413 Regulating Structures	3.00%	(50)	(2)		(52)
4	417 Regulating Equipment	3.00%	(8)	(1)		(9)
5	418 Purification Equipment	5.00%	(2,543)	(47)		(2,590)
6						
7			(2,612)	(51)		(2,663)
8	Transmission plant					
9	462 Compressor structures	3.00%				
10	463 Regulating structures	3.00%				
11	465 Mains	2.00%	(880)	(34)		(914)
12	466 Compressor equipment	3.00%	(2)	(0)		(2)
13	467 Regulating equipment	3.00%	(28)	(3)		(31)
14	468 Communications	5.00%				
13	469 Other	3.00%				
14						
15			(909)	(38)		(947)
16	Distribution plant					
17	472 Structures	3.00%	(30)	(6)		(36)
18	473 Services	2.00%	(233)	(12)		(245)
19	474 House installations	3.00%	(185)	(8)		(193)
20	475 Mains	2.00%	(445)	(20)		(465)
21	476 Compressor equipment	0.00%				
22	477 Regulating equipment	3.00%	(161)	(8)		(169)
23	478 Meters	3.00%	(158)	(7)		(165)
24	479 Other	3.00%				
25						
26			(1,211)	(61)		(1,272)
27						
28	General plant					
29	482 Structures	3.00%	(350)	(12)		(362)
30	483 Office equipment	5.00%	(16)	(1)		(17)
31	484 Transportation equipment	15.00%	(78)	(4)		(82)
32	485 Heavy work equipment	5.00%	(32)	(5)		(37)
33	486 Tools	5.00%	(49)	(3)		(53)
34	487 Computer equipment	20.00%	(27)			(27)
35	488 Communications	5.00%	(114)	(0)		(115)
36	489 Other	5.00%				
37			(667)	(25)		(692)
38						
39			(5,399)	(175)		(5,574)
40	Amortization of Contributions					
41	Processing		2,322	(0)		2,322
42	Transmission		731	33		765
43	Distribution		149	10		159
44	General		1			1
45	Total Amortization of Contributions		3,203	44		3,247
46	Accum Depn/Amort (incl contrib)		(2,196)			(2,327)
47	Amortization of CIAC			44		
48	Depreciation capitalized			7		
49	Net depreciation expense			(124)		

Pacific Northern Gas (NE) Ltd.
Tumbler Ridge

GAS PLANT IN SERVICE - CONTINUITY OF ACCUMULATED DEPRECIATION

(000's)

<u>Line</u>	<u>Description</u>	<u>Test Year 2010</u>	<u>Forecast 2009</u>
1	Balance, Beginning of Year	(5 399)	(5 239)
2	CIAC Accumulated Balance, Beginning of Year	3 203	3 159
3	Utility Accumulated Depreciation, Beginning of Year	(2 196)	(2 080)
4	Depreciation Provision:		
5	Plant	(175)	(160)
6	Contributions in Aid of Construction	44	44
7	Depreciation Adjustment Deferral		
8	Total Additions	(131)	(116)
9	Plant Retirements:		
10	Normal Course		
11	Deactivated Assets		
12	CIAC Retirements		
13	Removal Costs		
14	Proceeds on Disposals		
15	Total Retirements		
16	Balance, End of Year	(2 327)	(2 196)
17	Closing Balance Consists of:		
18	Accumulated Depreciation - Plant	(5 574)	(5 399)
19	Accumulated Amortization - CIAC	3 247	3 203
20	Balance, End of Year	(2 327)	(2 196)

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CONTINUITY OF DEFERRED CHARGES

		YEAR 2009				
		(000's)				
Line	Description	<u>Actual</u> <u>Balance '08</u>	<u>Gross</u> <u>Additions</u>	<u>Tax</u>	<u>Amortization</u>	<u>Actual</u> <u>Balance '09</u>
1	Rate base items					
2	Studies	3	0	0	0	3
3	Line Repair (Babcock)	0	0	0	0	0
3	Industrial Deliveries	(41)	(8)	3	(21)	(27)
4	BCUC Hearing & CAP/ROE	(0)	1	(0)	0	0
5	Property tax deferral	2	(2)	1	2	(1)
6	Resource Plan	1	0	0	0	1
7	RSAM	(12)	(1)	0	0	(12)
8	Tumbler Ridge Plant Upset	0	0	0	0	0
9	Bill 198 Compliance Costs	1	0	0	0	0
10	IFRS	0	1	(0)	0	1
11		<u>(47)</u>	<u>(9)</u>	<u>3</u>	<u>(19)</u>	<u>(35)</u>
12	Average rate base for the year					<u><u>(\$41)</u></u>
13	Interest bearing deferrals					
14	BCUC Fees	(0)	(2)	1	(3)	2
15	GCVA	(167)	(110)	32	0	(245)
16	Depreciation Adjustment	2	0	0	2	(0)
17	Short term Interest	0	2	(1)	1	1
18	Long term Interest	(1)	0	(0)	(0)	(0)
19	Carbon / Income Tax	(0)	0	0	(0)	0
20	Cost of Service	(36)	0	0	(18)	(18)
21		<u>(203)</u>	<u>(109)</u>	<u>32</u>	<u>(19)</u>	<u>(261)</u>
22						
23	Total deferrals (excl. Debt Issue)	<u>(\$250)</u>	<u>(\$118)</u>	<u>\$34</u>	<u>(\$38)</u>	<u>(\$296)</u>
24						
25	Debt/equity issue costs	<u>\$4</u>	<u>\$0</u>	<u>\$0</u>	<u>\$1</u>	<u>\$3</u>

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CONTINUITY OF DEFERRED CHARGES

		Test Year 2010				
		(000's)				
Line	Description	<u>Actual</u> <u>Balance '09</u>	<u>Gross</u> <u>Additions</u>	<u>Tax</u>	<u>Amortization</u>	<u>Balance '10</u>
1	Rate base items					
2	Studies	3	0	0	0	3
3	Line Repair (Babcock)	0	0	0	0	0
4	Industrial Customer Deferral	(27)	0	0	(13)	(13)
5	BCUC Hearing & CAP/ROE	0	2	(1)	(0)	2
6	Property tax deferral	(1)	0	0	(1)	0
	Resource Plan	1	0	0	0	1
7	RSAM	(12)	5	(1)	0	(9)
8	Tumbler Ridge Plant Upset	0	0	0	0	0
9	Bill 198 Compliance Costs	0	0	0	0	0
10	IFRS	1	1	(0)	0	2
11		<u>(35)</u>	<u>8</u>	<u>(2)</u>	<u>(14)</u>	<u>(15)</u>
12	Average rate base for the year					<u><u>(25)</u></u>
13	Interest bearing deferrals					
14	BCUC Fees	2	0	0	2	0
15	GCVA	(245)	327	(95)	0	(13)
16	Depreciation Adjustment	(0)	0	0	0	(0)
17	Short term Interest	1	8	(2)	6	0
18	Long term Interest	(0)	(0)	0	(0)	(0)
19	Carbon / Income Tax	0	0	0	0	0
20	Cost of Service	(18)	(1)	0	(18)	(1)
21		<u>(261)</u>	<u>334</u>	<u>(97)</u>	<u>(11)</u>	<u>(14)</u>
22						
23	Total deferrals (excl. Debt Issue)	<u><u>(\$296)</u></u>	<u><u>\$342</u></u>	<u><u>(\$100)</u></u>	<u><u>(25)</u></u>	<u><u>(\$28)</u></u>
24						
25	Debt/equity issue costs	<u><u>\$3</u></u>	<u><u>\$0</u></u>	<u><u>\$0</u></u>	<u><u>1</u></u>	<u><u>\$3</u></u>

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CASH WORKING CAPITAL

FOR THE YEAR ENDED DECEMBER 31, 2010

<u>Line</u> <u>No.</u>	<u>Particulars</u>	<u>Lag/(Lead)</u> <u>Days</u>	<u>Expense</u>	<u>Working</u> <u>Capital</u>
1	Revenue	54.3		
2	Expense	<u>(29.2)</u>		
3	Operating working capital	25.1	\$1,836	\$126
4	Adjustments:			
5	Equal Billing Plan adjustment			(8)
6	PST, ICEF Levy & Carbon Tax			(0)
7	GST/HST			<u>10</u>
8	Cash working capital required			<u><u>\$129</u></u>

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

REVENUE LAG DAYS

FOR THE YEAR ENDED DECEMBER 31, 2010
(\$000's)

Line <u>No.</u>	<u>Revenues</u>	<u>Revenue Lag days</u>	<u>Normalized Revenue</u>	<u>Extended Revenue</u>
1	Residential - monthly	47.39	\$195	\$9,252
2	- bimonthly	59.88	767	45,940
3	Small commercial - monthly	42.24	\$452	19,088
4	- bimonthly	64.90	\$13	844
5	Large Commercial	41.38	234	9,672
6	Small industrial	72.2	302	21,797
7	Rate increase	54.3	90	4,905
8	Other operating revenue	54.3	12	651
9	Average revenue lag days	54.3	\$2,065	\$112,149

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

EXPENSE LEAD DAYS

FOR THE YEAR ENDED DECEMBER 31, 2010
(\$000's)

Line <u>No.</u>	<u>Revenues</u>	Expense (Lead) <u>Days</u>	Normalized <u>Expenses</u>	Extended <u>Expenses</u>
1	Gas Purchases	(40.2)	\$915	(\$36,785)
2	Operating payroll	(5.0)	259	(1,294)
3	Employee benefits	(20.9)	51	(1,070)
4	Uncollectible accounts	(54.3)	4	(233)
5	Other operating expenses	(31.4)	509	(15,971)
6	Expenses credited/capitalized	(10.6)	(12)	129
7	Insurance	182.5	11	1,963
8	Property taxes	(1.0)	80	(80)
9	Income taxes payable	(15.2)	20	(302)
		<u>(29.2)</u>	<u>\$1,836</u>	<u>(53,643)</u>

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CASH WORKING CAPITAL - GOODS AND SERVICES TAX

FOR THE 6 MONTHS ENDED JUNE 30, 2010

Line <u>No.</u>	<u>Description</u>	<u>Taxable Amount</u>	<u>G.S.T. @ 5%</u>	<u>Receipt Lag Days</u>	<u>Payment (Lead) Days</u>	<u>Net Lag/(Lead)</u>	<u>Working Capital</u>
1	Revenues						
2	Residential and commercial	\$986	49	15.6	(30.4)	(14.8)	(2.0)
3	Industrial	165	8	57.0	(60.8)	(3.8)	(0.1)
4	Carbon Tax	73	<u>4</u>	15.7	(30.4)	<u>(14.7)</u>	<u>(0.1)</u>
5							
6			<u>\$61</u>			<u>(13.3)</u>	<u>(\$2.2)</u>
7							
8							
9							
10				<u>Credit Lag Days</u>	<u>Payment Lag Days</u>	<u>Net Lag/(Lead)</u>	<u>Working Capital</u>
11							
12	Purchases						
13	Capital expenditures	\$102	5	39.6	8.2	47.8	0.7
14	Gas supply	532	27	60.8	(25.0)	35.8	2.6
15	Operating costs	254	<u>13</u>	39.6	8.2	<u>47.8</u>	<u>1.7</u>
16							
17			<u>\$44</u>			<u>40.6</u>	<u>\$4.9</u>
18							
19							<u>\$2.7</u>

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CASH WORKING CAPITAL - HST

FOR THE 6 MONTHS ENDED DECEMBER 31, 2010

Line <u>No.</u>	<u>Description</u>	<u>Taxable Amount</u>	<u>HST @ 12%*</u>	<u>Receipt Lag Days</u>	<u>Payment (Lead) Days</u>	<u>Net Lag/(Lead)</u>	<u>Working Capital</u>
1	Revenues						
2	Residential	\$434	\$22	14.8	(30.4)	(15.6)	(0.9)
3	Commercial	\$308	37	16.8	(30.4)	(13.6)	(1.4)
4	Industrial	162	19	57.0	(60.8)	(3.8)	(0.2)
5	Carbon Tax	72	9	15.7	(30.4)	(14.7)	(0.3)
6							
7			<u>\$87</u>			<u>(12.0)</u>	<u>(\$2.9)</u>
8							
9							
10							
11				<u>Credit Lag Days</u>	<u>Payment Lag Days</u>	<u>Net Lag/(Lead)</u>	<u>Working Capital</u>
12							
13	Purchases						
14	Capital expenditures	\$130	16	39.6	8.2	47.8	2.0
15	Gas supply	383	46	60.8	(25.0)	35.8	4.5
16	Operating costs	254	31	39.6	8.2	47.8	4.0
17							
18			<u>\$92</u>			<u>41.8</u>	<u>\$10.6</u>
19							
20							<u>\$7.7</u>
21	*Effective HST rate on residential sales revenue is 5% due to point of sale rebate of 7%.						

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CASH WORKING CAPITAL - PROVINCIAL SALES TAX & ICEF LEVY

FOR THE 6 MONTHS ENDED JUNE 30, 2010

Line <u>No.</u>	<u>Description</u>	<u>Taxable Amount</u>	<u>P.S.T. @ 7%</u>	<u>Receipt Lag Days</u>	<u>Payment Lag Days</u>	<u>Net Lag/(Lead)</u>	<u>Working Capital</u>
1	Revenues						
2	Commercial sales	\$416	29	16.8	(23.0)	(6.2)	(0.5)
3	Industrial sales	0	-	57.0	(23.0)	34.0	0.0
4	PST Subtotal	<u>416</u>	<u>29</u>				<u>(0.5)</u>
5							
6			ICEF Levy				
7			<u>@ 0.4%</u>				
8	Residential sales	\$570	2	14.8	(23.0)	(8.2)	(0.1)
9	Commercial sales	\$416	2	16.8	(23.0)	(6.2)	(0.0)
10	Small Industrial sales	\$0	-	57.0	(23.0)	34.0	-
11	ICEF Levy Subtotal	<u>\$986</u>	<u>\$4</u>				<u>(0.1)</u>
12							
13		Taxable	Carbon				
14	Gas sales subject to Carbon Tax	<u>GJs</u>	<u>Tax</u>				
15	Residential sales - January to June	<u>52 559</u>	<u>\$39</u>	14.8	(15.0)	(0.2)	(\$0)
16	- July to December	38 433	38	14.8	(15.0)	(0.2)	(0.0)
17	Commercial sales - January to June	45 698	34	16.8	(15.0)	1.8	0.2
18	- July to December	33 591	33	16.8	(15.0)	1.8	0.2
19	Carbon Tax Subtotal	<u>170 281</u>	<u>\$145</u>	15.7	(15.0)	0.7	\$0.3
20							
21	PST, ICEF Levy & Carbon Tax Total						<u><u>(\$0.3)</u></u>

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

CONTRIBUTIONS IN AID OF CONSTRUCTION

(000's)

Line No.	Description	Test Year 2010	NSP 2009
1	Gas Plant In Service		
2	Beginning balance	\$4,246	\$4,245
3	Additions	<u>57</u>	<u>56</u>
4	Ending balance	\$4,303	\$4,302
5	Accumulated Amortization		
6	Beginning balance	(\$3,203)	(\$3,159)
7	Additions	<u>(44)</u>	<u>(44)</u>
8	Ending balance	(\$3,247)	(\$3,203)
9	Net Total		
10	Beginning balance	\$1,044	\$1,087
11	Additions	<u>13</u>	<u>12</u>
12	Ending balance	<u><u>\$1,057</u></u>	<u><u>\$1,099</u></u>
13	Average balance	<u><u>\$1,050</u></u>	<u><u>\$1,093</u></u>

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

INCOME TAXES

SCHEDULE 3
(000's)

Line No.		Test Year 2010	NSP 2009
1	Calculation of Taxable Income		
2	Earned return before income taxes	\$150	\$124
3	Interest	(63)	(61)
4	Permanent differences	0	0
5	Timing differences	(17)	(26)
6			
7	Taxable income	\$70	\$37
8			
9	Calculation of Income Tax Expense		
10	Income taxes payable	\$20	\$11
11	Income Tax Rate Deferral	-	-
12	Deferred income tax	-	-
13			
14	Income tax expense	\$20	\$11
15			
16	Particulars of Timing Differences		
17	A. Tax Effects Subject To Flowthrough		
18	Depreciation	\$124	\$116
19	Amortization	(25)	(37)
20	Capital cost allowance	(107)	(99)
21	Deferred charges	-	-
22	Overheads capitalized	(10)	(6)
23	Other	-	-
24			
25	Timing differences	(17)	(26)
26			
27	Tax rate	28.50%	30.00%
28	Surtax rate	0.00%	0.00%
29	Deferred tax rate	28.50%	30.00%

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

COMMON EQUITY

SCHEDULE 4
(000's)

Line No.		Test Year 2010	NSP 2009
1	Opening balance		
2	Share capital	\$230	\$230
3	Contributed surplus	-	-
4	Retained earnings	345	345
5			
6		575	575
7			
8	Net income	\$67	\$51
9	Shares Issued	125	-
10	Preferred dividends	-	-
11	Common dividends	(10)	(75)
12			
13	Closing balance	\$757	\$552
14			
15			
16	Midyear common equity	\$729	\$564

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

RETURN ON CAPITAL

SCHEDULE 5
(000's)

Line No.		Test Year 2010	NSP 2009
1	Short term borrowings	\$253	\$244
2	proportion	14.73%	15.61%
3	rate of return	3.96%	2.71%
4	return component	0.58%	0.42%
5			
6	Long term debt	\$733	\$757
7	proportion	42.77%	48.39%
8	rate of return	7.22%	7.24%
9	return component	3.09%	3.50%
10			
11	Common equity	\$729	\$564
12	proportion	42.50%	36.00%
13	rate of return	9.20%	9.12%
14	return component	3.91%	3.28%
15			
16	Total capitalization	<u>\$1,715</u>	<u>\$1,565</u>
17			
18	Return on rate base	<u>7.58%</u>	<u>7.21%</u>
19			
20	Utility rate base	<u>\$1,715</u>	<u>\$1,565</u>

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

SHORT TERM DEBT

FOR THE YEAR ENDED DECEMBER 31
(000's)

	Test Year	NSP
	2010	2009
<hr/>		
1	Customer Security Deposits	
2	Average annual balance	\$69 \$69
3	Interest rate applicable to deposits	0.00% 0.00%
4	Annual Interest Expense	\$0 \$0
5		
6	Operating Line / Other	
7	Average annual draw	\$183 \$175
8	Interest rate	5.46% 3.78%
9	Annual Interest Expense	\$10 \$7
10		
11	Average short term interest rate	3.96% 2.71%

Pacific Northern Gas (N.E.) Ltd.
(Tumbler Ridge Division)

LONG TERM DEBT

FOR THE YEAR ENDED DECEMBER 31
(000's)

	Test Year 2010	NSP 2009
<hr/>		
1 Secured Debentures Series 2018		
2 Liability beginning of year	\$536	\$561
3 Sinking fund payments	(24)	(24)
4 Average Capitalization	533	557
5 Annual Interest Expense	47	49
6 Issue costs beginning of year	(2)	(3)
7 Amortization of Issue Costs	0	-
8		
9 Effective Cost Rate	8.89%	8.89%
10		
11 2007 5-year Term Intercompany Loan		
12 Liability beginning of year	\$200	\$200
13 Issue during year	-	-
14 Sinking fund payments	-	-
15 Average Capitalization	200	200
16 Annual Interest Expense	5	5
17 Issue costs beginning of year	1	2
18 Amortization of Issue Costs	1	1
19		
20 Effective Cost Rate	2.77%	2.64%
21		
22 Total Actual Debt		
23 Total Average Capitalization	733	757
24		
25 Effective Cost Rate	7.22%	7.24%



**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** G-

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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 (N.E.) Ltd.
(Fort St. John/Dawson Creek and Tumbler Ridge Divisions)
For Approval of its 2010 Revenue Requirements
for PNG (N.E.) Service Area

BEFORE: _____, Commissioner XXXXXXXXXXXXXXXXXXXX

O R D E R

WHEREAS:

- A. On October 5, 2009, Pacific Northern Gas (N.E.) Ltd. ["PNG (N.E.)"] Fort St. John/Dawson Creek ("FSJ/DC") and Tumbler Ridge ("TR") Divisions filed for approval of its 2010 Revenue Requirements Application (the "Application"). PNG (N.E.) proposes to amend its rates on an interim basis, effective January 1, 2010, pursuant to Sections 58 and 89 of the Utilities Commission Act ("the Act"); and
- B. PNG (N.E.)'s FSJ/DC Division projects a revenue deficiency of \$896,000 for Test Year 2010. This revenue deficiency results from increases in the 2010 cost of service and slightly lower revenues; and
- C. For the PNG (N.E.) FSJ/DC Division, the Application seeks approval of an overhead capitalization rate of 20.49 percent, subject to modification upon filing of the final 2010 revenue requirements application regulatory schedules; and
- D. For the PNG (N.E.) FSJ/DC Division, the Application seeks approval of the deferral accounts and amortization expenses for 2010 as set forth under Tab 2, at pages 8 and 9; and

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- E. PNG (N.E.)'s FSJ/DC Division seeks approval to continue the unaccounted for gas volume deferral account to record the difference between forecast and actual unaccounted for gas ("UAF") volumes in Test Year 2010 based on using a 1 percent of deliveries UAF loss factor for 2010 and requiring PNG (N.E.) to apply for British Columbia Utilities Commission ("Commission") approval to record actual 2010 UAF losses above 1.5 percent in the deferral account; and
- F. The PNG (N.E.) TR Division projects a revenue deficiency of \$90,000 for the Test Year 2010. This revenue deficiency is primarily the result of increases in the 2010 cost of service partially offset by higher forecast gas deliveries with corresponding higher revenues; and
- G. For the PNG (N.E.) TR Division, the Application seeks approval of an overhead capitalization rate of 5.64 percent, subject to modification upon filing of the final 2010 revenue requirements application regulatory schedules; and
- H. For the PNG (N.E.) TR Division, the Application seeks approval to continue the industrial customer transportation service deliveries deferral account in Test Year 2010; and
- I. For the PNG (N.E.) TR Division, the Application seeks approval to continue the unaccounted for gas volume deferral account to record the difference between forecast and actual UAF volumes in Test Year 2010 based on using a 0 percent of deliveries UAF loss factor for 2010 and requiring PNG (N.E.) to apply for Commission approval to record actual 2010 UAF losses above 1.0 percent in the deferral account; and
- J. The Application includes changes to PNG (N.E.)'s capital structure and rate of return as set forth in PNG(N.E.)'s Capital Structure and Equity Risk Premium Application to the Commission dated July 16, 2009; and
- K. PNG (N.E.) considers a Negotiated Settlement Process ("NSP") would be the most efficient process for the review of the Application; and
- L. The Commission considers that approving interim rates at the level sought under the Application effective January 1, 2010 and establishing a Regulatory Timetable for the registration of Intervenor and for the preliminary review of the Application, and to allow Intervenor to make written submissions on a formal review process, is necessary and in the public interest.

NOW THEREFORE pursuant to Section 89 of the Act, the Commission orders as follows:

1. The PNG (N.E.) 2010 Revenue Requirements Application Preliminary Regulatory Timetable for the PNG (N.E.) service area, attached as Appendix A, has been established.

Pacific Northern Gas (N.E.) Ltd.

Application for Approval of 2010 Revenue Requirements
for PNG (N.E.) Service Area

PRELIMINARY REGULATORY TIMETABLE

ACTION	DATES
PNG (N.E.) filed 2010 Revenue Requirements Application	Monday, October 5, 2009
PNG (N.E.) to publish Notice of Revenue Requirements Application	by Friday, October 23, 2009
Commission Information Request No. 1	Friday, October 30, 2009
Intervenor Registration	Tuesday, November 3, 2009
Intervenor Information Request No. 1	Friday, November 6, 2009
Intervenor Comments regarding Regulatory Process	Tuesday, November 10, 2009
PNG (N.E.) Response to Commission and Intervenor IRs No. 1	Friday, November 13, 2009
Commission Order setting out Regulatory Process	Tuesday, November 17, 2009
Commission and Intervenor IR No. 2, if necessary	Wednesday, Nov. 18, 2009
PNG (N.E.) Response to Commission and Intervenor IR No. 2	Wednesday, Nov. 25, 2009
Potential commencement date for Negotiated Settlement Process	Monday, November 30, 2009



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Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek and Tumbler Ridge Divisions)
Application for Approval of 2010 Revenue Requirements
for PNG (N.E.) Service Area

NOTICE OF REVENUE REQUIREMENTS APPLICATION

THE APPLICATION

On October 5, 2009, Pacific Northern Gas (N.E.) Ltd. ["PNG (N.E.)"] Fort St. John/Dawson Creek ("FSJ/DC") and Tumbler Ridge ("TR") Divisions filed its 2010 Revenue Requirements Application (the "Application") seeking approval of delivery rate increases on an interim basis pursuant to Sections 58 and 89 of the Utilities Commission Act (the "Act"), effective January 1, 2010.

For the FSJ/DC Division, the average delivery rate increase is estimated to be approximately \$32 per year for a typical residential customer consuming 113 gigajoules ("GJ") per year. This represents an increase of approximately 8.9 percent compared to October 2009 delivery rates. Similarly, an average small commercial customer consuming 564 GJ per year will pay approximately \$107 per year more for gas delivery service. This corresponds to an increase of approximately 9.2 percent compared to October 2009 delivery rates.

For the FSJ/DC Division, based on the gas cost recovery and GCVA rate riders, approved by the Commission effective October 1, 2009 and the applied for delivery rates, the overall average bundled rate decrease, for a typical residential customer consuming 113 GJ per year, is 3.2 percent, and for a small commercial customer consuming 564 GJ per year, is 2.5 percent.

For the TR Division, the average delivery rate increase is estimated to be approximately \$37 per year for a typical residential customer consuming 85 GJ per year. This represents an increase of approximately 7.8 percent compared to October 2009 delivery rates. Similarly, an average small commercial customer consuming 657 GJ per year will pay approximately \$209 per year more for gas delivery service. This corresponds to an increase of approximately 7.8 percent compared to October 2009 delivery rates.

For the TR Division, based on the gas cost recovery and GCVA rate riders, approved by the Commission effective October 1, 2009 and the applied for delivery rates, the overall average bundled rate decrease, for a typical residential customer consuming 85 GJ per year, is 5.2 percent, and for a small commercial customer consuming 657 GJ per year, is 4.6 percent.

PUBLIC INSPECTION OF THE APPLICATION

The Application and supporting material will be made available for inspection at public libraries in Fort St. John, Dawson Creek, and Tumbler Ridge, and at the Head Office of PNG (N.E.) 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 Intervenor materials (<http://www.bcuc.com/Proceeding.aspx?ApplicationType=Current>).

REGISTERING TO PARTICIPATE

Persons who expect to actively participate in this proceeding are required to register as Intervenors with the Commission, in writing or electronic submission, by Tuesday, November 3, 2009, identifying their interest in the Application and the issues they intend to pursue and the nature and extent of their anticipated involvement in the review process.

Persons not expecting to actively participate, but who have an interest in the proceeding should register as Interested Parties with the Commission, in writing or electronic submission, by Tuesday, November 3, 2009, identifying their interest in the Application.

All submissions and/or correspondence received from active participants or the 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. Erica M. Hamilton, Commission Secretary, or Mr. Philip Nakoneshny, Director, Rates and Finance, as follows:

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