

PACIFIC NORTHERN GAS (N.E.) LTD.

(Fort St. John/Dawson Creek Division)

2010 Revenue Requirements Application

to the

B.C. Utilities Commission

October 5, 2009



Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek 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.
(Fort St. John/Dawson Creek 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 Fort St. John/Dawson Creek ("FSJ/DC") 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 Fort St. John/Dawson Creek 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 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 the Test Year 2010 figures to the 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 2010	NSP 2009	Difference	
			Total	Subtotal
Operating				
Labour	1,561	1,490	70	
Other	2,371	2,303	68	
Sub-total	<u>3,931</u>	<u>3,793</u>	<u>138</u>	
Maintenance				
Labour	88	71	17	
Other	195	152	43	
Sub-total	<u>283</u>	<u>223</u>	<u>60</u>	
Administrative and General				
Labour	0	0	0	
Total Company Benefits	475	441	33	
Other	1,146	1,096	49	
Sub-total	<u>1,621</u>	<u>1,538</u>	<u>83</u>	
Total (O, M, A & G) Excluding Co. Use	5,835	5,553	281	281
Transfers to Capital Operating	(248)	(207)	(41)	
Transfers to Capital Admin. & Gen.	(258)	(208)	(50)	
Property Taxes	1,052	977	74	
Depreciation	1,522	1,430	91	
Amortization	19	(43)	62	
Other Income	(196)	(187)	(9)	
NSP Settlement Allowance for Shared Services	0	(23)	23	152
Total Expenses Excluding Co. Use	<u>7,725</u>	<u>7,292</u>	<u>433</u>	<u>433</u>
Income Taxes	376	283	93	
Return on Common Equity	1,508⁽¹⁾	1,161⁽²⁾	346	
Short Term Debt	81	82	(1)	
Long Term Debt	800	790	10	448
Total Cost of Service Excluding Co. Use	<u>10,489</u>	<u>9,608</u>	<u>882</u>	<u>882</u>
Company Use Gas	429	542		
Total Cost of Service Including Co. Use	<u>10,919</u>	<u>10,150</u>		
2009 to 2010 Cost of Service Increase (Decrease)			882	
2009 to 2010 Margin Decrease (Increase)			15	
2010 Revenue Deficiency (Sufficiency)			<u>896</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 figures under NSP 2009. 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	\$5,835	\$5,553	\$282
Transfers to Capital, Operating, Administrative and General	(506)	(415)	(91)
Other Cost of Service items including property taxes and depreciation	2,396	2,154	242
Return components including return on equity, income taxes and debt costs	2,764	2,316	448
Cost of Service Ex. Co. Use Gas Cost	\$10,489	\$9,608	\$881
Margin Using 2009 Rates	\$9,593	\$9,608	\$15
Total Test Year 2010 Revenue Deficiency			\$896
Total Cost of Service Ex. Co. Use Gas	\$10,489	\$9,608	
Company use gas cost pass through	\$429	542	
Total Cost of Service including Company Use Gas Cost	\$10,918	\$10,150	

The following provides the main reasons for the Test Year 2010 cost of service being higher than the NSP 2009 cost of service.

OPERATING EXPENSES

The Table below sets forth historical operating expenses in comparison to the Test Year 2010 applied for amounts.

BCUC Account	\$000's						
	Test Year 2010	NSP 2009	2010/09 Difference	Actual 2008	Actual 2007	Actual 2006	Actual 2005
670 – Supervision	\$453	\$441	\$12	\$410	\$435	\$375	\$232
675 – Mains and Services	338	309	29	356	306	268	255
685 – General Operations	198	189	9	227	221	236	283
688 – Other General Operations	549	527	22	481	459	466	391
711/713/714 Customer Care	462	469	(7)	336	325	315	293
712 Meter Reading	202	187	15	223	175	177	153
Add Shared Service Costs	1,038	1,000	38	927	844	829	735
718 Uncollectible Accounts	119	159	(40)	156	153	150	198
Other Including 665 Expenses	573	512	61	497	456	392	464
Subtotal	\$3,931	\$3,793	\$138	\$3,613	\$3,374	\$3,208	\$3,004
Transfers to Capital	(248)	(207)	(41)	(200)	(192)	(193)	(177)
Operating Expenses Excluding Co. use gas cost	\$3,683	\$3,586	\$97	\$3,413	\$3,182	\$3,015	\$2,827

The figures in the above Table exclude the Company use gas operating cost as that is treated as a pass through cost since it is dependant on prevailing gas supply market prices.

The following provides more detailed information on NSP 2009 to Test Year 2010 changes in operating costs as summarized by Commission Account number in the above Table.

Account 675 – Mains and Services

The forecast expenditures in the distribution mains Account 675 reflects increased time allocated to cathodic protection activities and monitoring to ensure the ongoing safe operation of the distribution system.

Account 688 – Other General Operations

The forecast expenditures in the other general operations Account 688 are increasing in 2010 compared to 2009 as a result of the wage rate adjustment to the unionized workforce and the corresponding auto expense allocation.

Account 712 – Meter Reading

The increase in forecast costs for meter reading is more reflective of actual expenses incurred in performing this work.

Account 665 - Pipelines

This Account is included in the Other Expenses in the above table. It is increasing from \$83,000 under NSP 2009 to \$110,000 in Test Year 2010. The increase reflects higher labour cost allocation to this account to allow compliance with new regulations established by the Explosive Regulatory Department of the Federal Ministry of Mines and Resources. The new regulations now require daily checks of explosive material storage which has resulted in \$15,000 of additional labour allocated to this account. Contractor expenses of \$13,000 for brush clearing on right of ways are also reflected in the Test Year 2010 forecast of expenditures.

MAINTENANCE COSTS

BCUC Account	\$000's						
	Test Year 2010	NSP 2009	2010/2009 Difference	Actual 2008	Actual 2007	Actual 2006	Actual 2005
867 Reg. Stations	\$44	\$39	\$5	\$38	\$24	\$27	\$44
875 Mains/Services	137	102	35	98	158	65	196
878 Meters	57	47	10	45	27	45	59
All other	45	35	10	35	18	12	63
Total	\$283	\$223	\$60	216	227	\$149	\$362

PNG(N.E.)'s overall 2010 planned maintenance activities at a budgeted cost of \$283,000 are responsive to system needs and are at a level PNG(N.E.) considers will ensure PNG(N.E.)'s facilities are kept in good working order and ensure continued safe, reliable and secure gas delivery service to its customers. See Tab 1, Page 4 for the detailed budget figures. The forecast expenditures for transmission pipelines under Account 865 are increasing by \$9,000 to reflect increased time to complete the required pipeline line marker post and valve maintenance throughout the Fort St. John/Dawson Creek service area. Account 875 Mains and Services maintenance expenditures are increasing \$35,000 to be more reflective of the recent actual expenditures in this area. Lastly, meter repair costs in Account 878 are forecast to be \$10,000 higher in 2010.

ADMINISTRATIVE AND GENERAL COSTS

\$000's							
Cost Element	Test Year 2010	NSP 2009	2010/2009 Difference	Actual 2008	Actual 2007	Actual 2006	Actual 2005
721 Administration	\$3	\$2	\$2	\$2	\$4	\$2	\$7
Add 721 Shared Service Costs	782	726	57	664	641	592	481
722 Audit/Legal Fees	76	77	(1)	54	26	32	15
723 Insurance	123	144	(21)	129	132	137	161
725 Employee Ben.	475	\$441	33	460	490	486	407
728 General	43	42	1	41	41	45	51
Add 728 Shared Service Costs	119	105	14	93	92	86	0
Sub-total	1,621	1,537	84	1,443	1,426	1,380	1,122
Less: Transfers to Capital	(258)	(208)	(50)	(203)	(217)	(201)	(163)
Total	\$1,363	\$1,329	\$34	\$1,240	\$1,209	\$1,179	\$959

Administrative and general costs, net of transfers to capital, have increased from \$1,329,000 under NSP 2009 to \$1,363,000 in Test Year 2010, an increase of \$34,000. The increase reflects higher administrative shared services charged by PNG (i.e. the parent company of PNG(N.E.)) under Account 721 of \$57,000 and higher shared service costs of \$14,000 for Account 728. The higher Account 721 costs reflect head office cost increases for PNG to reflect two full time positions that had been part time in 2009 to enable PNG to comply with more detailed financial and corporate reporting requirements and to manage human resources workload. Account 728 costs are increasing to reflect corresponding increases faced by PNG.

SHARED SERVICE CHARGES BY PNG TO PNG(N.E.)

The following Table summarizes the shared service charges allocated by PNG to PNG(N.E.)’s Fort St. John/Dawson Creek 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.

Costs Allocated	\$000’s					
	Test Year 2010	NSP 2009	2010/09 Change	Actual 2008	Actual 2007	Actual 2006
721: Administration	\$650	\$604	\$46	\$543	\$513	\$478
Benefits	133	123	10	121	125	114
685: General Ops.	383	361	22	324	260	278
Benefits	84	83	1	82	74	73
711/713/714: Customer Care	475	466	9	432	411	386
Benefits	96	89	7	90	98	93
728: Corporate	119	105	14	93	92	84
Subtotals: Allocated	1,624	1,536	98	1,392	1,275	1,226
Benefits	314	295	19	293	297	280
Total	\$1,938	\$1,831	\$107	\$1,685	\$1,573	\$1,506

Shared service charges by PNG to PNG(N.E.)’s FSJ/DC division are projected to increase in 2010 from 2009 levels due to cost increases facing PNG in respect of each of the above items. PNG noted in the following in PNG-West 2010 revenue requirements application with respect to administrative cost increases:

“The workload associated with complying with accounting and regulatory reporting requirements continues to accelerate and requires sophisticated staff with a high degree of understanding and knowledge of the regulatory environment, the current accounting standards and future accounting standards. Financial reporting is much more detailed having regard to the emphasis on full disclosure by public reporting companies and the need to apply and ensure that internal controls for financial reporting are adequate. In addition, the time and effort required to transition the Company to International Financial Reporting Standards (“IFRS”) will engage almost all of the accounting staff to some extent. This includes the new Controller whose full time salary, at a higher level than originally forecast, is reflected in this Application compared to 10 months salary under NSP 2009.”

TRANSFERS TO CAPITAL

Cost Element	\$000's					
	Test Year 2010	NSP 2009	2010/09 Difference	Actual 2008	Actual 2007	Actual 2006
Operating	\$248	\$207	\$43	\$200	\$192	\$193
Administration	\$259	\$208	47	\$203	\$217	\$201
% of Overhead Allocated	20.49%	17.82%	2.67%	18.0%	18.6%	18.6%

The allocation of overhead to capital projects for 2010 has been calculated using a rate of 20.49 percent, compared to 17.82 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. Direct capital labour is higher in 2010 primarily due to the workload associated with installing services in the Tomslake area. PNG(N.E.) is requesting Commission approval to fix the transfer rate for 2010 at 20.49 percent of actual overhead expenses. This figure will be updated when the final 2010 regulatory schedules are filed with the Commission.

PROPERTY TAXES

Cost Element	\$000's					
	Test Year 2010	NSP 2009	2009/2008 Difference	Actual 2009	Actual 2008	Actual 2007
Property Taxes	\$809	\$755	\$54	\$767	\$698	\$670
1% in Lieu	243	223	20	223	260	217
Total	\$1,052	\$977	\$74	\$990	\$958	\$887

Actual 2009 property taxes were higher than forecast under NSP 2009 due to higher mill rates than originally anticipated. The Test Year 2010 provision is also higher than actual property taxes of \$767,000 in 2009 to reflect the combined impact of anticipated mill rate increases in the range of 3 percent and higher assessment values resulting from additional installations. The 1 percent in lieu tax is based on revenues received in 2008.

DEPRECIATION

Test Year 2010	NSP 2009	2010/2009 Difference
\$1,522,000	\$1,430,000	\$92,000

Depreciation expense is calculated using the applicable fixed percentage rate times the gross plant cost, for each category of plant asset. The increase in depreciation from 2009 to 2010 is primarily due higher gross plant subject to depreciation.

AMORTIZATION

Test Year 2010	NSP 2009	2010/2009 Difference
\$19,000	(\$43,000)	\$62,000

The amortization expense details are provided under Tab 2. The major changes from NSP 2009 to Test Year 2010 are summarized as follows:

Deferral Account	Amortization Expense (\$000's)		
	Test Year 2010	NSP 2009	2010/2009 Difference
Property Tax	\$8	\$24	(\$16)
BCUC Hearing inc. CAP/ROE App.	8	1	7
DC Industrial Deliveries	10	4	6
Resource Plans	13	0	13
Bill 198 Compliance	9	9	0
BCUC Fees	(11)	(6)	(5)
Short Term Interest	20	(10)	36
Long Term Interest	(39)	(62)	23
Carbon/Income Tax	0	(3)	3
IFRS	0	0	0
Total	\$19	(\$43)	\$62

The above Table shows that amortization expense from NSP 2009 to Test Year 2010 is increasing by a net amount of \$62,000. The Dawson Creek industrial customer subject to the industrial customer deliveries deferral account is taking less gas in 2009 than budgeted. Hence the debit addition in 2009 to this account and corresponding increase in amortization expense in 2010. The PNG(N.E.) Resource Plan was approved by the Commission in late 2008 and the cost of preparing the plan 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 FSJ/DC as a result of growth in that service area relative to the PNG-West service area. Credit amortization is less with regard to long term debt as the forecast NSP 2009 long term debt rate was closer to the actual rate in 2009 resulting in a lower projected credit balance at year end 2009.

OTHER INCOME

Test Year 2010	NSP 2009	2010/2009 Difference
\$196,000	\$187,000	\$1

The other income forecast is higher primarily due to the estimated \$10 per month fees to be paid by new Tomslake customers that choose option of paying a monthly fixed fee of \$10 rather than making a lump sum up front contribution to the cost of the new Tomslake gas distribution system.

INCOME TAXES

Test Year 2010	NSP 2009	2010/2009 Difference
\$376,000	\$283,000	\$93,000

The Test Year 2010 income taxes are higher compared to NSP 2009 primarily due to higher return on common equity and higher non deductible 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%	8.87%	0.33%
Common Equity Thickness	42.5%	36%	6.5%
Common Equity (000's)	\$16,388	\$13,089	\$3,299
Return on Equity (000's)	\$1,508	\$1,161	\$346

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 40 to 75 basis points for the FSJ/DC division. The increase in the rate of return on equity from 8.87 to 9.20 percent reflects the impact of the 35 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 2010	2010/2009 Difference
Short-term debt	\$81,000	\$82,000	(\$1,000)
Long-term debt	\$800,000	\$790,000	\$10,000

The interest rate on short-term debt is forecast to average 3.23 percent in 2010 versus a forecast of 2.41 percent under NSP 2009. Short term debt is comprised of customer security deposits and operating line draws. The interest rates on both components of short term debt are forecast to be higher in 2010 (see Tab 5, page 2). The higher interest rate is offset by lower short term debt in the capital structure.

Long-term debt interest expense has increased compared to the NSP 2009 provision due to slightly lower projected balance being offset by a slightly higher projected embedded cost of long debt rate. 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
68,497 GJ	68,603 GJ	(106 GJ)
\$429,000	\$510,000	(\$81,000)

The volume of Company use gas forecast for Test Year 2010 is slightly lower than the forecast under NSP 2009. A lower forecast unit cost of gas contributes to the projected cost reduction.

CAPITAL ADDITIONS

	Test Year 2010	NSP 2009	2010/2009 Difference
Additions including overhead	\$3,049,000	\$2,818,000	\$189,000
Less overhead	(637,000)	(548,000)	(\$29,000)
Net	\$2,412,000	\$2,270,000	\$142,000

The major capital additions planned for 2010 are summarized in the Table below.

Description	Budgeted Cost
Facility Modifications	\$186,000
Structure and Grounds Upkeep	176,000
Distribution System	700,000
Mobile/Heavy Equipment	80,000
New Additions	938,000
Customer Growth	195,000
Total	\$2,275,000

The expenditures shown above are considered necessary to ensure PNG(N.E.) continues to provide its customers with safe, reliable and secure gas delivery service in 2010. These projects account for approximately 94 percent of the total capital expenditures forecast for 2010, excluding overhead. The first four items in the Table are required to sustain operations at appropriate service levels. Information about each of the projects identified above is provided below.

Facility Modifications - \$157,000

These are modifications to existing facilities to improve their operational safety and reliability. The activities planned for 2010 include: continuing to add secondary odorant containment and station alarms to certain facilities, the lowering of a section of high pressure line due to safety and operational concerns, and replacement of a number of obsolete regulators and associated equipment.

Structure and Grounds Upkeep - \$176,000

A number of smaller projects in 2010 are focused on ensuring continued access and safe operation of pressure reducing facilities and general office buildings. The largest single project is the addition of a cold storage shed at a cost of \$45,000. This unheated enclosure will help to maintain seasonal equipment and contribute to longer useful life accordingly.

Distribution System - \$700,000

The largest project is the continued removal of mechanical couplings on the distribution system. This activity will occur in both Dawson Creek and Fort St. John at a forecast cost of \$340,000. The other main activity in this area is the continued replacement of PE 2306 pipe at an estimated cost of \$220,000. The replacement of a bridge crossing (\$51,000) and a number of smaller projects accounts for the remainder of the distribution system capital projects.

Mobile/Heavy Equipment - \$80,000

The mobile/heavy equipment budget in 2010 includes the replacement of a tamper (\$9,000), acquisition of bi-directional hydraulics for the existing skid steer loader (\$10,000) and other minor construction equipment. The single largest item is the replacement of a service truck that has met PNG(N.E.)'s replacement criteria of 7 years or 160,000 kilometres with a forecast expenditure of \$41,000.

New Additions - \$938,000

The cost of new service additions (\$501,000), new mains (\$201,000) and new and replacement meters and meter sets (\$236,000) make up the expenditures for 2010. A large component of the 2010 budget pertains to service lines required for the new Tomslake service area.

Customer Growth - \$195,000

Several smaller projects to ensure the operational reliability and adequacy of the system to meet the load demands placed on it are forecast for 2010. The two largest projects are the addition of an indirect fired lineheater at an existing pressure reducing facility at a cost of \$41,000 and rebuilding a pressure control station for \$34,000. In addition a variety of upgrades to smaller stations are also required. This work is required due to increased customer load creating potential pressure regulation issues if left unaddressed.

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 call Response Statistics

<u>Description</u>	<u>2009 YTD Results</u>	<u>2008 Results (12 months)</u>
Number of emergency calls	397	461
Average response time per call	17 minutes	18 minutes
Number of calls with response time over 40 mins.	16	19

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 discuss in its update 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.

Other Core Market Customers

The following summarizes the projected 2010 deliveries to the large commercial firm, small industrial sales and transportation service customers for both Fort St. John and Dawson Creek in comparison to forecast deliveries under NSP 2009.

	Fort St. John (GJ's)		
Customer Class	Test Year 2010	NSP 2009	Difference
Large Commercial Sales	161,600	176,500	(14,900)
Commercial T-Service	31,500	0	31,500
Small Industrial Sales	135,000	135,000	0
Small Industrial T-Service	1,113,655	1,210,800	(97,145)

There were no projected deliveries to commercial transportation service customers under NSP 2009 as a gas marketer failed in 2008 resulting in all of the transportation service customers reverting back to sales. A new marketer was able to enter contracts with a number of these customers part way through 2009. Hence the reason for a gas delivery forecast for 2010 for this customer class. Deliveries to the commercial transportation market is the primary reason for lower large commercial sales figure.

Small industrial transportation service is lower primarily due to Canfor's Fort St. John sawmill converting to a new energy system in 2009 and switching from RS7 to RS4 effective November 1, 2009. Canfor is estimated to consume just 10,000 GJ in 2010, a reduction of 137,000 compared to the forecast for this customer under NSP 2009. The decrease has been offset by one customer switching from RS4 industrial sales to RS6 transportation service and higher projected deliveries to another customer compared to their NSP 2009 forecast.

Dawson Creek (GJ's)			
Customer Class	Test Year 2010	NSP 2009	Difference
Large Commercial Sales	143,500	187,200	(43,700)
Commercial T-Service	35,000	0	35,000
Small Industrial Sales	54,008	70,312	(16,304)

The large commercial sales decrease is due to the return of sales customers to transportation service. The small industrial sales decrease reflects a decreased forecast for the customer that is subject to the industrial customer deliveries deferral account to reflect much lower gas consumption in 2009 which is expected to prevail in 2010 as well.

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. The annual forecast of deliveries to other customer classes is provided for each of the Fort St. John and Dawson Creek service areas. 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 under 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

A Table is provided under Tab Rates to show the projected year-end 2009 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 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(N.E.) 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 the forecast gas prices and the quantity of gas PNG(N.E.) expects to purchase for Company use. The calculation of the indicative 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 to determine the recovery rate to be embedded in 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.

Bill Comparison of Current Rates and January 2010 Rates

PNG(N.E.) includes under Tab Rates a comparison of the projected annual gas bills for residential and small commercial customers using current rates effective October 1, 2009 and proposed January 1, 2010. The bill comparison focuses on the delivery rate increase that is required to recover the forecast 2010 revenue deficiency by keeping the other components of the bundled gas rate (i.e. GCVA riders, RSAM rider and gas supply charge) at the levels approved effective October 1, 2009. However, for further context, the bundled rates effective January 1, 2009 are also compared to the bundled proposed rates effective January 1, 2010 to show the year over year change. The bill comparisons for each of the Fort St. John and Dawson Creek service areas are separately discussed below since the delivery rates are different in each service area.

Fort St. John

The average rate increase for residential customers is estimated to be 8.7 percent on the delivery charge component of rates or \$32 per year for an average customer. This assumes a bundled average rate of \$9.075/GJ which is \$11.805/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 8.1 percent on the delivery charge component of rates or \$102 per year for an average customer. This assumes a bundled average rate of \$8.116/GJ which is \$11.304/GJ lower than the electricity equivalent rate of \$19.42/GJ assuming a 90 percent gas to electricity efficiency factor.

Dawson Creek

The average rate increase for residential customers is estimated to be 9.2 percent on the delivery charge component of rates or \$31 per year for an average customer. This assumes a bundled average rate of \$8.902/GJ which is \$11.9786/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 10.6 percent on the delivery charge component of rates. This assumes a bundled average rate of \$6.819/GJ which is \$12.601/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 20.49 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 1 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 1.5 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.
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**Pacific Northern Gas (N.E.) Ltd.
(Fort St. John 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	\$7.00		\$7.00	\$0.00
Delivery Charge	2.377	0.281	2.658	0.281
Company Use	0.094		0.094	-
GCVA Co. Use Rider	(0.081)		(0.081)	-
RSAM	0.095		0.095	-
	-			-
Subtotal Delivery	2.485	0.281	2.766	0.281
Gas Supply Demand	0.046		0.046	-
Gas Supply Commodity	5.577		5.577	-
GCVA Commodity Rider	(0.787)		(0.787)	-
Subtotal Commodity	4.836	-	4.836	-
Total	7.321	0.281	7.602	0.281
<u>Small Commercial (RS2)</u>				
Monthly Fixed Charge	\$7.00		\$7.00	\$0.00
Delivery Charge	2.086	0.191	2.277	0.191
Company Use	0.094		0.094	-
GCVA Co. Use Rider	(0.081)		(0.081)	-
RSAM	0.095		0.095	-
	-			-
Subtotal Delivery	2.194	0.191	2.385	0.191
Gas Supply Demand	0.044		0.051	0.007
Gas Supply Commodity	5.573		5.573	-
GCVA Commodity Rider	(0.787)		(0.787)	-
Subtotal Commodity	4.830	-	4.837	0.007
Total	7.024	0.191	7.222	0.198
<u>Large Commercial (RS3)</u>				
Monthly Fixed Charge	\$150.00		\$150.00	\$0.00
Delivery Charge	1.589	0.144	1.733	0.144
Company Use	0.094		0.094	-
GCVA Co. Use Rider	(0.081)		(0.081)	-
	-			-
Subtotal Delivery	1.602	0.144	1.746	0.144
Gas Supply Demand	0.045		0.045	-
Gas Supply Commodity	5.544		5.544	-
GCVA Commodity Rider	(0.787)		(0.787)	-
Subtotal Commodity	4.802	-	4.802	-
Total	6.404	0.144	6.548	0.144

**Pacific Northern Gas (N.E.) Ltd.
(Fort St. John 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>Commercial Transportation (RS2)</u>				
Monthly Fixed Charge	\$125.00		\$125.00	\$0.00
Delivery Charge	1.586	0.161	1.747	0.161
Company Use	0.094		0.094	-
GCVA Co. Use Rider	(0.081)		(0.081)	-
Subtotal Delivery	1.599	0.161	1.760	0.161
<u>Small Industrial (RS4)</u>				
Monthly Fixed Charge	\$410.00		\$410.00	\$0.00
Delivery Charge	0.758	0.104	0.862	0.104
Company Use	0.094		0.094	-
GCVA Co. Use Rider	(0.081)		(0.081)	-
Subtotal Delivery	0.771	0.104	0.875	0.104
Gas Supply Demand	0.018		0.018	-
Gas Supply Commodity	5.537		5.537	-
GCVA Commodity Rider	(0.787)		(0.787)	-
Subtotal Commodity	4.768	-	4.768	-
Total	5.539	0.104	5.643	0.104
<u>Small Industrial Service (RS6)</u>				
Monthly Fixed Charge	\$410.00		\$410.00	\$0.00
Delivery Charge	0.9446	0.1006	1.0452	0.1006
Company Use	0.0940		0.0940	-
GCVA Co. Use Rider	(0.0810)		(0.0810)	-
Subtotal Delivery	0.9576	0.1006	1.0582	0.1006
<u>Small Industrial Service (RS7)</u>				
Monthly Fixed Charge	\$3,000.00			
Delivery Charge	0.1977	n.a.		
Company Use	0.0940			
GCVA Co. Use Rider	(0.081)			
Subtotal Delivery	0.2107	-	-	-
Authorized Overrun	0.4437	n.a.	0.4437	0.0000

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John 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
Small Industrial Service (RS9)				
Monthly Fixed Charge	\$8,547.04		\$8,547.04	\$0.00
Delivery Charge	0.4485	0.1795	0.6280	0.1795
Company Use	0.0940		0.0940	-
GCVA Co. Use Rider	(0.0810)		(0.0810)	-
Subtotal Delivery	0.4615	0.1795	0.6410	0.1795
Small Industrial Service (RS10)				
Monthly Fixed Charge	\$3,095.00		\$3,095.00	\$0.00
Delivery Charge	0.1700	0.0845	0.2545	0.0845
Company Use	0.0940		0.0940	-
GCVA Co. Use Rider	(0.0810)		(0.0810)	-
Subtotal Delivery	0.1830	0.0845	0.2675	0.0845
Small Industrial Service (RS11)				
Monthly Fixed Charge	\$3,095.00		\$3,095.00	\$0.00
Delivery Charge	0.1920	0.0587	0.2507	0.0587
Company Use	0.0940		0.0940	-
GCVA Co. Use Rider	(0.0810)		(0.0810)	-
Subtotal Delivery	0.2050	0.0587	0.2637	0.0587

Pacific Northern Gas (N.E.) Ltd.
 (Dawson Creek 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
Residential (RS1)				
Monthly Fixed Charge	\$7.00		\$7.00	\$0.00
Delivery Charge	2.179	0.281	2.460	0.281
Company Use	0.094		0.094	-
GCV A Co. Use Rider	(0.081)		(0.081)	-
RSAM	0.095		0.095	-
Subtotal Delivery	2.287	0.281	2.568	0.281
Gas Supply Demand	0.046		0.046	-
Gas Supply Commodity	5.577		5.577	-
GCV A Commodity Rider	(0.787)		(0.787)	-
Subtotal Commodity	4.836	-	4.836	-
Total	7.123	0.281	7.404	0.281
Small Commercial (RS2)				
Monthly Fixed Charge	\$7.00		\$7.00	\$0.00
Delivery Charge	1.549	0.191	1.740	0.191
Company Use	0.094		0.094	-
GCV A Co. Use Rider	(0.081)		(0.081)	-
RSAM	0.095		0.095	-
Subtotal Delivery	1.657	0.191	1.848	0.191
Gas Supply Demand	0.044		0.044	-
Gas Supply Commodity	5.573		5.573	-
GCV A Commodity Rider	(0.787)		(0.787)	-
Subtotal Commodity	4.830	-	4.830	-
Total	6.487	0.191	6.678	0.191
Large Commercial (RS3)				
Monthly Fixed Charge	\$150.00		\$150.00	-
Delivery Charge	1.041	0.144	1.185	0.144
Company Use	0.094		0.094	-
GCV A Co. Use Rider	(0.081)		(0.081)	-
Subtotal Delivery	1.054	0.144	1.198	0.144
Gas Supply Demand	0.045		0.045	-
Gas Supply Commodity	5.544		5.544	-
GCV A Commodity Rider	(0.787)		(0.787)	-
Subtotal Commodity	4.802	-	4.802	-
Total	5.856	0.144	6.000	0.144

Pacific Northern Gas (N.E.) Ltd.
 (Dawson Creek 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
Commercial Transportation (RS2)				
Monthly Fixed Charge	\$125.00		\$125.00	-
Delivery Charge	1.038	0.161	1.199	0.161
Company Use	0.094		0.094	-
GCV A Co. Use Rider	(0.081)		(0.081)	-
Subtotal Delivery	1.051	0.161	1.212	0.161
Small Industrial (RS4)				
Monthly Fixed Charge	\$410.00		\$410.00	-
Delivery Charge	1.026	0.104	1.130	0.104
Company Use	0.094		0.094	-
GCV A Co. Use Rider	(0.081)		(0.081)	-
Subtotal Delivery	1.039	0.104	1.143	0.104
Gas Supply Demand	0.018		0.018	-
Gas Supply Commodity	5.537		5.537	-
GCV A Commodity Rider	(0.787)		(0.787)	-
Subtotal Commodity	4.768	-	4.768	-
Total	5.807	0.104	5.911	0.104

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

Bill Comparison
 October 2009 to January 2010

FORT ST. JOHN AREA

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:	115.1 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.730	84.00	0.730	84.00	0.00	
Delivery Charge		2.471	284.41	2.751	316.58	32.17	
GCVA Co. Use Rider		(0.081)	(9.32)	(0.081)	(9.32)	0.00	
RSAM Rider		0.095	10.93	0.095	10.93	0.00	
			370.02		402.20	32.17	8.7%
Gas Supply Charge		5.623	647.21	5.623	647.21	0.00	
GCVA Rider		(0.787)	(90.58)	(0.787)	(90.58)	0.00	
			556.62		556.63	0.01	0.0%
Carbon Tax		0.745	85.75	0.745	85.75	0.00	
		\$8.796 /GJ	\$1,012.40	\$9.075 /GJ	\$1,044.58	\$32.18	3.2%
Permanent Rates Effective Jan. 1, 2009 compared to Proposed Rates Jan. 1, 2010							
		\$11.188 /GJ	\$1,287.74	\$9.075 /GJ	\$1,044.58	(243.16)	-18.9%
Small Commercial:	533.9 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.157	84.00	0.157	84.00	0.00	
Delivery Charge		2.180	1,163.90	2.370	1,265.40	101.50	
GCVA Co. Use Rider		(0.081)	(43.25)	(0.081)	(43.25)	0.00	
RSAM Rider		0.095	50.72	0.095	50.72	(0.00)	
			1,255.38		1,356.87	101.49	8.1%
Gas Supply Charge		5.617	2,998.92	5.617	2,998.92	0.00	
GCVA Rider		(0.787)	(420.18)	(0.787)	(420.18)	(0.00)	
			2,578.74		2,578.74	0.00	0.0%
Carbon Tax		0.745	397.76	0.745	397.76	0.00	
		\$7.926 /GJ	\$4,231.87	\$8.116 /GJ	\$4,333.37	\$101.50	2.4%
Permanent Rates Effective Jan. 1, 2009 compared to Proposed Rates Jan. 1, 2010							
		\$10.345 /GJ	\$5,523.20	\$8.116 /GJ	\$4,333.37	-1,189.83	-21.5%

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

Bill Comparison
 October 2009 to January 2010

DAWSON CREEK AREA

Customer Classification	Annual Use	Permanent Rates Oct. 1, 2009 \$/GJ	Annual Bill Estimate \$	Proposed Rates Jan. 1, 2010 \$/GJ	Annual Bill Estimate \$	Annual Bill Difference	
						\$	%
Residential:	111.4 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.754	84.00	0.754	84.00	0.00	
Delivery Charge		2.273	253.21	2.553	284.35	31.14	
GCVA Co. Use Rider		(0.081)	(9.02)	(0.081)	(9.02)	0.00	
RSAM Rider		0.095	10.58	0.095	10.58	0.00	
Interim Rate Refund Rider		0.000	0.00	0.000	0.00	0.00	
			338.77		369.91	31.14	9.2%
Gas Supply Charge		5.623	626.40	5.623	626.40	(0.00)	
GCVA Rider		(0.787)	(87.67)	(0.787)	(87.67)	0.00	
			538.73		538.73	(0.00)	0.0%
Carbon Tax		0.745	82.99	0.745	82.99	0.00	
		\$8.622 /GJ	\$960.50	\$8.902 /GJ	\$991.63	\$31.14	3.2%
Permanent Rates Effective Jan. 1, 2009 compared to Proposed Rates Jan. 1, 2010							
		\$11.014 /GJ	\$1,226.96	\$8.902 /GJ	\$991.63	(235.33)	-19.2%
Small Commercial:	593.2 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.142	84.00	0.142	84.00	0.00	
Delivery Charge		1.643	974.63	1.833	1,087.40	112.77	
GCVA Co. Use Rider		(0.081)	(48.05)	(0.081)	(48.05)	0.00	
RSAM Rider		0.095	56.35	0.095	56.35	0.00	
			1,066.93		1,179.70	112.77	10.6%
Gas Supply Charge		5.617	3,332.00	5.617	3,332.00	0.00	
GCVA Rider		(0.787)	(466.85)	(0.787)	(466.85)	0.00	
			2,865.16		2,865.16	0.00	0.0%
Carbon Tax		0.745	441.93	0.745	441.93	0.00	
		\$6.629 /GJ	\$3,932.09	\$6.819 /GJ	\$4,044.86	\$112.77	2.9%
Permanent Rates Effective Jan. 1, 2009 compared to Proposed Rates Jan. 1, 2010							
		\$9.793 /GJ	\$5,809.21	\$6.819 /GJ	\$4,044.86	(1,764.35)	-30.4%

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

Bill Comparison
 October 2009 to January 2010
 Average of Fort St. John and Dawson Creek

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:	113.3 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.742	84.00	0.742	84.00	0.00	
Delivery Charge		2.372	268.63	2.652	300.28	31.66	
GCVA Co. Use Rider		(0.081)	(9.17)	(0.081)	(9.17)	0.00	
RSAM Rider		0.095	10.76	0.095	10.76	0.00	
			354.21		385.87	31.66	8.9%
Gas Supply Charge		5.623	636.80	5.623	636.80	(0.00)	
GCVA Rider		(0.787)	(89.13)	(0.787)	(89.13)	(0.00)	
			547.68		547.67	(0.01)	0.0%
Carbon Tax		0.745	84.37	0.745	84.37	(0.00)	
		\$8.709 /GJ	\$986.26	\$8.988 /GJ	\$1,017.91	31.65	3.2%
Permanent Rates Effective Jan. 1, 2009 compared to Proposed Rates Jan. 1, 2010							
		\$11.101 /GJ	\$1,257.74	\$8.988 /GJ	\$1,017.91	(\$239.83)	-19.1%
Small Commercial:	563.6 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.149	84.00	0.149	84.00	0.00	
Delivery Charge		1.912	1,077.23	2.102	1,184.36	107.13	
GCVA Co. Use Rider		(0.081)	(45.65)	(0.081)	(45.65)	0.00	
RSAM Rider		0.095	53.54	0.095	53.54	0.00	
			1,169.12		1,276.25	107.13	9.2%
Gas Supply Charge		5.617	3,165.46	5.617	3,165.46	(0.00)	
GCVA Rider		(0.787)	(443.51)	(0.787)	(443.51)	0.00	
			2,721.95		2,721.95	0.00	0.0%
Carbon Tax		0.745	419.84	0.745	419.84	(0.00)	
		\$7.650 /GJ	\$4,310.91	\$7.840 /GJ	\$4,418.04	107.13	2.5%
Permanent Rates Effective Jan. 1, 2009 compared to Proposed Rates Jan. 1, 2010							
		\$10.069 /GJ	\$5,674.61	\$7.840 /GJ	\$4,418.04	(\$1,256.57)	-22.1%

Note: This bill comparison is the average of the uses per account and rates that apply to each of the Fort St. John and Dawson Creek delivery areas.

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek 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 (RS1)	1 662 146	5,212,660	466,257	0.281
Commercial				
Small Commercial (RS2)	1 296 354	2,769,641	247,736	0.191
Large Commercial Firm (RS3)	305 100	492,205	44,026	0.144
Commercial Transportation (RS23)	66 500	119,473	10,686	0.161
Small Industrial Sales (RS4)	189 007	219,588	19,641	0.104
Industrial Transport				
RS6	616 998	693,941	62,071	0.1006
RS7		0	0 n.a.	
RS9	70 000	140,469	12,565	0.1795
RS10	326 656	308,751	27,617	0.0845
RS11	100 000	65,640	5,871	0.0587
TOTAL	4 632 761	10 022 367	896,471	

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

SUMMARY OF REVENUE, COST OF GAS, GROSS MARGIN

Customer Classification	2010 Test Year Gas Deliveries	Revenue	Cost of Gas	Gross Margin
	(GJ)	(\$)	(\$)	(\$)
Residential (RS1)	1 662 146	15 457 810	10 245 150	5,212,660
Commercial				
Small Commercial (RS2)	1 296 354	10 764 612	7 994 972	2,769,641
Large Commercial Firm (RS3)	305 100	2 362 706	1 870 501	492,205
Commercial Transportation (RS23)	66 500	119 473	0	119,473
Small Industrial Sales (RS4)	189 007	1 374 999	1 155 411	219,588
Industrial Transport				
RS6	616 998	693 941	0	693,941
RS7	0	0	0	0
RS9	70 000	140 469	0	140,469
RS10	326 656	308 751	0	308,751
RS11	100 000	65 640	0	65,640
TOTAL	4 632 761	31 288 401	21 266 034	10 022 367

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John / Dawson Creek Division)

Derivation of Test Year Forecast Gas Deliveries
 FORT ST. JOHN

Customer Classification	Estimated Customer Count At Dec. 31st, 2009	Test Year Effective Customer Additions	Test Year Weighted Average Customer Count	Test Year Average Use Per Account (GJ)	2010 Test Year Deliveries (GJ)
Residential (Rate 1)	9,079	58	9,137	115.1	1,051,701
Commercial					
Small Commercial Sales (Rate 2)	1,546	6	1,552	533.9	828,528
Large Commercial Firm Sales (Rate 3)					161,600
Commercial Transportation (RS23)					31,500
Small Industrial Sales (RS4)					134,999
Industrial Transportation					
RS6					616,998
RS7					
RS9					70,000
RS10					326,656
RS11					100,000
Total					3,321,982

DAWSON CREEK

Customer Classification	Customer Count At Dec. 31st, 2009	Test Year Effective Customer Additions	Test Year Weighted Average Customer Count	Test Year Average Use Per Account (GJ)	2010 Test Year Deliveries (GJ)
Residential (Rate 1)	5,382	96	5,478	111.4	610,445
Commercial					
Small Commercial Sales (Rate 2)	778	10	788	593.2	467,826
Large Commercial Firm Sales (Rate 3)					143,500
Commercial Transportation (RS23)					35,000
Small Industrial Sales (RS4)					54,008
Total					1,310,779

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)
 Summary of Test Year Gas Sales Supporting Schedule

Customer Classification	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)
Residential (Rate 1)	14,461	154	14,615	113.7	1,662,146
Commercial					
Small Commercial Sales (Rate 2)	2,324	16	2,340	554.0	1,296,354
Large Commercial Firm Sales (Rate 3)					305,100
Commercial Transportation (RS23)					66,500
Small Industrial Sales (RS4)					189,007
Industrial Transportation					
RS6					616,998
RS7					0
RS9					70,000
RS10					326,656
RS11					100,000
Total					4,632,761

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John / Dawson Creek Division)

Derivation of Test Year Forecast Gross Margin

Fort St. John	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
Residential (Rate 1)	1,051,701	2.470	2,597,701	9,137 *	7.00	767,508	3,365,209	3,365,209
Commercial								
Small Commercial Sales (Rate 2)	828,528	2.179	1,805,363	1,552	7.00	130,368	1,935,731	1,935,731
Large Commercial Sales (Rate 3)	161,600	1.682	271,811	17	150.00	30,600	302,411	302,411
Commercial Transport (Rate 23)	31,500	1.679	52,889	11	125.00	16,500	69,389	69,389
Small Industrial Sales (Rate 4)	134,999	0.851	114,884	5	410.00	24,600	139,484	139,484
Industrial Transportation								
Rate 6	616,998	1.0376	640,197	11	410.00	54,120	694,317	694,317
Rate 7			0	0		0	0	0
Rate 9	70,000	0.5415	37,905	1	8,547.04	102,564	140,469	140,469
Rate 10	326,656	0.2630	85,911	6	3,095.00	222,840	308,751	308,751
Rate 11	100,000	0.2850	28,500	1	3,095.00	37,140	65,640	65,640
Total Fort St. John	3,321,982		5,635,160			1,386,240	7,021,401	7,021,401

Dawson Creek	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
Residential (Rate 1)	610,445	2.272	1,386,931	5,478	7.00	460,152	1,847,083	1,847,083
Commercial								
Small Commercial Sales (Rate 2)	467,826	1.642	768,170	788	7.00	66,192	834,362	834,362
Large Commercial Sales (Rate 3)	143,500	1.134	162,729	15	150.00	27,000	189,729	189,729
Commercial Transport (Rate 23)	35,000	1.131	39,585	7	125.00	10,500	50,085	50,085
Small Industrial Sales (Rate 4)	54,008	1.119	60,435	4	410.00	19,680	80,115	80,115
Total Dawson Creek	1,310,779		2,417,850			583,524	3,001,374	3,001,374

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John / Dawson Creek Division)

Derivation of Test Year Forecast Gross Margin

FSJ / DC Combined	2010	Current		Weighted			Total	
Customer Classification	Test Year	Delivery	Delivery	Avg.	Current	Fixed Charge	Delivery	Test Year
	Gas Sales	Charge	Margin	Customer	Fixed Charge	Margin	& Fixed Charge	Gross
	(GJ)	\$ / GJ		Count			Margin	Margin
Residential (Rate 1)	1,662,146		3,984,633	14,615	7.00	1,227,660	5,212,293	5,212,293
Commercial								
Small Commercial Sales (Rate 2)	1,296,354		2,573,533	2,340	7.00	196,560	2,770,093	2,770,093
Large Commercial Sales (Rate 3)	305,100		434,540	32	150.00	57,600	492,140	492,140
Commercial Transport (Rate 23)	66,500		92,474	18	125.00	27,000	119,474	119,474
Small Industrial Sales (Rate 4)	189,007		175,319	9	410.00	44,280	219,599	219,599
Industrial Transportation								
Rate 6	616,998	0.9436	640,197	11	410.00	54,120	694,317	694,317
Rate 7	0	0.1977	0	0	0.00	0	0	0
Rate 9	70,000	0.4485	37,905	1	8,547.04	102,564	140,469	140,469
Rate 10	326,656	0.1700	85,911	6	3,095.00	222,840	308,751	308,751
Rate 11	100,000	0.1920	28,500	1	3,095.00	37,140	65,640	65,640
Total Fort St. John / Dawson Creek	4,632,761		8,053,011			1,969,764	10,022,775	10,022,775

**Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John / Dawson Creek Division)**

Derivation of Test Year Forecast Gas Supply Cost

<u>Fort St. John</u>	2010		
Customer Classification	Test Year Deliveries (GJ)	Gas Cost Charge (\$ / GJ)	Total Gas Cost (\$)
Residential (Rate 1)	1,051,701	6.164	6,482,685
Commercial			
Small Commercial Sales (Rate 2)	828,528	6.167	5,109,532
Large Commercial Sales (Rate 3)	161,600	6.131	990,770
Small Industrial Sales (Rate 4)	134,999	6.113	825,249
Total Fort St. John	2,176,828		13,408,236

<u>Dawson Creek</u>	2010		
Customer Classification	Test Year Deliveries (GJ)	Gas Cost Charge (\$ / GJ)	Total Gas Cost (\$)
Residential (Rate 1)	610,445	6.164	3,762,783
Commercial			
Small Commercial Sales (Rate 2)	467,826	6.167	2,885,083
Large Commercial Sales (Rate 3)	143,500	6.131	879,799
Small Industrial Sales (Rate 4)	54,008	6.113	330,151
Total Dawson Creek	1,275,779		7,857,815

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John / Dawson Creek Division)

Derivation of Test Year Forecast Gas Supply Cost

<u>FSJ / DC Combined</u>	2010		
Customer Classification	Test Year Deliveries (GJ)	Gas Cost Charge (\$ / GJ)	Total Gas Cost (\$)
Residential (Rate 1)	1,662,146	6.164	10,245,468
Commercial			
Small Commercial Sales (Rate 2)	1,296,354	6.167	7,994,615
Large Commercial Sales (Rate 3)	305,100	6.131	1,870,568
Small Industrial Sales (Rate 4)	189,007	6.113	1,155,400
Total Fort St. John / Dawson Creek	3,452,607		21,266,051

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Determination of Indicative 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 Indicative Rates Effective January 1, 2010				Indicative Gas Supply Cost Rate Changes Effective January 1, 2010			
	Demand (\$/GJ)	Commodity (\$/GJ)	Total D&C	Company Use Gas (\$/GJ)	Demand (\$/GJ)	Commodity (\$/GJ)	Total D&C	Company Use Gas (\$/GJ)	Demand (\$/GJ)	Commodity (\$/GJ)	Total D&C	Company Use Gas (\$/GJ)
Residential (RS1)	0.046	5.577	5.623	0.094	0.054	6.110	6.164	0.093	0.008	0.533	0.541	(0.001)
Small Commercial (RS2)	0.044	5.573	5.617	0.094	0.051	6.116	6.167	0.093	0.007	0.543	0.550	(0.001)
Large Commercial (RS3)	0.045	5.544	5.589	0.094	0.052	6.079	6.131	0.093	0.007	0.535	0.542	(0.001)
Small Industrial (RS4)	0.018	5.537	5.555	0.094	0.020	6.093	6.113	0.093	0.002	0.556	0.558	(0.001)
Company Use				0.094				0.093				(0.001)
Transportation Service				0.094				0.093				(0.001)

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

ALLOCATION OF DEMAND CHARGES EFFECTIVE JANUARY 1, 2010

Customer Classification	Peak Day Requirement		Allocation of Demand Charges (\$)	2010 Annual Requirements (GJ)	Unit Demand Charge (\$/GJ)
	(GJ)	(%)			
Residential (RS1)	17 354	50.47%	89,443	1 662 146	0.054
Small Commercial (RS2)	12 898	37.51%	66,481	1 296 354	0.051
Large Commercial (RS3)	3 065	8.91%	15,799	305 100	0.052
Industrial Sales (RS4)	735	2.14%	3,789	189 007	0.020
Company Use Gas	333	0.97%	1,717	67 400	0.025
Total	34 386	100.0%	177,228	3 520 007	

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

Determination of Indicative 2010 Unit Company Use Gas Cost Rate

Using September 28, 2009 Forward Gas Strip	
Demand Cost	\$1,717
Commodity Cost	\$410,443
B.C.S.S. Tax	\$4,068
Ice Levy	\$233
Carbon Tax	<u>\$13,021</u>
	<u><u>\$429,482</u></u>
Total Company use gas requirement	67 400 GJ
Deliveries	4 632 761 GJ
2009 Unit Company Use Gas Cost Rate	
\$0.093 /GJ	\$429,482
	4 632 761
Commodity Cost of Company Use Gas per GJ Purchased	
\$6.090 /GJ	\$410,443
	67 400

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

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

	Residential	Small Commercial	Total
Actual RSAM Balance at Year-end 2008	\$458,353	\$179,842	\$638,195
Estimated RSAM Recovery / Deferral in 2009	(\$315,035)	(\$178,871)	(\$493,906)
Estimated RSAM Balance at Year-end 2009	\$143,318	\$971	\$144,289
Years of Amortization			3
RSAM Balance divided by 3 Equals Amortization			\$48,096
Forecast 2010 Deliveries	1,662,145	1,296,352	2,958,498
One Year of Amortization divided by 2010 Deliveries equals RSAM Rate Rider (\$/GJ)			0.016

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

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.
(Fort St. John/Dawson Creek Division)**

UTILITY INCOME & RETURN

**SCHEDULE 1
(000's)**

Line No.		Test Year 2010	NSP 2009
1	Energy sales (TJ)	3 453	3 526
2	Average rate per GJ	\$8.90	\$10.39
3			
4	Transportation service (TJ)	1 180	1 211
5	Average rate per GJ	\$1.23	\$1.06
6			
7	Total deliveries (TJ)	4 633	4 737
8			
9	Utility revenue		
10	Energy sales	\$29,960	\$36,858
11	Interim rates - sales	778	(202)
12	Transportation service	1,328	1,312
13	Interim rates - transportation	119	(29)
14			
15		32,185	37,939
16	Cost of sales	21,266	27,790
17			
18	Gross margin	10,919	10,149
19			
20	Operating expenses	4,113	4,128
21	Maintenance expenses	283	223
22	Admin. & general expenses	1,362	1,329
23	Property taxes	1,052	977
24	Depreciation	1,522	1,430
25	Amortization	19	(43)
26	Investment income, other revenue	(196)	(187)
27	NSP Settlement Allowance for Shared Services	-	(23)
28			
29		8,154	7,834
30			
31	Earned return before income taxes	2,764	2,315
32	Income taxes	376	283
33			
34	Earned return	\$2,388	\$2,032
35			
36	Utility rate base	\$38,560	\$36,360
37			
38	Return on rate base	6.19%	5.59%

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek 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	\$1,561	\$1,490
3	- gas	430	542
4	- transferred to capital	(248)	(207)
5	- other	2,371	2,303
6	Total Operating	4,113	4,128
7	MAINTENANCE EXPENSES		
8	- wages	88	71
9	- other	195	152
10	Total Maintenance	283	223
11	ADMINISTRATIVE AND GENERAL EXPENSES		
12	- wages	-	-
13	- benefits	475	441
14	- transferred to capital	(258)	(208)
15	- other	1,146	1,096
16	Total Admin & General	1,362	1,329
17	TOTAL EXPENSES	\$5,758	\$5,680

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

OPERATING EXPENSES

(000's)

Line No.	Account and Description	Test Year 2010	NSP 2009
1	664 Communications	\$13	\$9
2	665 Pipelines	110	83
3	Pipelines - Gas	430	542
4	667 Regulating stations	114	111
5	Regulating stations - Gas	-	-
6	Total transmission	666	745
7	670 Supervision	453	441
10	673 Removing & resetting meters	257	235
11	674 Service on customer premises	43	37
12	675 Mains and services	338	309
13	677 Regulating stations	19	15
14	679 Other	-	-
15	Total distribution	1,109	1,037
16	684 Communications	1	1
17	685 General systems operations	198	189
	Shared Services from Parent	467	446
18	688 Other general operations	549	527
18	689 Transferred to capital	(248)	(207)
19	Total general	967	955
20	700 Sales supervision	13	13
21	701 Advertising	-	5
22	702 Demonstration and selling	2	2
23	709 Other	2	2
24	Total sales	17	22
25	711 Customer contracts	1	1
	Shared Services from Parent	190	151
26	712 Meter reading	202	187
27	713 Customer billing	441	451
	Shared Services from Parent	308	328
28	714 Credit and collections	19	18
	Shared Services from Parent	74	76
29	718 Uncollectible accounts	119	159
30	Total customer accounting	1,354	1,369
31	Total operating	\$4,113	\$4,128

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

MAINTENANCE EXPENSES

(000's)

Line No.	Account and Description	Test Year 2010	NSP 2009
1	864 Communications	\$0	\$0
2	865 Pipe lines	31	22
3	866 Compressors	-	-
4	867 Regulating stations	44	39
5	Total transmission	75	60
6	872 Structures	3	3
7	875 Mains and services	137	102
8	877 Regulating stations	10	10
9	878 Meters	57	47
10	879 Other	-	-
11	Total distribution	207	162
12	884 Communications	-	-
13	885 General	-	-
14	Total general	-	-
15	Total maintenance	\$283	\$223

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

ADMINISTRATIVE AND GENERAL EXPENSES

(000's)

Line No.	Account and Description	Test Year 2010	NSP 2009
1	721 Administration	\$3	\$2
2	Shared Services from Parent	782	726
3	722 Audit, legal & consulting fees	76	77
4	723 Insurance	123	144
5	724 Reserve for damages	-	-
6	725 Employee benefits	475	441
7	728 Shared Services from Parent	118	105
8	Regulation	38	37
9	Donations	5	5
10	Other	-	-
11	729 Transferred to capital	<u>(258)</u>	<u>(208)</u>
12	Total general and administrative	<u>\$1,362</u>	<u>\$1,329</u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

TAXES OTHER THAN INCOME TAXES

(000's)

Line No.	Account and Description	Test Year 2010	NSP 2009
1	PROPERTY TAXES		
2	Regular	\$809	\$755
3	1% in lieu	243	223
4	TOTAL	<u>\$1,052</u>	<u>\$977</u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

MISCELLANEOUS OPERATING REVENUE

(000's)

Line No.	Description	Test Year 2010	NSP 2009
1	Penalty charges	\$116	\$116
2	Connection Fees	24	24
3	Rents	-	-
4	Overheads recovered	37	37
5	Automotive surcharges	4	4
6	Other	<u>15</u>	<u>6</u>
7		<u>\$196</u>	<u>\$187</u>

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

UTILITY RATE BASE

SCHEDULE 2
 (000's)

Line No.		Test Year 2010	NSP 2009
1	Plant in service beginning of year	\$71,052	\$65,701
2	Additions	3,049	2,818
3	Disposals	(20)	(15)
4			
5	Plant in service end of year	74,081	68,504
6	Accumulated depreciation	27,959	26,132
7			
8	Net plant in service end of year	46,122	42,372
9			
10	Net plant beginning of year	44,970	41,319
11			
12	Net plant in service midyear	45,546	41,846
14	Contributions for construction	(8,247)	(7,179)
15	Unamortized deferred charges	153	402
16	Deferred income taxes	(553)	(553)
17	Reserve for damages	(69)	(69)
18	Cash working capital	1,531	1,703
19	Other working capital	199	210
20			
21	Utility rate base, midyear	\$38,560	\$36,360

Fort St. John / Dawson Creek Division

GAS PLANT IN SERVICE - 2009

(\$ 000's)

Line	Description	Actual 2009	Forecast			Forecast	
		Beginning Balance	Additions (incl O/H)	Allocations	Transfers	Retirements	2009 Ending Balance
1	Transmission plant						
2	460 Land	11				11	
3	461 Land rights	81				81	
4	462 Compressor structures	465				465	
5	463 Regulating structures	146				146	
6	465 Mains	6,203				6,203	
7	466 Compressor equipment						
8	467 Regulating equipment	3,614	262	49		3,924	
9	468 Communications	130				130	
10	469 Other	18				18	
11		10,668	262	49		10,979	
12	Distribution plant						
13	470 Land	37				37	
14	471 Land rights	222				222	
15	472 Structures	1,224	183	32		1,439	
16	473 Services	15,723	357	61		16,141	
17	474 House installations	4,580	92	16		4,688	
18	475 Mains	23,933	3,527	398		27,858	
19	476 Compressor equipment						
20	477 Regulating equipment	1,379	71			1,450	
21	478 Meters	1,937	99			2,036	
22	479 Other	20				20	
23		49,055	4,330	507		53,892	
24	General plant						
25	480 Land	77				77	
26	481 Land rights	1				1	
27	482 Structures	1,289				1,289	
28	483 Office equipment	286	5			291	
29	484 Transportation equipment	1,079	29		(136)	972	
30	485 Heavy work equipment	890	219			1,109	
31	486 Tools	1,099	77			1,176	
32	487 Computer equipment	960				960	
33	488 Communications	299	11			309	
38	489 Other	(4)				(4)	
39		5,977	340			(136)	6,181
40	Construction overheads						
41	Unallocated construction costs		45	(45)			
42	System operations transfers		216	(216)			
43	Administrative transfers		207	(207)			
44	Depreciation		88	(88)			
45			556	(556)			
46		65,701	5,488			(136)	71,052

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

GAS PLANT IN SERVICE - TEST YEAR 2010

Line	Description	(\$ 000's)				Forecast
		Forecast	Forecast			Ending
		Balance	Additions	Allocations	Retirements	Balance
1	Transmission plant					
2	460 Land	11				11
3	461 Land rights	81				81
4	462 Compressor structures	465				465
5	463 Regulating structures	146				146
6	465 Mains	6,203	196	59		6,458
7	466 Compressor equipment					-
8	467 Regulating equipment	3,924	207	48		4,180
9	468 Communications	130				130
10	469 Other	18				18
		<hr/>				
11		10,979	403	107		11,489
12	Distribution plant					
13	470 Land	37				37
14	471 Land rights	222				222
15	472 Structures	1,439	166	52		1,658
16	473 Services	16,141	545	198		16,884
17	474 House installations	4,688	106	35		4,830
18	475 Mains	27,858	835	245		28,939
19	476 Compressor equipment	0				0
20	477 Regulating equipment	1,450	66	-		1,516
21	478 Meters	2,036	122			2,158
22	479 Other	20				20
		<hr/>				
23		53,892	1,841	530		56,262
24	General plant					
25	480 Land	77				77
26	481 Land rights	1				1
27	482 Structures	1,289				1,289
28	483 Office equipment	291	5			296
29	484 Transportation equipment	972	41		(20)	993
30	485 Heavy work equipment	1,109	40			1,149
31	486 Tools	1,176	83			1,258
32	487 Computer equipment	960				960
33	488 Communications	309				309
38	489 Other	(4)				(4)
		<hr/>				
39		6,181	168		(20)	6,329
40	Construction overheads					
41	Unallocated construction costs		35	(35)		
42	System operations transfers		248	(248)		
43	Administrative transfers		258	(258)		
44	Depreciation		95	(95)		
		<hr/>				
45			637	(637)		
46		<hr/>	<hr/>	<hr/>	<hr/>	<hr/>
		71,052	3,049	(0)	(20)	74,081

Pacific Northern Gas (NE) Ltd.
 Fort St. John / Dawson Creek

GAS PLANT IN SERVICE - CONTINUITY OF PLANT COST

		(000's)	
		Test Year	Forecast
<u>Line</u>	<u>Description</u>	<u>2010</u>	<u>2009</u>
1	Balance, Beginning of Year	71,052	65,701
2	CIAC Balance, Beginning of Year	(12,920)	(11,655)
3	Plant Cost, net of CIAC, Beginning of Year	<u>58,132</u>	<u>54,045</u>
4	Additions during year:		
5	Plant Cost	2,412	5,488
6	Allocation of overheads	637	()
7	Total Plant Additions	<u>3,049</u>	<u>5,488</u>
8	Contributions in Aid of Construction	(439)	(1,265)
9	Total Additions	<u>2,610</u>	<u>4,223</u>
10	Plant Retirements:		
11	Normal Course	(20)	(136)
12	Deactivated Assets	-	-
13	CIAC Retirements	-	-
14	Total Retirements	<u>(20)</u>	<u>(136)</u>
15	Balance, End of Year	<u>60,722</u>	<u>58,132</u>
16	Closing balance consists of:		
17	Plant Cost	74,081	71,052
18	CIAC	<u>(13,359)</u>	<u>(12,920)</u>
19	Balance, End of Year	<u>60,722</u>	<u>58,132</u>

Fort St. John / Dawson Creek Division

CONTINUITY OF
 ACCUMULATED DEPRECIATION

FOR THE YEAR 2009

(\$ 000's)

Line	Description	Rate	Forecast					'09 Ending Balance
			Actual 2009 Beginning Balance	Provision	Transfers	Retirements	Recoveries	
1	Gathering Plant							
2	Franchises & Consents	1.00%	(0)					(0)
3	Gas Holders - Manufacturing	1.00%	(9)					(9)
4	Gas Holders - Storage		(4)					(4)
5								
6			(13)					(13)
7	Transmission plant							
8	461 Land rights	3.59%	(53)	(3)				(56)
9	462 Compressor structures	3.00%	(143)	(14)				(157)
10	463 Regulating structures	2.93%	(39)	(4)				(44)
11	465 Mains	2.79%	(3,433)	(173)				(3,606)
12	466 Compressor equipment	N/A						
13	467 Regulating equipment	3.40%	(1,421)	(123)				(1,544)
14	468 Communications	5.00%	(92)	(6)				(98)
15	469 Other	3.00%	(3)	(1)				(4)
16								
17			(5,184)	(324)				(5,508)
18	Distribution plant							
19	471 Land Rights	0.72%	(19)	(2)				(20)
20	472 Structures	2.99%	(269)	(37)				(306)
21	473 Services	2.04%	(3,633)	(320)				(3,954)
22	474 House installations	2.82%	(1,753)	(129)				(1,883)
23	475 Mains	2.43%	(8,803)	(581)				(9,384)
24	476 Compressor equipment	0.00%	(0)	(0)				(0)
25	477 Regulating equipment	2.89%	(841)	(40)				(881)
26	478 Meters	3.00%	(503)	(58)				(561)
27	479 Other	3.00%	(6)	(1)				(6)
28								
29			(15,828)	(1,168)				(16,996)
30								
31	General plant							
32	481 Land Rights		(0)	(0)				(0)
33	482 Structures	2.95%	(629)	(38)				(667)
34	483 Office equipment	1.84%	(237)	(5)				(242)
35	484 Transportation equipment	12.26%	(759)	(132)		136	(41)	(797)
36	485 Heavy work equipment	4.68%	(277)	(42)				(319)
37	486 Tools	4.26%	(550)	(47)				(597)
38	487 Computer equipment	2.93%	(709)	(28)				(738)
39	488 Communications	4.02%	(197)	(12)				(209)
40	489 Other	3.00%	(3)					(3)
41			(3,356)	(304)		136	(41)	(3,566)
42								
43			(24,381)	(1,796)		136	(41)	(26,082)
44								
45	Amortization of CIAC			244				
46								
47	Depreciation capitalized			88				
48								
49	Net Depreciation Expense			(1,464)				

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

CONTINUITY OF
 ACCUMULATED DEPRECIATION

TEST YEAR 2010

(\$ 000's)

Line	Description	Rate	Balance	Forecast			Forecast '10 Ending Balance
				Provision	Retirements	Recoveries	
1	Gathering Plant						
2	Franchises & Consents	1.00%	(0)				(0)
3	Gas Holders - Manufacturing	1.00%	(9)				(9)
4	Gas Holders - Storage		(4)				(4)
5							
6			(13)				(13)
7	Transmission plant						
8	461 Land rights	3.59%	(56)	(3)			(59)
9	462 Compressor structures	3.00%	(157)	(14)			(171)
10	463 Regulating structures	3.00%	(44)	(4)			(48)
11	465 Mains	2.79%	(3,606)	(173)			(3,779)
12	466 Compressor equipment	N/A					
13	467 Regulating equipment	3.44%	(1,544)	(135)			(1,678)
14	468 Communications	3.36%	(98)	(4)			(103)
15	469 Other	3.00%	(4)	(1)			(4)
16							
17			(5,508)	(334)			(5,842)
18	Distribution plant						
19	471 Land Rights	0.72%	(20)	(2)			(22)
20	472 Structures	2.99%	(306)	(43)			(349)
21	473 Services	2.04%	(3,954)	(329)			(4,282)
22	474 House installations	2.80%	(1,883)	(131)			(2,014)
23	475 Mains	2.39%	(9,384)	(664)			(10,049)
24	476 Compressor equipment	3.00%	(0)	(0)			(0)
25	477 Regulating equipment	2.90%	(881)	(42)			(923)
26	478 Meters	3.00%	(561)	(61)			(622)
27	479 Other	3.00%	(6)	(1)			(7)
28							
29			(16,996)	(1,273)			(18,268)
30							
31	General plant						
32	481 Land Rights		(0)	(0)			(0)
33	482 Structures	2.71%	(667)	(35)			(702)
34	483 Office equipment	1.31%	(242)	(4)			(246)
35	484 Transportation equipment	10.94%	(797)	(106)	20	(4)	(887)
36	485 Heavy work equipment	4.74%	(319)	(53)			(371)
37	486 Tools	4.20%	(597)	(49)			(646)
38	487 Computer equipment	2.93%	(738)	(28)			(766)
39	488 Communications	3.68%	(209)	(11)			(221)
40	489 Other	3.00%	3				3
41			(3,566)	(287)	20	(4)	(3,836)
42							
43			(26,082)	(1,893)	20	(4)	(27,959)
44							
45	Amortization of CIAC		26,056	276			
46							
47	Depreciation capitalized			95			
48							
49	Net Depreciation Expense			(1,522)			

Pacific Northern Gas (NE) Ltd.
 Fort St. John / Dawson Creek

GAS PLANT IN SERVICE - CONTINUITY OF ACCUMULATED DEPRECIATION

(000's)

<u>Line</u>	<u>Description</u>	Test Year <u>2010</u>	Forecast <u>2009</u>
1	Balance, Beginning of Year	(26,082)	(24,381)
2	CIAC Accumulated Balance, Beginning of Year	4,754	4,510
3	Utility Accumulated Depreciation, Beginning of Year	<u>(21,328)</u>	<u>(19,871)</u>
4	Depreciation Provision:		
5	Plant	(1,893)	(1,796)
6	Contributions in Aid of Construction	276	244
7	Depreciation Adjustment Deferral		
8	Total Additions	<u>(1,617)</u>	<u>(1,551)</u>
9	Plant Retirements:		
10	Normal Course	20	136
11	Deactivated Assets		
12	CIAC Retirements		
13	Removal Costs		
14	Proceeds on Disposals	(4)	(41)
15	Total Retirements	<u>16</u>	<u>95</u>
16	Balance, End of Year	<u><u>(22,929)</u></u>	<u><u>(21,328)</u></u>
17	Closing Balance Consists of:		
18	Accumulated Depreciation - Plant	(27,959)	(26,082)
19	Accumulated Amortization - CIAC	<u>5,030</u>	<u>4,754</u>
20	Balance, End of Year	<u><u>(22,929)</u></u>	<u><u>(21,328)</u></u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CONTINUITY OF DEFERRED CHARGES

		YEAR 2009				
		(000's)				
<u>Line</u>	<u>Description</u>	<u>Actual</u>				
		<u>Balance '08</u>	<u>Additions</u>	<u>Tax</u>	<u>Amortization</u>	<u>Balance '09</u>
1	Rate base items					
2	Property tax variance	24	12	(4)	24	8
3	BCUC Hearing costs & CAP/ROE	(8)	19	(6)	1	5
4	Contribution to WEI Taylor	0	0	0	0	0
5	Studies	0	0	0	0	0
6	RSAM	440	(494)	148	0	95
7	DC Industrial Deliveries	8	23	(7)	4	20
8	Resource Plans	13	0	0	0	13
9	Bill 198 Compliance Costs	17	0	0	9	9
10	IFRS	3	21	(6)	0	18
11		499	(419)	126	38	168
12						
13	Average rate base for the year					<u>\$333</u>
14						
15	Interest bearing deferrals					
16	BCUC Fees	(6)	(15)	5	(6)	(11)
17	Short Term Interest Rate	(43)	20	(6)	(10)	(18)
18	Long Term Interest Rate	(124)	(21)	6	(62)	(77)
19	Depreciation Adjustment	(0)	-	-	(0)	(0)
20	Carbon / Income Tax	(3)	-	-	(3)	0
21	GCVA	(1,493)	(1,187)	346	0	(2,334)
22						
23		(1,668)	(1,204)	351	(81)	(2,440)
24						
25	Total deferrals (excl. debt issue)	(\$1,170)	(\$1,623)	\$476	(\$44)	(\$2,273)
26						
27						
28	Debt Issue Costs	433	0	0	81	\$352

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CONTINUITY OF DEFERRED CHARGES

TEST YEAR 2010						
(000's)						
<u>Line</u>	<u>Description</u>	<u>Forecast</u>				<u>Balance '10</u>
		<u>Balance '09</u>	<u>Additions</u>	<u>Tax</u>	<u>Amortization</u>	
1	Rate base items					
2	Property tax variance	8	0	0	8	(0)
3	BCUC Hearing costs & CAP/ROE	5	36	(10)	8	23
4	Contribution to WEI Taylor	0	0	0	0	0
5	Studies	0	0	0	0	0
6	RSAM	95	(42)	12	0	65
7	DC Industrial Deliveries	20	0	0	10	10
8	Resource Plans	13	0	0	13	0
9	Bill 198 Compliance Costs	9	0	0	9	(0)
10	IFRS	18	32	(9)	0	41
11		168	25	(7)	48	138
12						
13	Average rate base for the year					<u>\$153</u>
14						
15	Interest bearing deferrals					
16	BCUC Fees	(11)	(0)	0	(11)	(0)
17	Short Term Interest Rate deferral	(18)	40	(12)	20	(10)
18	Long Term Interest Rate deferral	(77)	(3)	0	(39)	(42)
19	Depreciation Adjustment	(0)	-	0	-	(0)
20	Carbon / Income Tax	0	-	0	0	0
21	GCVA	(2,334)	2,509	(740)	0	(565)
22						
23		(2,440)	2,546	(752)	(29)	(617)
24						
25	Total deferrals (excl. debt issue)	(\$2,273)	\$2,571	(\$759)	\$19	(\$479)
26						
27						
28	Debt Issue Costs	\$352	\$0	\$0	\$78	\$275

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CASH WORKING CAPITAL

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

Line No.	Description	Lag /(Lead) Days	<u>Expense</u>	<u>Working Capital</u>
1	Revenue	58.3		
2	Expense		<u>(39.5)</u>	
3	Operating working capital	18.8	29,142	\$1,497
4	Adjustments:			
5	Budget Billing Plan			(\$178)
6	PST, ICEF Levy & Carbon Tax			\$38
7	GST/HST			<u>\$175</u>
8	Cash working capital			<u><u>\$1,531</u></u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

REVENUE LAG DAYS

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

Line No.	Revenues	Revenue Lag Days	Revenue	Extended Revenue
1	Residential - monthly	47.4	\$4,940	\$234,045
2	- bimonthly	63.7	10,518	670,370
3				
4	Small commercial - monthly	60.5	1,422	85,943
5	- bimonthly	63.7	9,343	594,792
6				
7	Large commercial - firm	45.9	2,482	113,927
8				
9	Small industrial	48.2	2,584	124,453
10				
11	Revenue Deficiency	58.3	896	52,248
12				
13	Other operating revenue	58.3	196	11,421
14				
15	Average revenue lag days	58.3	\$32,381	\$1,887,198

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

EXPENSE LEAD DAYS

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

Line No.	Expenses	Expense (Lead) Days	Normalized Expenses	Extended Expenses
1	Gas purchases-baseload	(40.2)	\$286	(\$11,498)
2	Gas purchases-seasonal	(40.2)	21,410	(860,663)
3	Operating payrolls	(5.0)	1,648	(8,242)
4	Employee benefits	(20.9)	475	(9,923)
5	Uncollectible accounts	(59.3)	119	(7,051)
6	Other operating expenses	(31.4)	3,469	(108,928)
7	Expenses credited/capitalized	(10.6)	(506)	5,338
8	Insurance	182.5	123	22,535
9	Property taxes	(1.0)	1,052	(1,052)
10	Franchise Fees	(242.5)	687	(166,709)
11	Income taxes payable	(15.2)	379	(5,760)
12	Average expense lag days	<u>(39.5)</u>	<u>\$29,142</u>	<u>(\$1,151,952)</u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CASH WORKING CAPITAL - GOODS AND SERVICES TAX

FOR THE 6 MONTH PERIOD ENDED JUNE 30, 2010

(\$000's)

Line No.	Description	Taxable Amount	GST @ 5%	Receipt Lag Days	Payment (Lead) Days	Net Lag/(Lead)	Working Capital
1	Revenues						
2	Residential and commercial	\$16,610	\$831	19.6	(30.4)	(10.8)	(24.6)
3	Industrial - FSJ	1,147	57	30.8	(47.6)	(16.8)	(2.6)
4	Industrial - DC	234	12	39.0	(60.8)	(21.8)	(0.7)
5	Franchise fee	469	23	20.4	(31.9)	(11.4)	(0.7)
6	Carbon Tax	1,447	72	20.4	(30.8)	(10.4)	(2.1)
7							
8		<u>\$19,907</u>	<u>\$995</u>			<u>(11.3)</u>	<u>(\$30.7)</u>
9							
10							
11				Recovery	Payment	Net	Working
12				<u>Lag Days</u>	<u>(Lead) Days</u>	<u>Lag/(Lead)</u>	Capital
13	Purchases						
14	Capital expenditures	\$842	\$42	30.4	8.2	38.6	4.5
15	Gas supply	11,648	582	60.8	(25.0)	35.8	57.1
16	Operating costs	1,735	87	30.4	8.2	38.6	9.2
17							
18		<u>\$14,224</u>	<u>\$711</u>			<u>36.3</u>	<u>\$70.7</u>
19							
20							<u>\$40.1</u>

**Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)**

CASH WORKING CAPITAL - HST

**FOR THE PERIOD JULY 1, 2010 THRU DECEMBER 31, 2010
(\$000's)**

Line No.	Description	Taxable Amount	HST @ 12%*	Receipt Lag Days	Payment (Lead) Days	Net Lag/(Lead)	Working Capital
1	Revenues						
2	Residential	\$6,948	\$347	19.7	(30.4)	(10.7)	(10.2)
3	Commercial	6,016	722	28.5	(29.4)	(0.9)	(1.8)
4	Industrial - FSJ	1,133	136	30.8	(47.8)	(17.0)	(6.3)
5	Industrial - DC	214	26	39.0	(60.8)	(21.8)	(1.5)
6	Franchise fee	219	26	21.7	(34.3)	(5.9)	(0.4)
7	Carbon Tax	1,500	180	20.6	(30.9)	(10.3)	(5.1)
8							
9		<u>\$16,030</u>	<u>\$1,437</u>			<u>(6.4)</u>	<u>(\$25.4)</u>
10							
11							
12				Recovery	Payment	Net	Working
13				<u>Lag Days</u>	<u>(Lead) Days</u>	<u>Lag/(Lead)</u>	Capital
14	Purchases						
15	Capital expenditures	\$1,570	\$188	30.4	8.2	38.6	19.9
16	Gas supply	10,048	1,206	60.8	(25.0)	35.8	118.3
17	Operating costs	1,735	208	30.4	8.2	38.6	22.0
18							
19		<u>\$13,352</u>	<u>\$1,602</u>			<u>36.5</u>	<u>\$160.2</u>
20							
21							<u>\$134.8</u>
22	*Effective HST rate on residential sales revenue is 5% due to point of sale rebate of 7%.						

**Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)**

CASH WORKING CAPITAL - PROVINCIAL SALES TAX, ICEF LEVY & CARBON TAX

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

Line No.	Description	Taxable <u>Amount</u>	P.S.T. <u>@ 7%</u>	Receipt <u>Lag Days</u>	Payment <u>(Lead) Days</u>	Net <u>Lag/(Lead)</u>	Working <u>Capital</u>
1	Revenues						
2	Commercial sales	\$7,500	\$525	21.7	(23.0)	(1.3)	(1.8)
3	Industrial sales - FSJ	497	35	33.2	(23.0)	10.2	1.0
4	Industrial sales - DC	537	38	39.0	(53.4)	(14.4)	(1.5)
5	Franchise fees	222	16	23.5	(24.9)	(1.4)	(0.1)
6	PST Subtotal	<u>8,757</u>	<u>613</u>				<u>(2.4)</u>
7							
8			ICEF Levy				
9			<u>@ 0.4%</u>				
10	Residential sales	\$9,037	\$36	17.8	(23.0)	(5.2)	(0.5)
11	Commercial sales	7,500	30	21.7	(23.0)	(1.3)	(0.1)
12	Industrial sales - FSJ	497	2	33.2	(23.0)	10.2	0.1
13	Industrial sales - DC	537	2	39.0	(53.4)	(14.4)	(0.1)
14	Franchise fees	461	2	20.6	(23.9)	(3.4)	(0.0)
15	ICEF Levy Subtotal	<u>18,033</u>	<u>72</u>				<u>(0.7)</u>
16							
17		Taxable	Carbon				
18	Gas sales subject to Carbon Tax	<u>GJs</u>	<u>Tax</u>				
19	Residential sales - January to June	950 862	\$708	17.8	(15.0)	2.8	5.4
20	- July to December	711 284	706	17.8	(15.0)	2.8	5.3
21	Commercial sales - January to June	894 865	667	21.7	(15.0)	6.7	12.2
22	- July to December	706 589	702	21.6	(15.0)	6.6	12.8
23	FSJ Small Industrial sales - January to June	68 383	51	33.2	(15.0)	18.2	2.5
24	- July to December	66 616	66	33.2	(15.0)	18.2	3.3
25	DC Small Industrial sales - January to June	28 148	21	39.0	(45.4)	(6.4)	(0.4)
26	- July to December	25 860	26	39.0	(45.4)	(6.4)	(0.4)
27	Carbon Tax Subtotal	<u>3452 607</u>	<u>2,947</u>	20.5	(15.5)		40.7
28							
29	PST, ICEF Levy & Carbon Tax Total						<u>\$37.7</u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

OTHER WORKING CAPITAL ITEMS

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

Line No.	Description	Transmission Line Pack	Materials & Supplies	Total
1	MONTH END BALANCES			
2	January	0	\$130	\$130
3	February	0	195	195
4	March	0	193	193
5	April	0	195	195
6	May	0	195	195
7	June	0	193	193
8	July	0	213	213
9	August	0	225	225
10	September	0	219	219
11	October	0	230	230
12	November	0	196	196
13	December	0	202	202
14	Total	<u>\$0</u>	<u>\$2,385</u>	<u>\$2,385</u>
15	Average balance	<u>\$0</u>	<u>\$199</u>	<u>\$199</u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

CONTRIBUTIONS IN AID OF CONSTRUCTION

(000's)

Line No.	Description	Test Year 2010	NSP 2009
1	Gas Plant In Service		
2	Beginning balance	\$12,920	\$11,655
3	Additions	439	311
4	Ending balance	\$13,359	\$11,966
5	Accumulated Amortization		
6	Beginning balance	(\$4,754)	(\$4,510)
7	Additions	(276)	(244)
8	Ending balance	(\$5,030)	(\$4,754)
9	Net Total		
10	Beginning balance	\$8,166	\$7,145
11	Additions	163	67
12	Ending balance	\$8,328	\$7,212
13	Average balance	\$8,247	\$7,179

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

INCOME TAXES

SCHEDULE 3
(000's)

Line No.	Test Year 2010	NSP 2009
1	Calculation of Taxable Income	
2	\$2,764	\$2,315
3	(881)	(871)
4	15	13
5	(579)	(514)
6		
7	<u>\$1,320</u>	<u>\$943</u>
8		
9	Calculation of Income Tax Expense	
10	\$376	\$283
11	-	-
12	-	-
13		
14	<u>\$376</u>	<u>\$283</u>
15		
16	Particulars of Timing Differences	
17	A. Tax Effects Subject To Flowthrough	
18	\$1,522	\$1,430
19	19	(43)
20	(1,714)	(1,569)
21	-	-
22	(405)	(332)
23	-	-
24		
25		
26	<u>(\$579)</u>	<u>(\$514)</u>
27		
28	28.50%	30.00%
29	0.00%	0.00%
30	28.50%	30.00%

Pacific Northern Gas (N.E.) Ltd.
 (Fort St. John/Dawson Creek Division)

COMMON EQUITY

SCHEDULE 4
 (000's)

Line No.		Test Year 2010	NSP 2009
1	Opening balance		
2	Share capital	\$8,295	\$8,295
3	Contributed surplus	-	-
4	Retained earnings	5,807	4,691
5			
6		14,103	12,986
7			
8	Net income	1,515	1,161
9	Shares issued	1,750	-
10	Preferred dividends	-	-
11	Common dividends	(444)	(954)
12			
13	Closing balance	\$16,923	\$13,193
14			
15			
16	Midyear common equity	\$16,388	\$13,090

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

RETURN ON CAPITAL

SCHEDULE 5
(000's)

Line No.		Test Year 2010	NSP 2009
1	Short term borrowings	\$2,504	\$3,387
2	proportion	6.49%	9.32%
3	rate of return	3.23%	2.41%
4	return component	0.21%	0.22%
5			
6	Long term debt	\$19,668	\$19,883
7	proportion	51.01%	54.68%
8	rate of return	4.07%	3.97%
9	return component	2.07%	2.17%
10			
11	Preferred shares	\$0	\$0
12	proportion	0.00%	0.00%
13	rate of return	6.48%	6.48%
14	return component	0.00%	0.00%
15			
11	Common equity	\$16,388	\$13,089
12	proportion	42.50%	36.00%
13	rate of return	9.20%	8.87%
14	return component	3.91%	3.19%
15			
16	Total capitalization	<u>\$38,560</u>	<u>\$36,360</u>
17			
18	Return on rate base	<u>6.19%</u>	<u>5.59%</u>
19			
20	Utility rate base	<u>\$38,560</u>	<u>\$36,360</u>

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

SHORT TERM DEBT

FOR THE YEAR ENDED DECEMBER 31
(000's)

		Test Year 2010	NSP 2009
1	Customer Security Deposits		
2	Average annual balance	\$1,314	\$1,314
3	Interest rate applicable to deposits	1.21%	0.25%
4	Annual Interest Expense	\$16	\$3
5			
6	Operating Line / Other		
7	Average annual draw	\$1,190	\$2,073
8	Interest rate	5.46%	3.78%
9	Annual Interest Expense	\$65	\$78
10			
11	Average short term interest rate	3.23%	2.41%

Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek Division)

LONG TERM DEBT

FOR THE YEAR ENDED DECEMBER 31
(000's)

	Test Year 2010	NSP 2009
1 Secured Debentures Series 2018		
2 Liability beginning of year	\$1,524	\$1,592
3 Sinking fund payments	(68)	(68)
4 Average Capitalization	1,515	1,583
5 Annual Interest Expense	133	139
6 Issue costs beginning of year	(6)	(8)
7 Amortization of Issue Costs	1	1
8		
9 Effective Cost Rate	8.89%	8.89%
10		
11 Roynat 2017 Loan		
12 Liability beginning of year	\$11,000	\$11,000
13 Sinking fund payments	(293)	-
14 Average Capitalization	10,853	11,000
15 Annual Interest Expense	407	394
16 Issue costs beginning of year	299	359
17 Amortization of Issue Costs	58	61
18		
19 Effective Cost Rate	4.26%	4.14%
20		
21 2007 5-year Term Intercompany Loan		
22 Liability beginning of year	\$7,300	\$7,300
23 Issue during the year	-	-
24 Sinking fund payments	-	-
25 Average Capitalization	7,300	7,300
26 Annual Interest Expense	184	174
27 Issue costs beginning of year	47	66
28 Amortization of Issue Costs	18	19
29		
30 Effective Cost Rate	2.77%	2.64%
31		
32 Total Actual Debt		
33 Total Average Capitalization	19,668	19,883
34		
35 Effective Cost Rate	4.07%	3.97%



**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

**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** G-

2

- 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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