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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-100-06

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

and

Application by Pacific Northern Gas (N.E.) Ltd.
(Fort St. John/Dawson Creek and Tumbler Ridge Divisions)
for Approval of 2006 Rates

BEFORE: L.A. Boychuk, Panel Chair
and Commissioner

August 16, 2006

O R D E R

WHEREAS:

A. On November 30, 2005, Pacific Northern Gas (N.E.) Ltd. Fort St. John/Dawson Creek and Tumbler Ridge Divisions ["PNG (N.E.)"] filed for approval of its 2006 Revenue Requirements Application ("the Application"). PNG (N.E.) proposed to amend its rates on an interim and final basis, effective January 1, 2006, pursuant to Sections 89 and 58 of the Utilities Commission Act ("the Act"); and

B. The Application proposes to increase delivery rates to all customers primarily as a result of increases in the cost of service, including the cost of company use gas; and

C. On December 12, 2005 PNG (N.E.) filed its Fourth Quarter 2005 Report on gas supply costs and Gas Cost Variance Account ("GCVA") balances ("the Report"), and requested changes to Gas Supply Cost Recovery Rates for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions effective January 1, 2006 based on November 28, 2005 natural gas forward prices. PNG (N.E.) proposed that no changes be made to GCVA rate riders; and

D. The Report projected a debit balance of $1,516,000 in the Fort St. John/Dawson Creek GCVA at December 31, 2005, which would require an increase in the GCVA debit rate rider from $0.099/GJ to $0.434/GJ to repay the GCVA balance to PNG (N.E.) over 2006; and

E. The Report also projected a credit balance of $118,000 in the Tumbler Ridge GCVA at December 31, 2005, which the current GCVA credit rate rider of $0.350/GJ will repay to customers over approximately 2.4 years; and

F. PNG (N.E.) had discussions regarding the review process for the Application with the BC Old Age Pensioners Organization et al. ("BCOAPO") and staff of the Ministry of Energy, Mines and Petroleum Resources ("Ministry staff"), who were active intervenors in the review of the PNG 2005 revenue requirements application (the "Parties"). By letter dated December 13, 2005 PNG advised the Commission that the Parties were of the view that the Application should be subject to a Negotiated Settlement Process ("NSP"); and

G. Commission Order No. G-135-05 approved the interim refundable rate increase in the delivery charges for all rate classes of customers as filed in the Application, the permanent Gas Supply Cost Recovery Rates, the permanent Fort St. John/Dawson Creek Division debit GCVA rate rider and the continuation of the permanent Tumbler Ridge Division credit GCVA rate rider, all effective January 1, 2006; and

H. Commission Order No. G-135-05 also established an NSP for the review of the Application; and

I. The Negotiated Settlement discussions were held in Vancouver on March 13, 14 and 15, 2006 and a proposed Settlement Agreement regarding the Application was agreed to by PNG (N.E.) and the Intervenors; and

J. In a letter of comment submitted on March 29, 2006 regarding the PNG-West Division 2006 Revenue Requirements NSP, BCOAPO did not accept the proposed PNG-West Settlement Agreement. BCOAPO objected to Item 1 of the proposed PNG-West Settlement Agreement and claimed that its objection would fundamentally change the overall 2006 cost of service for PNG-West. Changes in the PNG-West 2006 cost of service may impact the allocation of shared costs from PNG-West to PNG (N.E.); and

K. The Commission received submissions on the proposed PNG-West Settlement Agreement and other filings by PNG-West and Intervenors; and

…/3

L. By Order No. G-99-06 with Reasons attached, the Commission issued its determination on the PNG-West 2006 Revenue Requirements Application; and

M. The Commission has reviewed the proposed Settlement Agreement for PNG (N.E.) and considers that approval is warranted.

NOW THEREFORE pursuant to sections 58, 60 and 61 of the Act, the Commission orders as follows:

1. The Commission approves for PNG (N.E.) the Negotiated Settlement Agreement attached as Appendix A, the Terms of the Negotiated Settlement Agreement along with the supporting schedules showing the effects of the changes arising from the Negotiated Settlement Agreement.

2. Since the approved rates are less than the interim rates which have been in effect since January 1, 2006, PNG (N.E.) is to inform its customers of the final rates by way of a customer notice and provide a method for refunding excess payments back to customers.

3. PNG (N.E.) is to file permanent Gas Tariff Rate Schedules that are in accordance with the terms of the Settlement and this Order.

4. PNG (N.E.) is to file a complete set of regulatory schedules in the form of the February 17, 2006 Update by September 8, 2006.

DATED at the City of Vancouver, in the Province of British Columbia, this 21st day of August 2006.

BY ORDER

Original signed by:

L.A. Boychuk
Panel Chair & Commissioner

Attachment

WILLIAM J. GRANT
TRANSITION ADVISOR,
REGULATORY AFFAIRS & PLANNING
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BRITISH COLUMBIA UTILITIES COMMISSION

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Log No. 12701

VIA E-MAIL

March 31, 2006

Registered Intervenors (PNGNE-2006RR-RI)
Pacific Northern Gas - 2006 Revenue Requirements

Dear Registered Intervenors:

Re: Pacific Northern Gas (N.E.) Ltd. ["PNG(N.E.)"]
Fort St. John/Dawson Creek and Tumbler Ridge Divisions
Negotiated Settlements
2006 Revenue Requirements Application

Enclosed with this letter is the proposed settlement package for PNG(N.E.)'s 2006 Revenue Requirements Application for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions.

This settlement package is now public and is being submitted to the Commission and all Intervenors. Also enclosed are Letters of Acceptance from the participants in the negotiated settlement process. The Letter of Acceptance from PNG (N.E.) explains the revised regulatory schedules that are attached to the settlement agreement.

Prior to consideration by the Commission, Intervenors who did not participate in the settlement negotiations will be requested to provide to the Commission with their comments on the settlement package by Thursday, April 6, 2006. Thereafter, the Commission will consider the settlement package. A public hearing may not be required unless there is significant opposition to the proposed settlements.

Yours truly,

William J. Grant

PWN/dlf
Attachments
cc: Mr. Craig Donohue
Director, Regulatory Affairs and Gas Supply
Pacific Northern Gas (N.E.) Ltd.

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

2006 Revenue Requirements Application

NEGOTIATED SETTLEMENT AGREEMENT

March 15, 2006

Introduction

PNG(N.E.) representatives, Commission Staff and registered intervenors met on March 13, 14 and 15, 2006 for the purpose of negotiating a settlement of PNG(N.E.)'s Tumbler Ridge division 2006 revenue requirements application. For ease of reference PNG(N.E.) will be referred to in this settlement agreement as PNG except where necessary to differentiate between PNG and PNG(N.E.). The following sets out the agreement reached on March 15, 2006 among the parties that participated in the negotiated settlement process.

For reference purposes herein, the original 2006 revenue requirements application dated November 30, 2005 will be referred to as the "Original Application". The February 17, 2006 update to the Original Application will be referred to as the "Feb. 17'06 Update" and the March 9, 2006 update to the Feb. 17'06 Update will be referred to as the "Mar. 9'06 Update".

1. Company Use Gas Forecast and Estimated Annual Cost

The average actual annual plant fuel and lineheater use over the 2003 to 2005 period was 60,515 GJ. The parties agree to use the 60,515 GJ figure with an unaccounted for gas provision equal to zero subject to the implementation of a deferral account, for 2006 only, to record the extent to which actual unaccounted for gas volumes vary from zero. The resulting figures are as follows:

• PNG share of plant fuel and lineheaters –	12,194 GJ or 1.82 % of deliveries
• CNRL share of plant fuel –	48,321 GJ or 7.21 % of deliveries
• Unaccounted for gas -	0 GJ or 0% of deliveries
Totals	60,515 GJ or 9.03 % of deliveries

The projected 2006 Company use gas cost for rate making purposes will be based on actual prices applicable over the January to March 2006 period and the March 15, 2006 forward gas prices for the April to December 2006 period. This reduces the interim Company use gas rate of $1.403/GJ to a permanent rate of $0.635/GJ, effective January 1, 2006.

2. Operating and Maintenance Expenses

The 2006 budgeted operating and maintenance expenses, as set out in the regulatory schedules attached hereto, are accepted by the parties. The attached reflects the impact of PNG agreeing to reduce its 2006 forecast bad debt expense from $5,000 in the Original Application to $2,000 under this settlement agreement.

3. Administrative and General Expenses

The 2006 budgeted administrative and general expenses, as set out in the regulatory schedules attached hereto, are accepted by the parties. The attached includes the impact of PNG agreeing to remove employee bonuses from pensionable earnings in 2006 for the purpose of calculating pension benefits costs. This was agreed to in recognition of the Commission's direction to Terasen Gas to do so in an earlier proceeding. PNG's agreement to voluntarily comply with this direction is being made without prejudice to its right to make submissions to the Commission in future revenue requirements applications to allow PNG to include bonuses in pensionable earnings.

4. Benefits Surcharge under Shared Services from PNG to PNG(N.E.)

The benefits surcharge has decreased from 36.3 percent to 35.1 percent as a result of the parent company reducing its pension costs.

5. Account 721 Shared Services from PNG to PNG(N.E.)

Pension benefits costs are reduced due to the parent company reducing its pension costs.

6. Account 728 Shared Services from PNG to PNG(N.E.)

If PNG(N.E.) was a reporting issuer a conservative estimate of its Account 728 costs is $180,000 for fiscal and corporate expenses and $200,000 for directors fees and expenses. Hence, the parties agree that a total charge of only $87,000 (i.e. $84,000 for the FSJ/DC division and $3,000 for the Tumbler Ridge division) from PNG to PNG(N.E.) for Account 728 services is reasonable and is accepted by the parties. For greater clarity, these costs are not incremental to the provision of $7,000 under Account 728 for fiscal and corporate expense at Tab 1, Tumbler Ridge, page 5 of the Original Application because the $7,000 figure is only for the Tumbler Ridge division share of B.C. Utilities Commission administrative costs and a small provision for donations to the Tumbler Ridge service area. The schedule at Tab 1, Tumbler Ridge, page 5 will be modified to more clearly identify the breakdown of the total Account 728 costs of $10,000 for the Tumbler Ridge division.

7. Account 685 Shared Services Charges from PNG to PNG(N.E.)

Account 685 captures a wide range of activities including payroll, accounts payable, warehousing and technical services provided in Terrace. Fixed plant accounting is not a major component of Account 685. As a result, the level of costs in Account 685 reflects levels of activity not levels of assets. Key drivers of Account 685 costs are operating costs and capital expenditures, which are largely determinative of payroll, accounts payable activity, warehousing and technical services. The parties agree that employee count is a reasonable proxy for these drivers.

8. Amortization Expense

The 2005 plant upset deferral account is accepted as applied for by PNG.

9. Capital Additions

The 2006 capital additions forecast contained in the Feb. 17'06 Update is accepted by the parties including the provision for the above ground double walled waste water containment vessel at the Tumbler Ridge processing plant.

10. Gas Deliveries Forecast

The 2006 gas deliveries forecast for all customer classes as set out in the Feb. 17'06 Update is accepted by the parties with the exception of CNRL where the 2006 forecast will be increased from 500,000 GJ to 533,700 GJ.

11. RSAM-Revenue Stabilization Adjustment Mechanism Rate Rider for 2006

The RSAM rider applicable to residential and small commercial customers in 2006 is accepted at $0.531/GJ. A Table is attached showing the calculation of the 2006 RSAM rate rider, effective January 1, 2006.

12. Return on Equity and Capital Structure

The adjustments to the return on equity component of the cost of service set forth in the Mar. 9'06 Update are accepted by the parties. This is based on increasing the allowed return on equity from 8.94 percent in the Original Application to 9.45 percent in the Mar. 9'06 Update to reflect the impact of the Commission's 51 basis points increase to the return on equity for a benchmark low-risk utility. The 36 percent deemed common equity in the capital structure is accepted by the parties for rate making purposes in 2006.

13. <u>Lump Sum Settlement Allowance</u>

With a view to settling the 2006 revenue requirements application and thereby avoiding the cost of a public hearing, a 2006 settlement allowance reduction of $2,000 is accepted by the parties.

14. <u>Commission Staff Issues List</u>

The Commission Staff prepared an issues list to facilitate the negotiated settlement process. Attached for reference is a copy of the Commission Staff issues list.

15. <u>Regulatory Financial Schedules</u>

Attached are the following regulatory financial schedules to document the NSP 2006 settlement of the 2006 PNG(N.E.) Tumbler Ridge division revenue requirements application.

- NSP 2006 to Mar. 9'06 Update Cost of Service Comparison Table to show the changes made to the Mar. 9'06 Update to achieve the 2006 negotiated settlement.
- NSP 2006 vs. NSP 2005 Cost of Service Comparison Table
- Bill Comparison Table comparing residential and small commercial customer rates effective December 31, 2005 to NSP 2006 rates effective January 1, 2006.
- Bill Comparison Table comparing NSP 2006 residential and small commercial customer rates effective January 1, 2006 to proposed rates effective April 1, 2006 that reflect the NSP delivery charge rates in conjunction with proposed gas supply commodity changes effective April 1, 2006.
- Regulatory Schedules 1 to 5 showing the NSP 2006 and Mar. 9'06 Update figures in conjunction with the corresponding Actual 2005 figures.

It is noted that the cost of sales figure for NSP 2006 at Tab 1, Utility Income & Return, Schedule 1, line 16 is based on the November 28, 2005 forward gas price strip. The Company use gas cost forecast for NSP 2006 is based on the March 15, 2006 forward gas price strip. These items are also reflected in the Bill Comparison Table December 2005 to January 2006.

The parties noted that the Bill Comparison Table for the NSP January 1, 2006 to proposed April 1, 2006 rates comparison showed a significant impact from the proposed gas supply cost reduction effective April 1, 2006. The observation was made that the proposed rates effective April 1, 2006 were less than the rates that prevailed at the end of 2005.

Upon Commission approval of this settlement agreement PNG agrees to file, as an exhibit to these proceedings, a complete set of regulatory schedules in the form of the Feb 17'06 Update to document the negotiated settlement to the same level of detail as set forth in the Original Application.

PACIFIC NORTHERN GAS (N.E.) LTD

(Tumbler Ridge Division)

2006 Revenue Requirements Application

B.C. Utilities Commission Staff Prepared Issues List

Issues	References
Operating Costs	B-1, Tab Application TR, p. 5 B-8, Tab Application TR (Rev.), p. 3
1. Operating Costs Excluding Company Use Gas increased by $15,000	B-8, Tab Application TR (Rev.), p. 3
Processing Plant – Account 621 increased by $35,000 - Increase in contractor charges $10,000 - Standby charges of $18,000 transferred from account 685 - Telecommunications and license expense increase of $5,000	B-1, Tab Application TR, p. 6
2. Company Use Gas increased by $94,245 $28,867 of increase - 37% increase in commodity cost $65,378 of increase - 61% increase in volumes	B-1, Tab Application TR, p. 16 B-8, Tab 1 TR (Rev.), p. 3
3. Cost transfers From Account 677 to Account 667, total cost increase of $2,000 From Account 685 to Account 670, total cost decrease of $21,000	B-1, Tab Application TR, pp. 6-7 B-8, Tab 1 TR (Rev.), p. 3
4. Other General Operation- Account 688, decreased by $11,000	B-1, Tab Application TR, p. 7 B-8, Tab 1 TR (Rev.), p. 3
5. Uncollectible Accounts – Account 718, increased by $1,000, an 25% increase	B-8, Tab 1 TR (Rev.), p. 3

Issues	References
Maintenance Costs	
6. Maintenance Costs increased by $2,000 An increase of less than 5%	B-1, Tab Application TR, p. 6 B-8, Tab 1 TR (Rev.), p. 4
Administrative and General Costs	B-1, Tab Application TR, p. 8
7. Insurance – Account 723, decreased by $3,000 Change in insurance coverage GCVA to cover interruption losses	B-1, Tab Application TR, p. 8 B-8, Tab 1 TR (Rev.), p. 5
8. Employee benefits - Account 725, increased by $3,000	B-1, Tab Application TR, p. 7
Shared Service Charges by PNG to PNG(N.E.) TR	
9. Benefits surcharge appears to increase from 32.3% to 36.2% - Additional increase noted, but the percentage increase was not provided	B-1, Tab Application TR, p. 9 B-8, Tab 1 TR (Rev.), p. 5
10. Total shared service costs have increased by $16,000 This represents a 16.7% cost increase	B-1, Tab Application TR, pp. 10-11 B-8, Tab 1 TR (Rev.), p. 5
11. Shared service allocation factors Account 685 - Accounts payables processing, plant accounting and warehouse technical services allocated on employee count	B-1, Tab Application TR, p. 11 B-10, Response to BCUC IR FSJ/DC, Questions 42.1 – 42.4, pp. 8-10
12. System Operations Shared Service from Parent – Account 685 increased by $2,000	B-8, Tab 1 TR (Rev.), p. 3
13. Customer Care costs increased by $3,000 Customer billing- Account 713 increased by $3,000	B-8, Tab 1 TR (Rev.), p. 3
14. Administration Shared Service from Parent - Account 721, increased by $8,000	B-1, Tab Application TR, p. 9 B-8, Tab 1 TR (Rev.), p. 5
15. New allocated costs of $3,000 for Fiscal and corporate expense Shared Service from Parent – Account 728	B-1, Tab Application TR, p. 9 B-8, Tab 1 TR (Rev.), p. 5

Issues	References
16. Transfers to Capital - $9,000 Increase in capitalization rate to 3.5%	B-1, Tab Application TR, p. 11 B-8, Tab 1 TR (Rev.), p. 2
17. Property Taxes - $38,000 Same as Decision 2005	B-1, Tab Application TR, p. 11 B-8, Tab 1 TR (Rev.), p. 6
18. Depreciation – $163,000 Increased by $18,000	B-1, Tab Application TR, p. 12 B-8, Tab 2 TR (Rev.), p. 4
19. Amortization Tumbler Ridge Plant Upset Deferral$172,385 20. Other Income - $8,000 $5,000 decrease - Sale of rental house	B-1, Tab Application TR, p. 12 B-8, Tab 2 TR (Rev.), p. 7 B-3, Response to BCUC IR 34.1 Commission Order G-122-05 B-1, Tab Application TR, p. 12 B-8, Tab 1 TR (Rev.), p. 7
21. Income Taxes - $67,000	B-13, Application (Rev.), p. 3
22. Return on Common Equity ROE of 9.45% reflects Commission Order G-14-06	B-1, Tab Application TR, p. 13 B-13, Application (Rev.), p. 1
23. Capital Structure – 36% Equity Same as Decision 2005	B-1, Tab Application TR, p. 13
24. Long term loan of $0.15 million from PNG	B-1, Tab Application TR, pp. 13-14
25. Interest Expense - $63,000	B-8, Tab 3 TR (Rev.), p. 1 B-1, Tab Application TR, p. 15
26. Capital Additions increased by $31,000 Waste water containment vessel	B-1, Tab Application TR, p. 16 B-8, Tab 2 TR (Rev.), p. 1
27. Load Forecast TR Residential – 79,245 GJ Small Commercial – 30,004 GJ Large Commercial – 21,000 GJ Industrial Transportation –500,000 GJ	 B-1, Tab Application TR, p. 17
28. RSAM Rate Riders	B-1, Tab Application TR, p. 21
29. Gas Supply Cost Charge Changes/GCVA Riders 2005 Fourth Quarter Gas Supply Cost Report	B-1, Tab Application TR, pp. 21-22
30. Emergency response time 3 calls with response times > 40 min.	B-3, Response to BCUC IR TR, Question 38.2, p. 60

Pacific Northern Gas (N.E.) Ltd.

(Fort St. John/Dawson Creek Division)

2006 Revenue Requirements Application

NEGOTIATED SETTLEMENT AGREEMENT

March 15, 2006

Introduction

PNG(N.E.) representatives, Commission Staff and registered intervenors met on March 13, 14 and 15, 2006 for the purpose of negotiating a settlement of PNG(N.E.)'s Fort St. John/Dawson Creek (FSJ/DC) division 2006 revenue requirements application. For ease of reference PNG(N.E.) will be referred to in this settlement agreement as PNG except where necessary to differentiate between PNG and PNG(N.E.). The following sets out the agreement reached on March 15, 2006 among the parties that participated in the negotiated settlement process.

For reference purposes herein, the original 2006 revenue requirements application dated November 30, 2005 will be referred to as the "Original Application". The February 17, 2006 update to the Original Application will be referred to as the "Feb. 17'06 Update" and the March 9, 2006 update to the Feb. 17'06 Update will be referred to as the "Mar. 9'06 Update".

1. Operating and Maintenance Expenses

The 2006 budgeted operating and maintenance expenses, as set out in the regulatory schedules attached hereto, are accepted by the parties. The attached reflects the impact of PNG agreeing to assume a bad debt expense factor of 0.5 percent to calculate the 2006 budgeted allowance for bad debt. PNG will review its collection policies and submit a report to the Commission on initiatives to be taken by PNG to reduce bad debt over time. The report will be filed on or before July 1, 2006.

2. <u>Company Use Gas Forecast and Estimated Annual Cost</u>

PNG agrees to set its 2006 provision Company use gas requirements at 1.11 percent of forecast gas deliveries subject to the implementation of a deferral account, for 2006 only, to record the extent to which actual unaccounted for gas volumes vary from the forecast. The unaccounted for gas volume is equal to the difference between 1.11 percent of forecast volumes and the provision for lineheaters, office, blowdowns and losses based on the average of actual figures for the 2001 to 2005 five year period. The resulting figures are as follows:

•	Lineheaters and office –	15,133 GJ or 0.32 % of deliveries
•	Blowdowns and losses –	4,819 GJ or 0.10 % of deliveries
•	Unaccounted for gas –	33,272 GJ or 0.69 % of deliveries
	Totals	53,224 GJ or 1.11 % of deliveries

The projected 2006 Company use gas cost for rate making purposes will be based on actual prices applicable over the January to March 2006 period and the March 15, 2006 forward gas prices for the April to December 2006 period. This reduces the interim Company use gas rate of $0.15/GJ to a permanent rate of $0.087/GJ, effective January 1, 2006.

3. <u>Administrative and General Expenses</u>

The 2006 budgeted administrative and general expenses, as set out in the regulatory schedules attached hereto, are accepted by the parties. The attached includes the impact of PNG agreeing to remove employee bonuses from pensionable earnings in 2006 for the purpose of calculating pension benefits costs. This was agreed to in recognition of the Commission's direction to Terasen Gas to do so in an earlier proceeding. PNG's agreement to voluntarily comply with this direction is being made without prejudice to its right to make submissions to the Commission in future revenue requirements applications to allow PNG to include bonuses in pensionable earnings.

4. <u>Benefits Surcharge under Shared Services from PNG to PNG(N.E.)</u>

The benefits surcharge has decreased from 36.3 percent to 35.1 percent as a result of the parent company reducing its pension costs.

5. <u>Account 721 Shared Services from PNG to PNG(N.E.)</u>

Pension benefits costs are reduced due to the parent company reducing its pension costs.

6. Account 728 Shared Services from PNG to PNG(N.E.)

If PNG(N.E.) was a reporting issuer a conservative estimate of its Account 728 costs is $180,000 for fiscal and corporate expenses and $200,000 for directors fees and expenses. Hence, the parties agree that a total charge of only $87,000 (i.e. $84,000 for the FSJ/DC division and $3,000 for the Tumbler Ridge division) from PNG to PNG(N.E.) for Account 728 services is reasonable and is accepted by the parties. For greater clarity, these costs are not incremental to the provision of $49,000 under Account 728 for fiscal and corporate expense at Tab 1, FSJ/DC, page 5 of the Original Application because the $49,000 figure is only for the FSJ/DC division share of B.C. Utilities Commission administrative costs and a small provision for donations to the FSJ/DC service area. The schedule at Tab 1, FSJ/DC, page 5 will be modified to show the breakdown of the total Account 728 costs of $133,000 for the FSJ/DC division into the fiscal and corporate costs from PNG, the Commission costs and donations segments.

7. Account 685 Shared Services Charges from PNG to PNG(N.E.)

Account 685 captures a wide range of activities including payroll, accounts payable, warehousing and technical services provided in Terrace. Fixed plant accounting is not a major component of Account 685. As a result, the level of costs in Account 685 reflects levels of activity not levels of assets. Key drivers of Account 685 costs are operating costs and capital expenditures, which are largely determinative of payroll, accounts payable activity, warehousing and technical services. The parties agree that employee count is a reasonable proxy for these drivers.

8. Gas Deliveries Forecast

The 2006 gas deliveries forecast for all customer classes as set out in the Feb. 17’06 Update is accepted by the parties.

9. RSAM-Revenue Stabilization Adjustment Mechanism Rate Rider for 2006

The RSAM rider applicable to residential and small commercial customers in 2006 is accepted at $0.114/GJ. A Table is attached showing the calculation of the 2006 RSAM rate rider, effective January 1, 2006.

10. Return on Equity and Capital Structure

The adjustments to the return on equity component of the cost of service set forth in the Mar. 9'06 Update are accepted by the parties. This is based on increasing the allowed return on equity from 8.69 percent in the Original Application to 9.20 percent in the Mar. 9'06 Update to reflect the impact of the Commission's 51 basis points increase to the return on equity for a benchmark low-risk utility. The 36 percent deemed common equity in the capital structure is accepted by the parties for rate making purposes in 2006.

11. Tracking of Customer Complaints

PNG will attempt to keep a record of customer complaints received from the FSJ/DC division customers in 2006 and prepare a report to the Commission summarizing the results. The report will contain a discussion of whether it would be useful for PNG to continue tracking complaints in 2007 and beyond.

12. Lump Sum Settlement Allowance

With a view to settling the 2006 revenue requirements application and thereby avoiding the cost of a public hearing, a 2006 settlement allowance reduction of $50,000 is accepted by the parties.

13. Commission Staff Issues List

The Commission Staff prepared an issues list to facilitate the negotiated settlement process. Attached for reference purposes is a copy of the Commission Staff issues list.

14. Regulatory Financial Schedules

Attached are the following regulatory financial schedules to document the NSP 2006 settlement of the 2006 PNG(N.E.) FSJ/DC division revenue requirements application.

- NSP 2006 to Mar. 9’06 Update Cost of Service Comparison Table to show the changes made to the Mar. 9’06 Update to achieve the 2006 negotiated settlement.
- NSP 2006 vs. NSP 2005 Cost of Service Comparison Table
- Bill Comparison Table comparing residential and small commercial customer rates effective December 31, 2005 to NSP 2006 rates effective January 1, 2006.
- Bill Comparison Table comparing NSP 2006 residential and small commercial customer rates effective January 1, 2006 to proposed rates effective April 1, 2006 that reflect the NSP 2006 delivery charge rates in conjunction with PNG’s proposed gas supply commodity rate changes effective April 1, 2006.
- Regulatory Schedules 1 to 5 showing the NSP 2006 and Mar. 9’06 Update figures in conjunction with the corresponding Actual 2005 figures.

It is noted that the cost of sales figure for NSP 2006 at Tab 1, Utility Income & Return, Schedule 1, line 16 is based on the November 28, 2005 forward gas price strip. The change in the cost of sales from the March 9’06 Update to the NSP 2006 figure reflects a correction to PNG’s gas cost flow through model and does not affect the Commission approved permanent gas supply commodity rates effective January 1, 2006. The Company use gas cost forecast for NSP 2006 is based on the March 15, 2006 forward gas price strip. These items are also reflected in the Bill Comparison Table December 2005 to January 2006.

The parties noted that the Bill Comparison Table for the NSP January 1, 2006 to proposed April 1, 2006 rates comparison showed a significant impact from the proposed gas supply cost reduction effective April 1, 2006. The observation was made that the proposed rates effective April 1, 2006 were less than the rates that prevailed at the end of 2005.

Upon Commission approval of this settlement agreement PNG agrees to file, as an exhibit to these proceedings, a complete set of regulatory schedules in the form of the Feb 17’06 Update to document the negotiated settlement to the same level of detail as set forth in the Original Application.

PACIFIC NORTHERN GAS (N.E.) LTD.

(Fort St. John/Dawson Creek Division)

2006 Revenue Requirements Application

B.C. Utilities Commission Staff Prepared Issues List

Issues	References
Operating Costs 1. Labour cost increase of $94,000 IBEW contract increases - $55,000 Higher standby charges - $5,000 Other Increases - $34,000	B-1, Tab Application FSJ/DC, p. 5 B-1, Tab Application FSJ/DC, p. 6
2. Company Use Gas increased by $474,000 $397,943 of increase - higher volumes of 43,025 GJ $89,618 of increase - 40% increase in commodity cost	B-1, Tab Application FSJ/DC, p. 16 B-9, Tab 1 FSJ/DC (Rev.), p. 3
3. Cost transfers From Account 677 to Account 667, total cost increase of $6,000 From Account 685 to Account 670, total cost increase of $30,000	B-1, Tab Application FSJ/DC, pp. 6-7
4. Other General Operation- Account 688, increased by $59,000 Reallocation of vehicle costs $30,000 Overtime vacation pay $7,000 Labour cost increase $17,000	B-1, Tab Application FSJ/DC, p. 7 B-9, Tab 1 FSJ/DC (Rev.), p. 3
5. Uncollectible Accounts – Account 718, increased by $104,000 Actual 2005 Bad Debt Factor of 0.63% used to forecast 2006 5-year average actual Bad Debt Factor of 0.46%	B-1, Tab Application FSJ/DC, p. 7 B-3, , Response to BCUC IR FSJ/DC, Questions 5.1 – 5.3, pp. 4 - 5

Issues	References
Maintenance Costs	
6. Maintenance Costs decreased by $25,000	B-1, Tab Application FSJ/DC, p. 7
Administrative and General Costs	B-1, Tab Application FSJ/DC, p. 8
7. Insurance – Account 723, decreased by $19,000 Change in insurance coverage GCVA to cover interruption losses	B-1, Tab Application FSJ/DC, p. 8 B-9, Tab 1 FSJ/DC (Rev.), p. 5
8. Employee benefits - Account 725, increased by $50,000	B-1, Tab Application FSJ/DC, p. 8 B-9, Tab 1 FSJ/DC (Rev.), p. 5
Shared Service Charges by PNG to PNG(N.E.)	
9. Benefits surcharge appear to be increased from 32.3% to 36.3% Additional increase noted, but the percentage increase was not provided	B-1, Tab Application FSJ/DC, p. 10 B-9, Application 1 FSJ/DC (Rev.), p. 2
10. Total shared service costs have increased by $299,000 This represents a 24.6% cost increase	B-1, Tab Application FSJ/DC, pp. 10-11 B-9, Tab 1 FSJ/DC (Rev.), p. 5
11. System Operations Shared Service from Parent – Account 685 increased by $52,000	B-9, Tab 1 FSJ/DC (Rev.), p. 3
12. Customer Care costs increased by $53,000 Customer contracts - Account 711 decreased by $1,000 Customer billing- Account 713 increased by $54,000 Credit and collections - Account 714 decreased by $5,000 Meter reading - Account 712 increased by $1,000	B-9, Tab 1 FSJ/DC (Rev.), p. 3 B-6, p Response to PRRD IR FSJ/DC, Questions 9.1 and 9.2, p. 6

Issues	References
13. Administration Shared Service from Parent - Account 721, increased by $115,000	B-1, Tab Application FSJ/DC, p. 10 B-9, Tab 1 FSJ/DC (Rev.), p. 5
14. New allocated costs of $84,000 for Fiscal and corporate expense Shared Service from Parent – Account 728	B-1, Tab Application FSJ/DC, p. 10 B-9, Tab 1 FSJ/DC (Rev.), p. 5
15. Shared service allocation factors Account 685 - Accounts payable processing, plant accounting and warehouse technical services allocated on employee count	B-1, Tab Application FSJ/DC, p. 11 B-10, Response to BCUC IR FSJ/DC, Questions 42.1 – 42.4, p. 59
16. Transfers to Capital	B-9, Tab 1 FSJ/DC (Rev.), p. 2
17. Property Taxes	B-9, Tab 1 FSJ/DC (Rev.), p. 1
18. Depreciation	B-9, Tab 1 FSJ/DC (Rev.), p. 1
19. Amortization	B-9, Tab 1 FSJ/DC (Rev.), p. 1
20. Other Income	B-9, Tab 1 FSJ/DC (Rev.), p. 1
21. Income Taxes	B-9, Tab 3 FSJ/DC (Rev.), p. 1
22. Return on Common Equity	B-9, Tab 5 FSJ/DC (Rev.), p. 1
23. Capital Structure	B-9, Tab 5 FSJ/DC (Rev.), p. 1
24. Long term loan of $7.85 million from PNG	B-1, Tab Application FSJ/DC, pp. 14-16
25. Interest Expense	B-9, Tab 5 FSJ/DC (Rev.), p. 1
26. Capital Additions	B-9, Tab 2 FSJ/DC (Rev.), p. 1
27. Load Forecast FSJ Residential – 1,103,434 GJ Small Commercial – 811,065 GJ Large Commercial – 165,102 GJ Small Industrial Sales – 308,439 GJ Small Industrial T-Service – 1,072, 559	B-9, Tab Rates FSJ/DC, p.10

Issues	References
28. Load Forecast DC Residential – 620,742 GJ Small Commercial – 485,979 GJ Large Commercial – 151,998 GJ Small Industrial Sales- 75,660 GJ	B-9, Tab Rates FSJ/DC, p.10
29. RSAM Rate Riders	B-1, Tab Application FSJ/DC, p. 23
30. Gas Supply Cost Charge Changes/GCVA Riders - 2005 Fourth Quarter Gas Supply Cost Report - Legal fees associated with Samson Supreme Court action treated as a GCVA cost	B-3, Response to BCUC IR FSJ/DC, Question 39.6, p. 69
31. Emergency response time - 37 calls with response times > 40 min	B-3, Response to BCUC IR FSJ/DC, Question 37.1, p. 59
32. Declining Customer Service	B-6, Response to PRRD IR FSJ/DC, Question 9.1, p.6

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Articled Student

March 29, 2006

VIA E-MAIL AND MAIL

William J. Grant
Transition Advisor
Regulatory Affairs & Planning
BC Utilities Commission
Sixth Floor - 900 Howe Street
Vancouver, BC V6Z 2N3

Re: PNG (N.E.) Ltd. Ft St. John/Dawson Creek and Tumbler Ridge Divisions Negotiated Settlement 2006 Revenue Requirements Application

I act for BC Old Age Pensioners' Organization, Active Support Against Poverty, Council of Senior Citizens' Organizations, federated anti-poverty groups of BC, End Legislated Poverty, and BC Coalition of People with Disabilities (collectively known as BCOAPO).

BCOAPO confirms its acceptance of these settlements.

BCOAPO is aware, given the relationship between PNG-West and PNG (N.E.), that the latter's revenue requirement may be impacted by the resolution of the issue raised by BCOAPO with respect to the PNG-West proposed Negotiated Settlement.

Yours sincerely,

BC PUBLIC INTEREST ADVOCACY CENTRE

Richard J. Gathercole
Executive Director

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c: Craig Donohue

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March 28, 2006

VIA EMAIL

B.C. Utilities Commission
Box 250, 900 Howe Street
Sixth Floor
Vancouver, BC V6Z 2N3

Attention: William J. Grant, Transition Advisor

Dear Mr. Grant:

Re: Pacific Northern Gas Ltd. (N.E.) ("PNG-NE")
Negotiated Settlement Agreement
2006 Revenue Requirements Application

We have reviewed the final Negotiated Settlement Agreement for PNG-NE's 2006 Revenue Requirements Application. The Haisla Nation takes no position on the Agreement.

Yours truly,

DONOVAN & COMPANY

Jennifer M. Griffith

Jennifer Griffith
JG/MS

cc: Chief Steve Wilson and Council, Haisla Nation

cc: Mr. Craig Donohue
Director, Regulatory Affairs and Gas Supply, Pacific Northern Gas Ltd.

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REPLY TO: VANCOUVER OFFICE

VIA E-MAIL

March 31, 2006

Mr. William Grant
BC Utilities Commission
Sixth Flr., 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Dear Mr. Grant:

Re: **Pacific Northern Gas (N.E.) Ltd. Applications - 2006 Revenue Requirements**
Our File No. 33-370

We are writing further to your letter of March 28, 2006. We wish to advise that the Peace River Regional District accepts the negotiated settlement agreements for PNG (N.E.)'s 2006 Revenue Requirements applications for the Fort St. John/Dawson Creek and Tumbler Ridge division.

Please contact the writer at your earliest convenience if you wish to discuss this matter further.

Yours very truly,

LIDSTONE, YOUNG, ANDERSON

C. MacEachern

Carolyn M. MacEachern
maceachern@lya.bc.ca

CMM/tr

cc: Wayne Hiebert (via facsimile)

Pacific Northern Gas Ltd.
Suite 950
1185 West Georgia Street
Vancouver, BC V6E 4E6
Tel: (604) 691-5673
Tel: (604) 697-6210
Email: cdonohue@png.ca

Craig P. Donohue
Director, Regulatory Affairs & Gas Supply

Via E-Mail and Courier

March 30, 2006

B.C. Utilities Commission
6th Floor - 900 Howe Street
Vancouver, B.C.
V6Z 2N3

File No.: 4.2.7 (2006)

Attention: William J. Grant
Transition Advisor
Regulatory Affairs & Planning

Dear Sir:

Re: PNG(N.E.) Negotiated Settlements for the Fort St. John/Dawson Creek and Tumbler Ridge Divisions' 2006 Revenue Requirements Applications

Further to your letter dated March 28, 2006 enclosing the Negotiated Settlement Agreements for the PNG(N.E.) Fort. St. John/Dawson Creek and Tumbler Ridge Divisions' 2006 Revenue Requirements Application, along with supporting documents, PNG hereby confirms its acceptance of the settlements subject to the remarks below concerning the regulatory schedules attached to the settlement agreements.

Fort St. John/Dawson Creek Division

The regulatory schedules attached to the settlement agreement distributed under cover of your letter dated March 28, 2006 showed a projected NSP 2006 revenue sufficiency of $52,000. Attached to this letter is a revised set of NSP 2006 regulatory schedules for the FSJ/DC division showing a slightly lower revenue sufficiency of $44,000. The reduction results from adjustments to the amortization expense calculation for 2006. In PNG's response 41.0 to BCUC IR No. 2 for the FSJ/DC division, PNG advised that all of BCOAPO's 2005 hearing costs award had been included in the PNG-West division when about 50 percent should have been allocated to PNG(N.E.). In the response PNG advised this adjustment would be made in the final 2006 schedules. Unfortunately, this adjustment was not made before the settlement schedules were prepared. The result of allocating a portion of the BCOAPO 2005 hearing costs to FSJ/DC is in an overall increase of $8,000 in the 2006 cost of service compared to the original NSP settlement schedules.

PNG understands that the Negotiated Settlement Agreement, the regulatory schedules attached thereto and letters of comment by the participants in the NSP 2006 meetings will be made public and forwarded to the Commission for its review on Friday, March 31, 2006. PNG requests that the enclosed settlement regulatory schedules be attached to the Negotiated Settlement Agreement that is made public and forwarded to the Commission in place of the schedules that were distributed with the draft settlement agreement. This will avoid confusion that may arise if the draft settlement regulatory schedules are distributed together with this letter of comment and the enclosed revised NSP 2006 settlement regulatory schedules. In addition, it is recommended that when this letter of comment is attached to the documents that are made public, that the attachment not be included assuming the attachment is made part of the Negotiated Settlement Agreement. When the Commission, non NSP participants and others read this letter of comment, they will have been properly advised of this slight change to the NSP 2006 settlement regulatory schedules accordingly.

Tumbler Ridge Division

The revenue deficiency of $83,000 set forth in the Tumbler Ridge division settlement regulatory schedules distributed with the draft NSP 2006 settlement agreement has not changed as a result of PNG's final review. PNG considered the hearing costs budget for 2006 in the Tumbler Ridge division was sufficient to cover the NSP 2006 settlement meetings and their share of the BCOAPO 2005 hearing costs. Hence, a change to the hearing costs amortization expense similar to that in the FSJ/DC division was not required in the Tumbler Ridge division. However, for completeness, enclosed is a set of the NSP 2006 settlement regulatory schedules that were printed at the same time as the FSJ/DC division revised schedules. PNG requests that the attached be used in the settlement agreement that is forwarded to the Commission, non NSP participants and others on Friday, March 31, 2006.

Please direct any questions regarding this letter to my attention.

Yours truly,

C.P. Donohue

cc. P. Nakoneshny

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

NSP 2006 to Revised Mar. 9 '06
COST OF SERVICE COMPARISON
($000)

EXPENSES	NSP 2006	Revised 2006 App. Mar. 9 '06	Difference
Operating			
Labour	209	209	0
Other	279	282	(4)
Sub-total	487	491	(4)
Maintenance			
Labour	22	22	0
Other	39	39	0
Sub-total	62	62	0
Administrative and General			
Labour	0	0	0
Total Company Benefits	68	69	(1)
Other	71	71	(0)
Sub-total	139	140	(1)
Total (O, M, A & G) Excluding Co. Use	**688**	**693**	**(5)**
Transfers to Capital Operating	(4)	(4)	0
Transfers to Capital Admin. & Gen.	(5)	(5)	0
Property Taxes	38	38	0
Depreciation	163	163	0
Amortization	17	20	(4)
Other Income	(8)	(8)	0
2006 Settlement Allowance	(2)	0	(2)
Total Expenses Excluding Co, Use	**886**	**896**	**(11)**
Income Taxes	68	68	(0)
Return on Common Equity	39	39	0
Short Term Debt	2	2	0
Long Term Debt	61	61	0
Preferred Shares	0	0	0
Total Cost of Service Excluding Co. Use	**1056**	**1067**	**(11)**
Company Use Gas	87	185	
Total Cost of Service Including Co. Use	**1143**	**1252**	
2005 to 2006 Cost of Service Increase	**55**	**66**	**(11)**
2005 to 2006 Margin Decrease	**28**	**45**	**(17)**
2006 Revenue Deficiency	**83**	**111**	**(28)**

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

NSP 2006 vs. Decision 2005
COST OF SERVICE COMPARISON
($000)

EXPENSES	NSP 2006	Decision 2005	Difference Total	Difference Subtotal
Operating				
Labour	209	227	(18)	
Other	279	250	29	
Sub-total	487	476	11	
Maintenance				
Labour	22	21	1	
Other	39	39	1	
Sub-total	62	60	2	
Administrative and General				
Labour	0	0	0	
Total Company Benefits	68	66	2	
Other	71	64	7	
Sub-total	139	130	10	
Total (O, M, A & G) Excluding Co. Use	**688**	**666**	**22**	**22**
Transfers to Capital Operating	(4)	(5)	1	
Transfers to Capital Admin. & Gen.	(5)	(3)	(2)	
Property Taxes	38	38	(1)	
Depreciation	163	145	17	
Amortization	17	14	3	
Other Income	(8)	(13)	5	
2006 Settlement Alowance	(2)	0	(2)	22
Total Expenses Excluding Co, Use	**886**	**841**	**44**	**44**
Income Taxes	68	62	6	
Return on Common Equity	39	37	2	
Short Term Debt	2	2	0	
Long Term Debt	61	58	3	
Preferred Shares	0	0	0	11
Total Cost of Service Excluding Co. Use	**1056**	**1001**	**55**	**55**
Company Use Gas	87	86		
Total Cost of Service Including Co. Use	**1143**	**1087**		

2005 to 2006 Cost of Service Increase	**55**
2005 to 2006 Margin Decrease	**28**
2006 Revenue Deficiency	**83**

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

Bill Comparison
December 2005 to January 2006

Customer Classification	Annual Use	Permanent Rates Dec. 31, 2005 $ / GJ	Annual Bill Estimate $	NSP Rates Jan. 1, 2006 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	%
Residential:	74.6 GJ						
Monthly Fixed Charge @ 8.50 / mo.		1.367	102.00	1.367	102.00	0.00	
Delivery Charge		5.387	401.87	5.930	442.38	40.51	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.284	21.19	0.531	39.61	18.42	
Interim Rate Refund Rider		(0.135)	(10.07)	0.000	0.00	10.07	
			514.99		583.99	69.00	13.4%
Gas Supply Charge		8.753	652.97	8.822	658.12	5.15	
GCVA Rider		(0.350)	(26.11)	(0.350)	(26.11)	0.00	
			626.86		632.01	5.15	0.8%
		$15.306 /GJ	$1,141.85	$16.300 /GJ	$1,216.00	$74.15	6.5%
Small Commercial:	553.9 GJ						
Monthly Fixed Charge @ 8.50 / mo.		0.184	102.00	0.184	102.00	0.00	
Delivery Charge		4.719	2,613.85	5.116	2,833.75	219.90	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.284	157.31	0.531	294.12	136.81	
Interim Rate Refund Rider		(0.083)	(45.97)	0.000	0.00	45.97	
			2,827.19		3,229.87	402.69	14.2%
Gas Supply Charge		8.753	4,848.29	8.822	4,886.51	38.22	
GCVA Rider		(0.350)	(193.87)	(0.350)	(193.87)	0.00	
			4,654.42		4,692.64	38.22	0.8%
		$13.507 /GJ	$7,481.61	$14.303 /GJ	$7,922.51	$440.90	5.9%

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

Bill Comparison
January 2006 to April 2006

Customer Classification	Annual Use	NSP Rates Jan. 1, 2006 $ / GJ	Annual Bill Estimate $	Proposed Rates Apr. 1, 2006 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	%
Residential:	74.6 GJ						
Monthly Fixed Charge @ 8.50 / mo.		1.367	102.00	1.367	102.00	0.00	
Delivery Charge		5.930	442.38	5.930	442.38	0.00	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.531	39.61	0.531	39.61	(0.00)	
Interim Rate Refund Rider		0.000	0.00	0.000	0.00	0.00	
			583.99		583.99	(0.00)	0.0%
Gas Supply Charge		8.822	658.12	6.822	508.92	(149.20)	
GCVA Rider		(0.350)	(26.11)	(0.350)	(26.11)	0.00	
			632.01		482.81	(149.20)	-23.6%
		$16.300 /GJ	$1,216.00	$14.300 /GJ	$1,066.80	($149.20)	-12.3%
Small Commercial:	553.9 GJ						
Monthly Fixed Charge @ 8.50 / mo.		0.184	102.00	0.184	102.00	0.00	
Delivery Charge		5.116	2,833.75	5.116	2,833.75	0.00	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.531	294.12	0.531	294.12	0.00	
Interim Rate Refund Rider		0.000	0.00	0.000	0.00	0.00	
			3,229.87		3,229.87	0.00	0.0%
Gas Supply Charge		8.822	4,886.51	6.822	3,778.71	(1,107.80)	
GCVA Rider		(0.350)	(193.87)	(0.350)	(193.87)	0.00	
			4,692.64		3,584.84	(1,107.80)	-23.6%
		$14.303 /GJ	$7,922.51	$12.303 /GJ	$6,814.71	($1,107.80)	-14.0%

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

Determination of 2006 Revenue Stabilization Adjustment Mechanism (RSAM) Rider

	Residential	**Small Commercial**	**Total**
Actual RSAM Balance 12/31/04	$121,531	$26,593	$148,123
Recovery of RSAM in 2005 to 12/31/05	($20,308)	($7,271)	($27,580)
RSAM Deferral in 2005 to 12/31/05	$46,681	$16,269	$62,950
Actual RSAM Balance 12/31/05	**$147,904**	**$35,590**	**$183,494**
Years of Amortization	3	3	3
RSAM Balance divided by Years of Amortization equals 2006 Amortization	$49,301	$11,863	$61,165
Forecast 2006 Deliveries (GJ)	79,247	36,004	115,250
One Year of Amortization divided by 2006 Deliveries equals RSAM Rate Rider ($/GJ)	**0.622**	**0.330**	**0.531**

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

UTILITY INCOME & RETURN

SCHEDULE 1
(000's)

Line No.		NSP 2006	Mar. 9 06 Update	Actual 2005	Source
1	Energy sales (TJ)	136	136	126	Tab Rates, page 5
2	Average rate per GJ	$15.15	$16.04	$13.61	
3					
4	Transportation service (TJ)	534	500	563	Tab Rates, page 5
5	Average rate per GJ	$0.53	$0.54	$0.58	
6					
7	Total deliveries (TJ)	670	636	689	Tab Rates, page 5
8					
9	Utility revenue				
10	Energy sales	$2,002	$2,099	$1,719	
11	Interim rates - sales	63	87	-	Tab Rates, page 3
12	Transportation service	260	244	324	
13	Interim rates - transportation	21	24	1	Tab Rates, page 3
14					
15		2,346	2,454	2,044	
16	Cost of sales	1,203	1,202	920	Tab Rates, page 4
17					
18	Gross margin	1,142	1,251	1,124	
19					
20	Operating expenses	570	672	522	Tab 1, page 2, line 6
21	Maintenance expenses	62	62	40	Tab 1, page 2, line 10
22	Admin. & general expenses	134	135	118	Tab 1, page 2, line 16
23	Property taxes, BC capital tax	38	38	38	Tab 1, page 6, line 4
24	Depreciation	163	163	144	Tab 2, page 3, line 45
25	Amortization	17	20	13	Tab 2, page 4, line 14
26	Investment income, other revenue	(8)	(8)	(8)	Tab 1, page 7, line 7
27	2006 Settlement Allowance	(2)		0	
28		972	1,081	868	
29					
30	Earned return before income taxes	170	170	256	
31	Income taxes	68	68	92	Tab 3, page 1, line 14
32					
33	Earned return	$102	$102	$164	
34					
35	Utility rate base	$1,153	$1,151	$1,127	Tab 2, page 1, line 20
36					
37	Return on rate base	8.87%	8.87%	14.52%	Tab 5, page 1, line 23

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

UTILITY RATE BASE

SCHEDULE 2
(000's)

Line No.		NSP 2006	Mar. 9 06 Update	Actual 2005	Source
1	Plant in service beginning of year	$7,749	$7,749	$7,607	Tab 2, page 2, line 46
2	Additions	173	173	142	Tab 2, page 2, line 46
3	Disposals	-	-	-	Tab 2, page 2, line 46
4					
5	Plant in service end of year	7,921	7,921	7,749	
6	Accumulated depreciation	5,256	5,256	5,007	Tab 2, page 3, line 45
7					
8	Net plant in service end of year	2,665	2,665	2,742	
9					
10	Net plant beginning of year	2,742	2,742	2,853	Tab 2, pages 2 & 3, lines 46 & 39
11					
12	Net plant in service midyear	2,704	2,704	2,797	
13	Contributions for construction	(1,257)	(1,257)	(1,338)	Tab 2, page 12, line 13
14	Unamortized deferred charges	241	241	204	Tab 2, page 4, line 8
15	Deferred income taxes	(415)	(415)	(415)	
16	Reserve for damages	(155)	(155)	(155)	
17	Cash working capital	35	33	41	Tab 2, page 6, line 9
18	Other working capital	-	-	(7)	Tab 2, page 11, line 15
19					
20	Utility rate base, midyear	$1,153	$1,151	$1,127	

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

INCOME TAXES

SCHEDULE 3
(000's)

Line No.		NSP 2006	Mar. 9 06 Update	Actual 2005	Source
1	**Calculation of Taxable Income**				
2	Earned return before income taxes	$170	$170	$256	Tab 1, page 1, line 30
3	Interest	(63)	(63)	(62)	Tab 5, page 1, lines 4, 9 & 21
4	Permanent differences	-	-	0	
5	Timing differences	92	93	69	Tab 3, page 1, line 25
6					
7	Taxable income	$199	$200	$263	
8					
9	**Calculation of Income Tax Expense**				
10	Income taxes payable	$66	$66	$89	
11	Part I.3 tax	2	2	3	
12	Deferred income tax	-	-	-	
13					
14	Income tax expense	$68	$68	$92	
15					
16	**Particulars of Timing Differences**				
17	A. Tax Effects Subject To Flowthrough				
18	Depreciation	$163	$163	$144	Tab 1, page 1, line 24
19	Amortization	17	20	13	Tab 1, page 1, line 25
20	Capital cost allowance	(79)	(79)	(82)	
21	Deferred charges	-	-	-	
22	Overheads capitalized	(7)	(7)	(6)	
23	Other	(0)	(4)	(1)	
24					
25	Timing differences	$92	$93	$69	
26					
27	Tax rate	33.00%	33.00%	33.75%	
28	Surtax rate	1.12%	1.12%	1.12%	
29	Deferred tax rate	33.00%	33.00%	33.75%	

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

COMMON EQUITY

SCHEDULE 4
(000's)

Line No.		NSP 2006	Mar. 9 06 Update	Actual 2005	Source
1	Opening balance				
2	Share capital	$680	$680	$680	
3	Contributed surplus	-	-	-	
4	Retained earnings	(444)	(444)	(540)	
5					
6		236	236	140	
7					
8	Net income	$39	$39	$96	
9	Shares Issued	319	318	-	
10	Preferred dividends	-	-	-	
11	Common dividends	-	-	-	
12					
13	Closing balance	$594	$593	$236	
14					
15					
16	Midyear common equity	$415	$415	$188	
17	Investment in Non Utility	-	-	-	
18					
19		$415	$415	$188	
20					
21	Deemed utility common equity	$415	$415	$406	

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

RETURN ON CAPITAL

SCHEDULE 5
(000's)

Line No.		NSP 2006	Mar. 9 06 Update	Actual 2005	Source
1	Short term borrowings	$33	$32	$68	
2	proportion	2.89%	2.82%	6.02%	
3	rate of return	6.00%	6.00%	6.00%	
4	return component	0.17%	0.17%	0.36%	
5					
6	Long term debt	$704	$704	$654	
7	proportion	61.11%	61.18%	57.98%	
8	rate of return	8.67%	8.67%	8.89%	
9	return component	5.30%	5.30%	5.15%	
10					
11	Preferred shares	$0	$0	$0	
12	proportion	0.00%	0.00%	0.00%	
13	rate of return	0.00%	0.00%	0.00%	
14	return component	0.00%	0.00%	0.00%	
15					
16	Common equity	$415	$415	$406	
17	proportion	36.00%	36.00%	36.00%	
18	rate of return	9.45%	9.45%	25.0%	
19	return component	3.40%	3.40%	9.00%	
20					
21	Total capitalization	$1,153	$1,151	$1,127	
22					
23	Return on rate base	8.87%	8.87%	14.52%	
24					
25	Utility rate base	$1,153	$1,151	$1,127	Tab 2, page 1, line 20

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

NSP 2006 to Revised Mar. 9 '06
COST OF SERVICE COMPARISON
($000)

EXPENSES	NSP 2006	Revised 2006 App. Mar. 9 '06	Difference
Operating			
Labour	1,243	1,243	0
Other	1,976	2,027	(52)
Sub-total	3,218	3,270	(52)
Maintenance			
Labour	93	93	0
Other	148	148	0
Sub-total	241	241	0
Administrative and General			
Labour	0	0	0
Total Company Benefits	479	481	(2)
Other	897	901	(4)
Sub-total	1,376	1,382	(6)
Total (O, M, A & G) Excluding Co. Use	**4,835**	**4,892**	**(57)**
Transfers to Capital Operating	(187)	(187)	0
Transfers to Capital Admin. & Gen.	(200)	(201)	1
Property Taxes	815	815	0
Depreciation	1,180	1,180	0
Amortization	(158)	(159)	0
Other Income	(174)	(174)	0
2006 Settlement Allowance	(50)	0	(50)
Total Expenses Excluding Co, Use	**6,061**	**6,167**	**(105)**
Income Taxes	319	310	9
Return on Common Equity	997	997	(1)
Short Term Debt	90	91	(1)
Long Term Debt	1,319	1,319	0
Preferred Shares	1	1	0
Total Cost of Service Excluding Co. Use	**8,787**	**8,885**	**(98)**
Company Use Gas	419	721	
Total Cost of Service Including Co. Use	**9,206**	**9,606**	
2005 to 2006 Cost of Service Increase	**74**	**172**	**(98)**
2005 to 2006 Margin Decrease (Increase)	**(118)**	**(118)**	**0**
2006 Revenue (Sufficiency) Deficiency	**(44)**	**54**	**(98)**

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

NSP 2006 vs.Decision 2005
COST OF SERVICE COMPARISON
($000)

EXPENSES	NSP 2006	Decision 2005	Difference Total	Difference Subtotal
Operating				
Labour	1,243	1,149	94	
Other	1,976	1,774	201	
Sub-total	3,218	2,923	295	
Maintenance				
Labour	93	89	4	
Other	148	177	(29)	
Sub-total	241	266	(26)	
Administrative and General				
Labour	0	0	0	
Total Company Benefits	479	431	48	
Other	897	726	171	
Sub-total	1,376	1,157	219	
Total (O, M, A & G) Excluding Co. Use	**4,835**	**4,347**	**488**	**488**
Transfers to Capital Operating	(187)	(201)	14	
Transfers to Capital Admin. & Gen.	(200)	(173)	(27)	
Property Taxes	815	832	(17)	
Depreciation	1,180	1,131	50	
Amortization	(158)	4	(162)	
Other Income	(174)	(153)	(21)	
2006 Settlement Allowance	(50)	0	(50)	(212)
Total Expenses Excluding Co, Use	**6,061**	**5,785**	**276**	**276**
Income Taxes	319	452	(134)	
Return on Common Equity	997	1,041	(44)	
Short Term Debt	90	244	(154)	
Long Term Debt	1,319	1,190	130	
Preferred Shares	1	1	(0)	(202)
Total Cost of Service Excluding Co. Use	**8,787**	**8,713**	**74**	**74**
Company Use Gas	419	247		
Total Cost of Service Including Co. Use	**9,206**	**8,960**		
		2005 to 2006 Cost of Service Increase	**74**	
		2005 to 2006 Margin Decrease (Increase)	**(118)**	
		2006 Revenue Deficiency (Sufficiency)	**(44)**	

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

Bill Comparison
December 2005 to January 2006

FORT ST. JOHN AREA

Customer Classification	Annual Use	Permanent Rates Dec. 31, 2005 $ / GJ	Annual Bill Estimate $	NSP Rates Jan. 1, 2006 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	%
Residential:	128.7 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.653	84.00	0.653	84.00	0.00	
Delivery Charge		2.230	286.94	2.266	291.57	4.63	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.022	2.83	0.114	14.67	11.84	
Interim Rate Refund Rider		(0.121)	(15.57)	0.000	0.00	15.57	
			358.20		390.24	32.04	8.9%
Gas Supply Charge		9.110	1,172.22	9.600	1,235.27	63.05	
GCVA Rider		0.099	12.74	0.434	55.84	43.10	
			1,184.96		1,291.11	106.15	9.0%
		$11.993 /GJ	$1,543.16	$13.067 /GJ	$1,681.35	$138.19	9.0%
Small Commercial:	572.1 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.147	84.00	0.147	84.00	0.00	
Delivery Charge		1.994	1,140.77	2.035	1,164.22	23.45	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.022	12.59	0.114	65.22	52.63	
Interim Rate Refund Rider		(0.069)	(39.47)	0.000	0.00	39.47	
			1,197.88		1,313.44	115.56	9.6%
Gas Supply Charge		9.132	5,224.42	9.596	5,489.87	265.45	
GCVA Rider		0.099	56.64	0.434	248.29	191.65	
			5,281.06		5,738.16	457.10	8.7%
		$11.325 /GJ	$6,478.93	$12.326 /GJ	$7,051.60	$572.67	8.8%

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

Bill Comparison
December 2005 to January 2006

DAWSON CREEK AREA

Customer Classification	Annual Use	Permanent Rates Dec. 31, 2005 $ / GJ	Annual Bill Estimate $	NSP Rates Jan. 1, 2006 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	%
Residential:	120.6 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.696	84.00	0.696	84.00	0.00	
Delivery Charge		2.032	245.08	2.068	249.42	4.34	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.022	2.65	0.114	13.75	11.10	
Interim Rate Refund Rider		(0.121)	(14.59)	0.000	0.00	14.59	
			317.14		347.17	30.03	9.5%
Gas Supply Charge		9.110	1,098.74	9.600	1,157.84	59.10	
GCVA Rider		0.099	11.94	0.434	52.34	40.40	
			1,110.68		1,210.18	99.50	9.0%
		$11.838 /GJ	$1,427.82	$12.912 /GJ	$1,557.35	$129.53	9.1%
Small Commercial:	656.7 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.128	84.00	0.128	84.00	0.00	
Delivery Charge		1.457	956.81	1.498	983.74	26.92	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.022	14.45	0.114	74.86	60.42	
Interim Rate Refund Rider		(0.069)	(45.31)	0.000	0.00	45.31	
			1,009.95		1,142.60	132.65	13.1%
Gas Supply Charge		9.132	5,996.98	9.596	6,301.69	304.71	
GCVA Rider		0.099	65.01	0.434	285.01	219.99	
			6,062.00		6,586.70	524.70	8.7%
		$10.769 /GJ	$7,071.94	$11.770 /GJ	$7,729.30	$657.36	9.3%

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

Bill Comparison
December 2005 to January 2006

Customer Classification	Annual Use	Permanent Rates Dec. 31, 2005 $ / GJ	Annual Bill Estimate $	NSP Rates Jan. 1, 2006 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	%
Residential:	124.6 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.674	84.00	0.674	84.00	0.00	
Delivery Charge		2.131	265.61	2.167	270.10	4.49	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.022	2.74	0.114	14.21	11.47	
Interim Rate Refund Rider		(0.121)	(15.08)	0.000	0.00	15.08	
			337.27		368.31	31.04	9.2%
Gas Supply Charge		9.110	1,135.48	9.600	1,196.55	61.07	
GCVA Rider		0.099	12.34	0.434	54.09	41.75	
			1,147.82		1,250.64	102.82	9.0%
		$11.915 /GJ	$1,485.09	$12.989 /GJ	$1,618.95	$133.86	9.0%
Small Commercial:	614.4 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.137	84.00	0.137	84.00	0.00	
Delivery Charge		1.726	1,060.15	1.767	1,085.34	25.19	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.022	13.52	0.114	70.04	56.52	
Interim Rate Refund Rider		(0.069)	(42.39)	0.000	0.00	42.39	
			1,115.27		1,239.38	124.11	11.1%
Gas Supply Charge		9.132	5,610.70	9.596	5,895.78	285.08	
GCVA Rider		0.099	60.83	0.434	266.65	205.82	
			5,671.53		6,162.43	490.90	8.7%
		$11.046 /GJ	$6,786.80	$12.047 /GJ	$7,401.81	$615.01	9.1%

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)

Bill Comparison
January 2006 to April 2006

FORT ST. JOHN AREA

Customer Classification	Annual Use	NSP Rates Jan. 1, 2006 $ / GJ	Annual Bill Estimate $	Proposed Rates Apr. 1, 2006 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	Annual Bill Difference %
Residential:	128.7 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.653	84.00	0.653	84.00	0.00	
Delivery Charge		2.266	291.57	2.266	291.57	0.00	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.114	14.67	0.114	14.67	0.00	
Interim Rate Refund Rider		0.000	0.00	0.000	0.00	0.00	
			390.24		390.24	0.00	0.0%
Gas Supply Charge		9.600	1,235.27	8.384	1,078.80	(156.47)	
GCVA Rider		0.434	55.84	0.000	0.00	(55.84)	
			1,291.11		1,078.80	(212.31)	-16.4%
		$13.067 /GJ	$1,681.36	$11.417 /GJ	$1,469.04	($212.31)	-12.6%
Small Commercial:	572.1 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.147	84.00	0.147	84.00	0.00	
Delivery Charge		2.035	1,164.22	2.035	1,164.22	0.00	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.114	65.22	0.114	65.22	0.00	
Interim Rate Refund Rider		0.000	0.00	0.000	0.00	0.00	
			1,313.44		1,313.44	(0.00)	0.0%
Gas Supply Charge		9.596	5,489.87	8.380	4,794.20	(695.67)	
GCVA Rider		0.434	248.29	0.000	0.00	(248.29)	
			5,738.16		4,794.20	(943.96)	-16.5%
		$12.326 /GJ	$7,051.61	$10.676 /GJ	$6,107.64	($943.97)	-13.4%

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

Bill Comparison
January 2006 to April 2006

DAWSON CREEK AREA

Customer Classification	Annual Use	NSP Rates Jan. 1, 2006 $ / GJ	Annual Bill Estimate $	Proposed Rates Apr. 1, 2006 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	Annual Bill Difference %
Residential:	120.6 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.696	84.00	0.696	84.00	0.00	
Delivery Charge		2.068	249.42	2.068	249.42	0.00	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.114	13.75	0.114	13.75	0.00	
Interim Rate Refund Rider		0.000	0.00	0.000	0.00	0.00	
			347.17		347.17	0.00	0.0%
Gas Supply Charge		9.600	1,157.84	8.384	1,011.18	(146.66)	
GCVA Rider		0.434	52.34	0.000	0.00	(52.34)	
			1,210.18		1,011.18	(199.00)	-16.4%
		$12.912 /GJ	$1,557.35	$11.262 /GJ	$1,358.35	($199.00)	-12.8%
Small Commercial:	656.7 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.128	84.00	0.128	84.00	0.00	
Delivery Charge		1.498	983.74	1.498	983.74	0.00	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.114	74.86	0.114	74.86	0.00	
Interim Rate Refund Rider		0.000	0.00	0.000	0.00	0.00	
			1,142.60		1,142.60	0.00	0.0%
Gas Supply Charge		9.596	6,301.69	8.380	5,503.15	(798.55)	
GCVA Rider		0.434	285.01	0.000	0.00	(285.01)	
			6,586.70		5,503.15	(1,083.56)	-16.5%
		$11.770 /GJ	$7,729.30	$10.120 /GJ	$6,645.75	($1,083.56)	-14.0%

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

Bill Comparison
January 2006 to April 2006

Customer Classification	Annual Use	NSP Rates Jan. 1, 2006 $ / GJ	Annual Bill Estimate $	Proposed Rates Apr. 1, 2006 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	%
Residential:	124.6 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.674	84.00	0.674	84.00	0.00	
Delivery Charge		2.167	270.10	2.167	270.10	0.00	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.114	14.21	0.114	14.21	0.00	
Interim Rate Refund Rider		0.000	0.00	0.000	0.00	0.00	
			368.31		368.31	0.00	0.0%
Gas Supply Charge		9.600	1,196.55	8.384	1,044.99	(151.56)	
GCVA Rider		0.434	54.09	0.000	0.00	(54.09)	
			1,250.65		1,044.99	(205.66)	-16.4%
		$12.989 /GJ	$1,618.95	$11.339 /GJ	$1,413.30	($205.66)	-12.7%
Small Commercial:	614.4 GJ						
Monthly Fixed Charge @ 7.00 / mo.		0.137	84.00	0.137	84.00	0.00	
Delivery Charge		1.767	1,085.34	1.767	1,085.34	0.00	
GCVA Co. Use Rider		0.000	0.00	0.000	0.00	0.00	
RSAM Rider		0.114	70.04	0.114	70.04	0.00	
Interim Rate Refund Rider		0.000	0.00	0.000	0.00	0.00	
			1,239.38		1,239.38	0.00	0.0%
Gas Supply Charge		9.596	5,895.78	8.380	5,148.67	(747.11)	
GCVA Rider		0.434	266.65	0.000	0.00	(266.65)	
			6,162.43		5,148.67	(1013.76)	-16.5%
		$12.047 /GJ	$7,401.81	$10.397 /GJ	$6,388.05	($1,013.76)	-13.7%

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)

Determination of 2006 Revenue Stabilization Adjustment Mechanism (RSAM) Rider

	Residential	Small Commercial	Total
Actual RSAM Balance 12/31/04	$193,463	$248,684	$442,148
Recovery of RSAM in 2005 to 12/31/05	($33,546)	($24,873)	($58,419)
RSAM Deferral in 2005 to 12/31/05	$427,114	$217,946	$645,061
Actual RSAM Balance 12/31/05	**$587,032**	**$441,757**	**$1,028,789**
Years of Amortization	3	3	3
RSAM Balance divided by Years of Amortization equals 2006 Amortization	$195,677	$147,252	$342,930
Forecast 2006 Deliveries (GJ)	1,724,179	1,297,042	3,021,220
One Year of Amortization divided by 2006 Deliveries equals RSAM Rate Rider ($/GJ)	**0.113**	**0.114**	**0.114**

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

UTILITY INCOME & RETURN

SCHEDULE 1
(000's)

Line No.		NSP 2006	Mar. 9 '06 Update	Actual 2005	Source
1	Energy sales (TJ)	3,722	3,722	3 176	Tab Rates, page 7
2	Average rate per GJ	$11.81	$11.84	$10.18	
3					
4	Transportation service (TJ)	1,073	1,073	1 274	Tab Rates, page 7
5	Average rate per GJ	$0.81	$0.88	$0.74	
6					
7	Total deliveries (TJ)	4,795	4,795	4 450	Tab Rates, page 7
8					
9	Utility revenue				
10	Energy sales	$44,017	$44,006	$32,334	
11	Interim rates - sales	(40)	49	-	Tab Rates, page 7
12	Transportation service	872	940	937	
13	Interim rates - transportation	(4)	5	-	Tab Rates, page 7
14					
15		44,846	45,000	33,272	
16	Cost of sales	35,640	35,393	24,482	Tab Rates, page 8
17					
18	Gross margin	9,206	9,606	8,789	
19					
20	Operating expenses	3,450	3,803	3,205	Tab 1, page 2, line 6
21	Maintenance expenses	241	241	364	Tab 1, page 2, line 10
22	Admin. & general expenses	1,176	1,181	960	Tab 1, page 2, line 16
23	Property taxes, BC capital tax	815	815	832	Tab 1, page 6, line 4
24	Depreciation	1,180	1,180	1,130	Tab 2, page 3, line 49
25	Amortization	(158)	(159)	29	Tab 2, page 4, line 19
26	Investment income, other revenue	(174)	(174)	(190)	Tab 1, page 7, line 7
27	2006 Settlement Allowance	(50)		-	
28					
29		6,480	6,887	6,329	
30					
31	Earned return before income taxes	2,726	2,719	2,460	
32	Income taxes	319	310	287	Tab 3, page 1, line 14
33					
34	Earned return	$2,407	$2,409	$2,173	
35					
36	Utility rate base	$30,095	$30,119	$30,546	Tab 2, page 1, line 21
37					
38	Return on rate base	8.00%	8.00%	7.11%	Tab 5, page 1, line 23

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

UTILITY RATE BASE

SCHEDULE 2
(000's)

Line No.		NSP 2006	Mar. 9 '06 Update	Actual 2005	Source
1	Plant in service beginning of year	$57,481	$57,481	$55,528	Tab 2, page 3, line 46
2	Additions	2,284	2,285	2,143	Tab 2, page 3, line 46
3	Disposals	(121)	(121)	(191)	Tab 2, page 3, line 46
4					
5	Plant in service end of year	59,644	59,645	57,481	
6	Accumulated depreciation	22,513	22,514	21,121	Tab 2, page 5, line 43
7					
8	Net plant in service end of year	37,130	37,131	36,360	
9					
10	Net plant beginning of year	36,360	36,360	35,663	Tab 2, pages 3 & 5, lines 46 & 43
11					
12	Net plant in service midyear	36,745	36,746	36,012	
14	Contributions for construction	(7,123)	(7,123)	(7,246)	Tab 2, page 14, line 13
15	Unamortized deferred charges	630	627	620	Tab 2, page 7, line 12
16	Deferred income taxes	(553)	(553)	(553)	
17	Reserve for damages	(69)	(69)	(69)	
18	Cash working capital	252	277	1,657	Tab 2, page 8, line 10
19	Other working capital	213	213	125	Tab 2, page 13, line 15
20					
21	Utility rate base, midyear	$30,095	$30,119	$30,546	

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

INCOME TAXES

SCHEDULE 3
(000's)

Line No.		NSP 2006	Mar. 9 '06 Update	Actual 2005	Source
1	**Calculation of Taxable Income**				
2	Earned return before income taxes	$2,726	$2,719	$2,460	Tab 1, page 1, line 30
3	Interest	(1,410)	(1,411)	(1,408)	Tab 5, page 1, lines 4, 9 & 21
4	Permanent differences	8	8	8	
5	Timing differences	(496)	(514)	(410)	Tab 3, page 1, line 26
6					
7	Taxable income	$829	$802	$650	
8					
9	**Calculation of Income Tax Expense**				
10	Income taxes payable	$273	$265	$219	
11	Part I.3 tax	45	45	68	
12	Deferred income tax	0	0	-	
13					
14	Income tax expense	$319	$310	$287	
15					
16	**Particulars of Timing Differences**				
17	A. Tax Effects Subject To Flowthrough				
18	Depreciation	$1,180	$1,180	$1,130	Tab 1, page 1, line 24
19	Amortization	(158)	(159)	29	Tab 1, page 1, line 25
20	Capital cost allowance	(1,211)	(1,211)	(1,249)	
21	Deferred charges	0	0	0	
22	Overheads capitalized	(310)	(311)	(271)	
23	Other	3	(14)	(49)	
24					
25					
26	Timing differences	($496)	($514)	($410)	
27					
28	Tax rate	33.00%	33.00%	33.75%	
29	Surtax Rate	1.12%	1.12%	1.12%	
30	Deferred tax rate	33.00%	33.00%	33.75%	

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

COMMON EQUITY

SCHEDULE 4
(000's)

Line No.		NSP 2006	Mar. 9 '06 Update	Actual 2005	Source
1	Opening balance				
2	Share capital	$7,845	$7,845	$7,845	
3	Contributed surplus	0	0	-	
4	Retained earnings	3,876	3,876	3,130	
5					
6		11,721	11,721	10,975	
7					
8	Net income	921	948	765	
9	Shares issued	0	0	-	
10	Preferred dividends	(2)	(2)	-	
11	Common dividends	(2,697)	(2,704)	-	
12					
13	Closing balance	$9,944	$9,964	$11,740	
14					
15					
16	Midyear common equity	$10,833	$10,843	$11,358	

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

RETURN ON CAPITAL

SCHEDULE 5
(000's)

Line No.		NSP 2006	Mar. 9 '06 Update	Actual 2005	Source
1	Short term borrowings	$1,506	$1,522	$3,631	
2	proportion	5.00%	5.05%	11.89%	
3	rate of return	6.00%	6.00%	6.00%	
4	return component	0.30%	0.30%	0.71%	
5					
6	Long term debt	$17,739	$17,739	$15,537	
7	proportion	58.94%	58.90%	50.87%	
8	rate of return	7.44%	7.44%	7.66%	
9	return component	4.38%	4.38%	3.90%	
10					
11	Preferred shares	$16	$16	$20	
12	proportion	0.05%	0.05%	0.07%	
13	rate of return	6.48%	6.48%	6.48%	
14	return component	0.00%	0.00%	0.00%	
15					
16	Common equity	$10,834	$10,842	$11,358	
17	proportion	36.00%	36.00%	37.18%	
18	rate of return	9.20%	9.20%	6.73%	
19	return component	3.31%	3.31%	2.50%	
20					
21	Total capitalization	$30,095	$30,119	$30,546	
22					
23	Return on rate base	8.00%	8.00%	7.11%	
24					
25	Utility rate base	$30,095	$30,119	$30,546	Tab 2, page 1, line 21