

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise. This prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. These securities have not been and will not be registered under the United States Securities Act of 1933, as amended (the "US Securities Act"), or any state securities laws and may not be offered or sold in the United States. See "Plan of Distribution".

PROSPECTUS

Secondary Offering

April 6, 2005



PACIFIC NORTHERN GAS LTD.

\$25,966,454

1,338,477 Common Shares

This prospectus qualifies the distribution (the "Offering") by Tricor Acquisition (STP) Inc. (the "Selling Shareholder") of 1,338,477 common shares ("Common Shares") of Pacific Northern Gas Ltd. (the "Company") (the "Offered Shares"). The Company will not receive any part of the proceeds from the sale of the Offered Shares by the Selling Shareholder. The Offered Shares represent 37.0% of the outstanding Common Shares of the Company. Upon completion of the Offering, Tricor will have sold all of its Common Shares in the Company. See "Principal and Selling Shareholder" and "Plan of Distribution".

The offering price of the Offered Shares was determined by negotiation between Scotia Capital Inc. and CIBC World Markets Inc. (together, the "Underwriters") and the Selling Shareholder.

The Common Shares are traded on the Toronto Stock Exchange under the stock symbol "PNG". On April 5, 2005, the closing price of the Common Shares on the Toronto Stock Exchange was \$19.39 per share.

An investment in the Common Shares is subject to a number of risk factors which should be carefully reviewed by prospective purchasers. See "Risk Factors".

Price: \$19.40 per Common Share

	<u>Price to Public</u>	<u>Underwriters' Fee</u>	<u>Net Proceeds to Selling Shareholder (1)</u>
Per Common Share	\$19.40	\$0.97	\$18.43
Total	\$25,966,453.80	\$1,298,322.69	\$24,668,131.11

Note:

(1) Before deducting the expenses of the Offering, estimated to be approximately \$400,000, which will be paid by the Selling Shareholder.

The Underwriters, as principals, conditionally offer the Offered Shares, subject to prior sale, if, as and when sold and transferred by the Selling Shareholder and delivered to, and accepted by, the Underwriters in accordance with the conditions contained in the underwriting agreement referred to under "Plan of Distribution", and subject to the approval of certain legal matters on behalf of the Company by Farris, Vaughan, Wills & Murphy LLP, on behalf of the Selling Shareholder by Blake, Cassels & Graydon LLP, and on behalf of the Underwriters by Borden Ladner Gervais LLP.

Subject to applicable laws and in connection with the Offering, the Underwriters may engage in transactions that stabilize, maintain or otherwise affect the price of the Common Shares. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution".

Subscriptions for the Offered Shares will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that the closing of the offering (the "Closing") will occur on or about April 12, 2005, or such date as the Company, the Selling Shareholder and the Underwriters may agree upon, but in any event not later than May 18, 2005, and that certificates evidencing the Offered Shares will be available for delivery at the Closing.

TABLE OF CONTENTS

<p>ELIGIBILITY FOR INVESTMENT..... 2</p> <p>CERTAIN REFERENCES AND GLOSSARY 3</p> <p>NON-GAAP MEASURES 3</p> <p>FORWARD LOOKING STATEMENTS 3</p> <p>PROSPECTUS SUMMARY 4</p> <p>CORPORATE STRUCTURE 12</p> <p>BUSINESS OF PNG 12</p> <p>SELECTED CONSOLIDATED FINANCIAL AND OPERATING INFORMATION 26</p> <p>MANAGEMENT’S DISCUSSION AND ANALYSIS 27</p> <p>DIVIDENDS 32</p> <p>DESCRIPTION OF SHARE CAPITAL 32</p> <p>CONSOLIDATED CAPITALIZATION 33</p> <p>OPTIONS TO PURCHASE SECURITIES .. 34</p> <p>PRIOR SALES 35</p> <p>PRICE RANGE AND TRADING VOLUME 35</p> <p>PRINCIPAL AND SELLING SHAREHOLDER 36</p> <p>USE OF PROCEEDS 36</p> <p>DIRECTORS AND OFFICERS..... 37</p>	<p>EXECUTIVE COMPENSATION 39</p> <p>INDEBTEDNESS OF DIRECTORS AND EXECUTIVE OFFICERS 41</p> <p>PLAN OF DISTRIBUTION 42</p> <p>RISK FACTORS 43</p> <p>LEGAL PROCEEDINGS 46</p> <p>INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS..... 46</p> <p>RELATIONSHIP BETWEEN COMPANY, SELLING SHAREHOLDER AND UNDERWRITERS 46</p> <p>AUDITORS, TRANSFER AGENT AND REGISTRAR 47</p> <p>MATERIAL CONTRACTS 47</p> <p>EXPERTS 47</p> <p>PURCHASERS’ STATUTORY RIGHTS ... 47</p> <p>FINANCIAL STATEMENTS F-1</p> <p>GLOSSARY OF TERMS G-1</p> <p>CERTIFICATE OF THE COMPANY C-1</p> <p>CERTIFICATE OF THE UNDERWRITERS C-2</p> <p>AUDITORS’ CONSENT C-3</p>
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ELIGIBILITY FOR INVESTMENT

Subject to compliance with the prudent investment standards and general investment provisions and restrictions of the statutes referred to below (and, where applicable, the regulations made under those statutes) and, in certain cases, subject to the satisfaction of additional requirements relating to investment or lending policies, standards, procedures and goals and, in certain cases, subject to the filing of such policies, standards, procedures or goals, the Common Shares offered under this prospectus would not as of the date of this prospectus, be precluded as investments under the following statutes:

<p><i>Cooperative Credit Associations Act</i> (Canada);</p> <p><i>Insurance Companies Act</i> (Canada);</p> <p><i>Pension Benefits Standards Act, 1985</i> (Canada);</p> <p><i>Trust and Loan Companies Act</i> (Canada);</p> <p><i>Alberta Heritage Savings Trust Fund Act</i> (Alberta);</p> <p><i>Employment Pension Plans Act</i> (Alberta);</p> <p><i>Insurance Act</i> (Alberta);</p> <p><i>Loan and Trust Corporations Act</i> (Alberta);</p> <p><i>Financial Institutions Act</i> (British Columbia);</p> <p><i>Pension Benefits Standards Act</i> (British Columbia);</p> <p><i>The Insurance Act</i> (Manitoba);</p> <p><i>The Pension Benefits Act</i> (Manitoba);</p> <p><i>The Trustee Act</i> (Manitoba);</p>	<p><i>Pension Benefits Act</i> (Nova Scotia);</p> <p><i>Trustee Act</i> (Nova Scotia);</p> <p><i>Loan and Trust Corporations Act</i> (Ontario);</p> <p><i>Pension Benefits Act</i> (Ontario);</p> <p><i>Trustee Act</i> (Ontario);</p> <p><i>An Act respecting insurance</i> (Québec) (in respect of insurers other than guarantee funds);</p> <p><i>An Act respecting trust companies and savings companies</i> (Québec) (for a trust company investing its own funds and deposits it receives and a savings company investing its funds);</p> <p><i>Supplemental Pension Plans Act</i> (Québec); and</p> <p><i>The Pension Benefits Act, 1992</i> (Saskatchewan).</p>
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In the opinion of Farris, Vaughan, Wills & Murphy LLP, counsel to the Company, and of Borden Ladner Gervais LLP, counsel to the Underwriters, the Common Shares are qualified investments for a trust governed by a registered retirement savings plan, a registered retirement income fund, a registered education savings plan or a deferred profit sharing plan under the *Income Tax Act* (Canada) and the regulations made under that act (the “Tax Act”). In addition, in the opinion of such counsel, the Common Shares would not as of the date of this prospectus constitute “foreign property” for the purposes of Part XI of the Tax Act.

CERTAIN REFERENCES AND GLOSSARY

In this prospectus, unless the context otherwise requires, the “Company” refers to Pacific Northern Gas Ltd., “PNG(NE)” refers to Pacific Northern Gas (N.E.) Ltd., and “PNG” refers to the Company and its subsidiaries, including PNG(NE).

Measurement of natural gas is expressed in both energy and volume units in this prospectus. In the case of energy, the basic unit is the gigajoule (“GJ”), which is equivalent to 947,817 British thermal units. A terajoule (“TJ”) is 1,000 gigajoules, and a petajoule (“PJ”) is 1,000,000 gigajoules. In the case of volume, both metric and imperial measures are used. The metric measure is one thousand cubic metres (“10³m³”), and the imperial measures are 1,000 cubic feet (“Mcf”) and 1,000,000 cubic feet (“MMcf”). One 10³m³ is equivalent to 35.30 Mcf.

The “Glossary of Terms” at page G-1 of this prospectus contains definitions of terms used in this prospectus.

NON-GAAP MEASURES

References to “EBITDA” are to earnings before interest, income taxes, depreciation and amortization and references to “operating margin” are to operating revenues less cost of sales. EBITDA and operating margin are not measures recognized by generally accepted accounting principles in Canada (“GAAP”) and do not have a standardized meaning prescribed by GAAP. Potential investors are cautioned that EBITDA should not replace net earnings or loss (as determined in accordance with GAAP) as an indicator of the Company’s performance, or cash flows from operating, investing and financing activities as a measure of the Company’s liquidity and cash flows, and that operating margin should not replace revenues as a measure of activity. The Company’s method of calculating EBITDA and operating margin may differ from the methods used by other issuers. Therefore, the Company’s EBITDA and operating margin may not be comparable to similar measures presented by other issuers. See “Management’s Discussion and Analysis — Liquidity — Financial Ratios” for a reconciliation of EBITDA to amounts reported in the consolidated financial statements of the Company.

EBITDA is used by management to determine the Company’s internally generated cash flow that is available to service indebtedness, fund capital expenditures and pay cash income taxes. Accordingly, management believes EBITDA is a useful measure for prospective investors in evaluating the financial health of the Company, and specifically, the ability of the Company to service the interest on its indebtedness. As a regulated utility, the Company purchases gas for resale without mark-up to residential and certain commercial and industrial customers, whereas certain commercial and many industrial customers arrange for their own gas supply and contract with the Company for transportation of that gas. As operating margin excludes the cost of sales, being the cost of gas resold to customers without mark-up, management uses operating margin to provide better comparability of revenue contribution by the Company’s gas transportation customers and gas sales customers. Accordingly, management believes operating margin is a useful supplemental measure that may assist prospective investors in evaluating the Company’s revenue performance.

FORWARD LOOKING STATEMENTS

This prospectus contains certain forward looking statements. These statements relate to future events or future performance and reflect management’s expectations regarding the Company’s growth, results of operations, performance and business prospects and opportunities or industry performance and trends. These forward looking statements reflect management’s current internal projections, expectations or beliefs and are based on information currently available to the Company. In some cases, forward looking statements can be identified by terminology such as “may”, “will”, “should”, “expect”, “plan”, “anticipate”, “believe”, “estimate”, “predict”, “potential”, “continue”, “project” or the negative of these terms or other comparable terminology. A number of factors could cause actual events or results to differ materially from the results discussed in the forward looking statements. In evaluating these statements, prospective investors should specifically consider the risks and uncertainties discussed under “Risk Factors” and elsewhere in this prospectus. Actual results may differ materially from any forward looking statement. Although management believes that the forward looking statements contained in this prospectus are based upon reasonable assumptions, prospective investors cannot be assured that actual results will be consistent with these forward looking statements. These forward looking statements are made as of the date of this prospectus, and the Company assumes no obligation to update or revise them to reflect new events or circumstances.

PROSPECTUS SUMMARY

The following is a summary of the principal features of the Offering and should be read together with the more detailed information and financial data and statements contained elsewhere in this prospectus. Certain terms used in this summary are defined in the Glossary of Terms.

Pacific Northern Gas

PNG owns and operates a natural gas transmission and distribution utility in the west-central portion of northern British Columbia. PNG also owns and operates a natural gas distribution utility in the northeast portion of British Columbia. The utilities are separate stand-alone systems and both are regulated by the BCUC.

PNG supplies gas to approximately 39,300 residential, commercial and industrial customers. Gas distributed by PNG to its residential and commercial customers and to certain industrial customers is purchased under various agreements with gas producers and other suppliers. Most of PNG's industrial customers satisfy their gas requirements by purchasing gas directly from producers or other suppliers and contracting with PNG for the transportation of that gas through PNG's pipeline systems. Accordingly, all of the firm gas requirements of PNG's large industrial customers and approximately three-quarters of the firm gas requirements of PNG's small industrial customers are met through direct gas supply arrangements. Since PNG earns income from the transportation and distribution of gas and not from the sale of gas as a commodity, it is not adversely affected by direct gas supply arrangements entered into by its customers.

PNG has four large industrial customers: Methanex, West Fraser, Alcan and BC Hydro. These four customers accounted for 75% of total gas deliveries and 33% of PNG's operating margin during 2004.

PNG's natural gas distribution business is seasonal, with higher sales in the colder winter months and lower sales in warmer months because a substantial portion of the gas it delivers is used for space heating purposes. As a result, PNG earns the majority of its net income in the first and fourth quarters of its fiscal year and generally incurs losses in the other two quarters.

Western Region

Transmission Pipeline System

PNG's transmission pipeline system in the Western region extends 587 kilometres from Summit Lake, near Prince George, to the west coast of British Columbia at Prince Rupert. PNG also owns and operates over 300 kilometres of lateral transmission pipelines extending into the various communities served by PNG, the most significant being dual lines extending approximately 57 kilometres into Kitimat.

Distribution System and Franchise Agreements

PNG owns and operates natural gas distribution facilities to deliver gas from its transmission pipeline system to homes and businesses in the various communities located throughout the Western region. The Company currently has exclusive franchise agreements with the municipalities of Prince Rupert, Port Edward, Kitimat, Terrace, Smithers, Burns Lake, Houston and Vanderhoof, entitling it to supply and distribute natural gas within those municipalities. The customers in these municipalities represent approximately 75% of all customers in the Western region. PNG also has operating agreements with the municipalities of Fort St. James and Telkwa that entitle it to install and operate gas distribution facilities in those municipalities. Under each of the municipal franchise and operating agreements, PNG is required to pay the municipality an annual fee based on gas sales.

The communities served by PNG's distribution system within its Western region had a total population of approximately 77,000 at December 31, 2004.

Northeast Region

Transmission and Distribution Facilities

PNG's pipeline system in the Northeast region serves the Fort St. John, Dawson Creek and Tumbler Ridge areas. PNG's entire system in the Northeast region consists of approximately 160 kilometres of transmission lines, 1,490 kilometres of distribution lines and a gas processing plant near Tumbler Ridge with a capacity of approximately 120 10³m³ per day.

Franchise Agreements

PNG has exclusive franchise agreements with the cities of Dawson Creek and Fort St. John, as well as an operating agreement with the Village of Pouce Coupe. The agreements provide for payment of a fee based on gross revenues from sales of gas to residential, commercial, public, institutional and industrial customers. PNG operates its gas distribution facilities in the Tumbler Ridge area pursuant to a certificate of public convenience and necessity issued by the BCUC. No franchise fees are payable to the municipality of Tumbler Ridge.

The communities served by PNG's distribution system in its Northeast region had a total population of approximately 47,000 at December 31, 2004.

Properties

Substantially all of PNG's transmission lines, including lateral transmission lines, are located across Crown land or privately owned property under rights-of-way granted by the Crown or the owners in perpetuity or for so long as they are used for pipeline purposes. Compressor and metering stations are principally located on land owned by PNG in fee simple. PNG owns its local offices in Terrace, Prince Rupert, Kitimat, Burns Lake, Smithers, Dawson Creek, Tumbler Ridge and Fort St. John and leases office space in a number of other communities in its service area and in Vancouver.

Gas Deliveries and Customers

The following table sets out, by customer category, certain information relating to PNG's gas sales and deliveries for the past three years:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
Deliveries (in TJ):			
Residential	3 279	3 464	3 503
Commercial	2 715	2 909	2 967
Small industrial	3 736	3 589	3 805
Large industrial	<u>29 241</u>	<u>26 676</u>	<u>29 188</u>
Total energy delivered	<u>38 971</u>	<u>36 638</u>	<u>39 463</u>
Customers at Year End:			
Residential	34,242	34,078	34,251
Commercial	4,993	4,978	4,941
Small industrial	52	46	58
Large industrial	<u>4</u>	<u>4</u>	<u>4</u>
Total number of customers	<u>39,291</u>	<u>39,106</u>	<u>39,254</u>

Large Industrial Customers

Overview

The Company has transportation service agreements with Methanex, West Fraser and Alcan. The Company delivers gas to its other large industrial customer, BC Hydro, under an interruptible sales and service agreement for standby power generation at BC Hydro's facility in Prince Rupert.

Methanex

The Company provides firm gas transportation service to Methanex's methanol/ammonia complex in Kitimat. The agreement specifies a daily contract demand volume and a minimum monthly charge equal to 100% of the monthly contract demand volume at the firm toll. Deliveries to Methanex in 2004 accounted for approximately 67% of the volumes delivered by PNG and approximately 25% of PNG's operating margin.

The agreement with Methanex expires in October 2009, but Methanex may terminate its obligations under the agreement with six months' notice and payment of a buy-out amount to the Company on the effective date of the termination. The buy-out payment is approximately equal to the net present value of future firm contract payment obligations, net of the Company's avoidable costs if Methanex were no longer operating. The Company considers that there is a significant risk that Methanex will terminate the agreement in accordance with its terms prior to its

expiry, in connection with divesting the methanol/ammonia complex or otherwise, or not renew the agreement when it expires in October 2009. See “Risk Factors”.

West Fraser

The Company provides firm gas transportation service to West Fraser’s linerboard and kraft paper mill in Kitimat. The agreement specifies a daily contract demand volume and a minimum monthly charge equal to 100% of the monthly contract demand volume at the firm toll. During 2004, deliveries to West Fraser accounted for approximately 6% of the Company’s total gas deliveries and 5% of operating margin.

The agreement with West Fraser expires in December 2013, but West Fraser may terminate its obligations under the agreement with six months’ notice and payment of a buy-out payment to the Company on the effective date of the termination. In addition, West Fraser may terminate the agreement effective January 1, 2009 without a buy-out payment if it has permanently shut down or commenced the permanent shut down of the Kitimat mill by January 1, 2009. West Fraser’s obligation to pay the minimum monthly charge will continue in effect until the Kitimat mill is permanently shut down. If the permanent shut down is not completed by December 31, 2009, then the agreement will continue in force until the original expiry date of December 31, 2013.

Alcan

PNG provides firm gas transportation service to Alcan’s Kitimat aluminum facility. The agreement specifies a daily contract demand volume and a minimum monthly charge equal to 85% of the monthly contract demand volume at the firm toll. The initial term of the agreement ended November 1, 2004, but the agreement automatically continues in effect from contract year to contract year unless either party gives 12 months’ notice of termination. During 2004, deliveries to Alcan accounted for 3% of the Company’s total gas deliveries and 3% percent of operating margin. Alcan has produced aluminum for export from its Kitimat facility since 1952.

BC Hydro

The Company delivers gas to BC Hydro under an interruptible sales and service agreement for electric power generation at BC Hydro’s facility in Prince Rupert. This facility has typically been used by BC Hydro as a stand-by facility. Deliveries in 2004, utilized to maintain the facility in a ready to operate mode, represented approximately 0.1% of the Company’s operating margin.

Natural Gas Supply

All of PNG’s residential customers, most of its commercial customers and a number of its smaller industrial customers continue to rely on PNG for arrangement of their gas supply, and pay rates which include PNG’s gas supply commodity and delivery costs. The commodity cost of gas is passed through to customers in rates and subsequent rate adjustments, after approval by the BCUC. PNG’s large industrial customers, the majority of its small industrial customers, and a few large commercial customers arrange for delivery of their gas supply requirements to PNG. These customers contract for gas transportation service on PNG’s pipeline systems. Some of these customers also purchase gas from PNG to supplement their gas supply as may be required from time to time and subject to gas supply availability from PNG.

To meet the requirements of its gas sales customers, natural gas is purchased by PNG under various gas purchase contracts. Contracted gas that is surplus to the requirements of these customers may either be sold on an interruptible basis to industrial customers or be sold to other purchasers.

Government Regulation

General

PNG is subject to regulation by the BCUC under the Utilities Act. The BCUC regulates the business of public utilities, including the construction and operation of major facilities, the issuance of securities, determination of rates for the sale and transportation of gas and the terms and conditions of service. In approving rates, the BCUC must determine that such rates reflect a fair and reasonable charge for service of the nature and quality furnished by PNG to its customers, and that such rates are sufficient to yield PNG a fair and reasonable compensation for its services, including a fair and reasonable return upon the value of its property. PNG is also subject to regulation under the *Pipeline Act* (British Columbia) in respect of the construction, operation and maintenance of its transmission pipeline facilities.

Rate Regulation

PNG’s rates are determined by the BCUC on a fixed rate method, under which rates are set on the basis of annual forecasts of both the cost of service and throughput for PNG’s transmission and distribution systems.

A key component of the rate determination is cost of capital, including the after-tax return on the common equity component of the capital structure (the “ROE”). The BCUC uses a formula to determine, on an annual basis, the ROE applicable to a low risk benchmark utility based on forecast long term Government of Canada bond rates, plus 350 basis points. PNG’s risk profile is compared by the BCUC to the low risk benchmark utility to determine PNG’s utility-specific risk premium relative to the ROE applicable to the low risk benchmark utility.

The BCUC has approved a number of deferral accounts for PNG to record costs and revenues for various items for recovery from customers, or refund to customers, over a future time period. The general purpose of a deferral account is to keep PNG or its customers whole in respect of the subject matter of the deferral account. The two main deferral accounts (which apply to all divisions of PNG) are the gas cost variance account (or “GCVA”), which reconciles forecast gas costs to actual gas costs incurred over time, and the rate stabilization adjustment mechanism (or “RSAM”), which reconciles forecast gas consumption by residential and small commercial customers to actual gas consumption over time.

Revenue requirements applications for PNG’s three service areas (the Western region, the Fort St. John/Dawson Creek division and the Tumbler Ridge division) are submitted to the BCUC, generally on an annual basis. The BCUC may consider these applications through a public hearing process (either oral or written), or through negotiations with the customers under alternate dispute resolution processes.

The following table summarizes, for each of PNG’s three service areas, the rate base, common equity component of rate base and after-tax rate of return on common equity approved by the BCUC for the three years ended December 31, 2004:

	<u>Year ended December 31,</u>		
	<u>2004</u>	<u>2003</u>	<u>2002</u>
	(Dollar amounts in thousands)		
Western region:			
Rate base	\$135,488	\$136,037	\$136,983
Common equity component	36.0%	36.0%	36.0%
Allowed return on common equity	9.80%	10.17%	9.88%
Fort St. John/Dawson Creek division:			
Rate base	\$ 30,521	\$ 28,219	\$ 26,281
Common equity component	36.0%	36.0%	36.0%
Allowed return on common equity	9.55%	9.82%	9.63%
Tumbler Ridge division:			
Rate base	\$ 1,043	\$ 1,166	\$ 1,180
Common equity component	36.0%	36.0%	36.0%
Allowed return on common equity	9.80%	10.07%	9.88%

In November 2004, the BCUC confirmed that the allowable return on common equity for 2005 will be 9.68% for the Western region, 9.43% for the Fort St. John/Dawson Creek division and 9.68% for the Tumbler Ridge division.

In December 2004, PNG filed revenue requirements applications with the BCUC for the Western region, the Fort St. John/Dawson Creek division and the Tumbler Ridge division. The applications are currently under review by the BCUC.

Application to the BCUC to Convert to an Income Trust Structure

In January 2004 PNG filed an application with the BCUC seeking approval to convert to an income trust ownership structure. The decision to apply for such approval was primarily based on the fact that the significance of Methanex as a customer (accounting for approximately 25% of PNG’s operating margin in 2004), coupled with the fact that the Methanex contract expires in 2009 and can be terminated by Methanex before that date, has precluded access by PNG to traditional institutional lenders as a source of long term debt. PNG is accordingly relying on

operating cash flow to fund capital expenditures and amortization of long term debt. PNG has significant near and medium term needs to access capital markets. In particular, PNG needs to access long term debt markets to refinance its maturing long term debt. Over the next ten years PNG must refinance approximately \$46 million of long term debt, including \$4.4 million of debt in 2005 and \$4.9 million per year over the four year period from 2006 to 2009, inclusive.

Given these circumstances, PNG concluded in early 2003 that reorganizing its business under an income trust ownership structure would be the best means of addressing PNG's capital requirements on a long term basis. Company believes one of the primary advantages of the income trust structure is that it would allow PNG to reduce its long term secured debt significantly, and replace that debt with long term subordinate debt advanced to PNG by the income trust using proceeds from an initial public offering of trust units. This would improve PNG's financial flexibility and access to capital without PNG having to increase rates to its customers.

On July 29, 2004 the BCUC issued a decision denying PNG's initial application to convert to an income trust structure, citing concerns over the requirement to deem a common equity component higher than the proposed income trust's level of equity, as well as requirements to deem income tax expenses for rate making purposes.

PNG reviewed the BCUC decision and concluded the BCUC's concerns could be addressed in a new application. In December 2004, PNG filed a new application with the BCUC for approval to convert to an income trust structure. The Company believes the new application addresses the concerns raised by the BCUC in its denial of the first application. In particular, the new application requests that the BCUC set customer rates using the actual capital structure of the proposed income trust rather than a deemed capital structure.

An oral public hearing on PNG's application is scheduled to commence on May 10, 2005.

In addition to approval by the BCUC, the conversion to an income trust structure will require approval of a plan of arrangement by PNG's shareholders and the court, and agreement with PNG's debentureholders to allow PNG to redeem approximately \$40 million of its outstanding debentures on acceptable terms and conditions.

The plan of arrangement is expected to be conditional upon the completion by the proposed income trust of an initial public offering of units, the proceeds of which would be used to redeem a portion of the outstanding debentures and all of the Preferred Shares, and to pay conversion and transaction expenses. PNG can give no assurances that the required approvals will be obtained, that there will be acceptable market conditions for the proposed income trust's initial public offering or that the conversion by PNG to an income trust structure will be completed. See "Business of PNG — Application to BCUC to Convert the Company to an Income Trust Structure" and "Risk Factors".

Trends and Competition

As a regulated utility, PNG does not face competition from other natural gas transmission and distribution companies. PNG does, however, compete with other energy sources in meeting the needs of energy consumers in its service areas. The main sources of competition are from electricity and wood in the residential sector, electricity in the commercial sector and wood waste in the industrial forestry sector.

PNG has experienced reductions in average gas consumption per residential and commercial customer. PNG believes that only a small portion of the reduction in average gas consumption has resulted from substitution of other fuels for natural gas, with the main reason for the reduction in average gas consumption being conservation measures undertaken by consumers in response to higher natural gas prices and poor economic conditions experienced in the Western region. Gas consumption by small industrial customers in the Western region has also declined through conservation and substitution of wood waste for natural gas.

In addition to the effect of the conservation and substitution of energy sources, PNG experienced a net loss in the number of residential customers from 2001 through 2003, with 2004 remaining flat relative to 2003. The poor economic conditions in the Western region are believed to be responsible for the majority of the decline in the number of residential customers. Certain small industrial customers have also closed down, contributing to reduced economic activity in the Western region and the decline in gas consumption in the small industrial sector.

These recent trends are not necessarily indicative of future trends. Management of PNG expects there to be a limit to the conservation measures that can be undertaken by residential, commercial and industrial customers.

Further, there are a number of initiatives and prospects in PNG's Western region that could have a positive impact on the economic conditions in this service area, including:

- development of a container handling facility at the Port of Prince Rupert;
- construction of a proposed oil pipeline from Alberta to tidewater at either Kitimat or Prince Rupert; and
- separate proposals for liquefied natural gas ("LNG") import and regasification facilities at Prince Rupert and Kitimat.

The proponent of the proposed LNG facility in Kitimat, Kitimat LNG Terminal, has commenced the process to obtain a Project Approval Certificate from the British Columbia Environmental Assessment Office and the Canadian Environmental Assessment Agency, and has indicated its desire to utilize PNG's natural gas transportation services to deliver the regasified LNG into the Duke Energy Gas Transmission system at the point of the existing interconnection with PNG. PNG would be required to reverse the flow of its pipeline and expand capacity in the event the Kitimat LNG project proceeds as planned.

In PNG's Northeast region there has been recent growth in the oil and gas sector, as well as the coal sector, which may expand PNG's customer base in that region.

Selected Financial and Operating Information

The following selected financial information has been derived from the consolidated financial statements of the Company appearing elsewhere in this prospectus, and should be read in conjunction with these financial statements, the related notes, and “Management’s Discussion and Analysis”.

	Year Ended December 31,		
	2004	2003	2002
	(Dollar amounts in thousands, except per share data)		
Statement of Income Information:			
Operating revenues	\$137,755	\$133,727	\$109,063
Operating margin (1)	48,801	49,310	52,243
Net income	5,408	5,668	4,590
Basic earnings per Common Share	\$ 1.41	\$ 1.49	\$ 1.20
Diluted earnings per Common Share	1.38	1.46	1.18
Dividends paid per Common Share	0.80	3.55	—
Dividends paid per Preferred Share	1.69	1.69	1.69
Balance Sheet Information:			
Total assets	\$207,657	\$206,414	
Total long term financial liabilities	97,284	101,481	
Preferred shares	5,000	5,000	
Common shareholders’ equity (2)	73,950	71,522	
Common shareholders’ equity (2) per share	20.52	19.96	
Other Financial Information:			
EBITDA (1)	26,182	26,913	28,870
Ratio of EBITDA (1) to interest expense	3.27	3.32	3.75
Selected Operating Information:			
Deliveries (TJ):			
Sales	7 338	7 754	8 045
Transportation service	<u>31 633</u>	<u>28 884</u>	<u>31 418</u>
Total	<u>38 971</u>	<u>36 638</u>	<u>39 463</u>
Customers at period end	39,291	39,106	39,254
Weighted average cost of gas purchased (per GJ)	\$ 6.42	\$ 6.59	\$ 4.11

Notes:

- (1) EBITDA and operating margin are not recognized measures under GAAP and do not have standardized meanings prescribed by GAAP. Therefore, EBITDA and operating margin may not be comparable to similar measures presented by other issuers. See “Non-GAAP Measures”.
- (2) Common shareholders’ equity is comprised of common share capital, contributed surplus and retained earnings.

Summary of the Offering

Offering by the Selling Shareholder:

1,338,477 Common Shares. See “Principal and Selling Shareholder”.

Amount:

\$25,966,453.80.

Price:

\$19.40 per Common Share.

Use of Proceeds:

The net proceeds to the Selling Shareholder from the Offering will be approximately \$24,268,130, after deducting the estimated expenses of the Offering and the Underwriters’ fee. The Company will not receive any part of the proceeds from the sale of the Offered Shares by the Selling Shareholder. See “Use of Proceeds”.

Dividends:

Over the last two years the Company has paid regular quarterly cash dividends of \$0.20 per Common Share on March 23, June 23, September 23 and December 23 of each year. The record date for the March 23, 2005 dividend on the Common Shares was March 4, 2005, and accordingly purchasers of the Offered Shares will not be entitled to this dividend. The declaration and payment of dividends are subject to the discretion of the Company’s board of directors and depend on, among other things, the Company’s financial condition, general business conditions and other factors which the Company’s board of directors considers to be relevant. See “Dividends”.

Voting at Annual Meeting:

The Company’s annual general meeting will be held on April 28, 2005, and the record date for that meeting is March 18, 2005. As the Offering will not be completed until after the record date, purchasers of the Offered Shares will not be entitled to vote those shares at the meeting or any adjournment thereof. The Selling Shareholder will have the legal right to vote the Offered Shares at the meeting but has agreed in the Underwriting Agreement not to vote any Offered Shares sold prior to the meeting. See “Plan of Distribution”.

Risk Factors:

An investment in the Common Shares is subject to a number of risk factors. Prospective investors should carefully consider the following risks before making an investment decision: potential for termination of large industrial contracts; the risk of not obtaining BCUC or other required approvals to convert PNG into an income trust structure or PNG’s inability to convert to an income trust structure for other reasons; liquidity, cash flow and capital availability risks; commodity price and supply risks; usage risks; regulatory risks; facility and insurance risks; environmental and safety risks; derivatives risks; human resources risks; aboriginal matters; and share price volatility. Prospective investors should also refer to the other information in this prospectus, including the Company’s consolidated financial statements and the related notes. The risks and uncertainties described above are not the only risks and uncertainties the Company faces. Additional risks and uncertainties not currently known to the Company or that the Company currently deems immaterial also may impair the Company’s business operations. If any of the above risks actually occur, the Company’s business, results of operations and financial condition could suffer. In that event, the trading price of the Common Shares could decline, and an investor may lose all or part of his or her investment in the Common Shares. See “Risk Factors”.

CORPORATE STRUCTURE

Pacific Northern Gas Ltd. was incorporated under the laws of the Province of British Columbia on October 28, 1965. The head office and registered office of the Company is located at Suite 950, 1185 West Georgia Street, Vancouver, British Columbia.

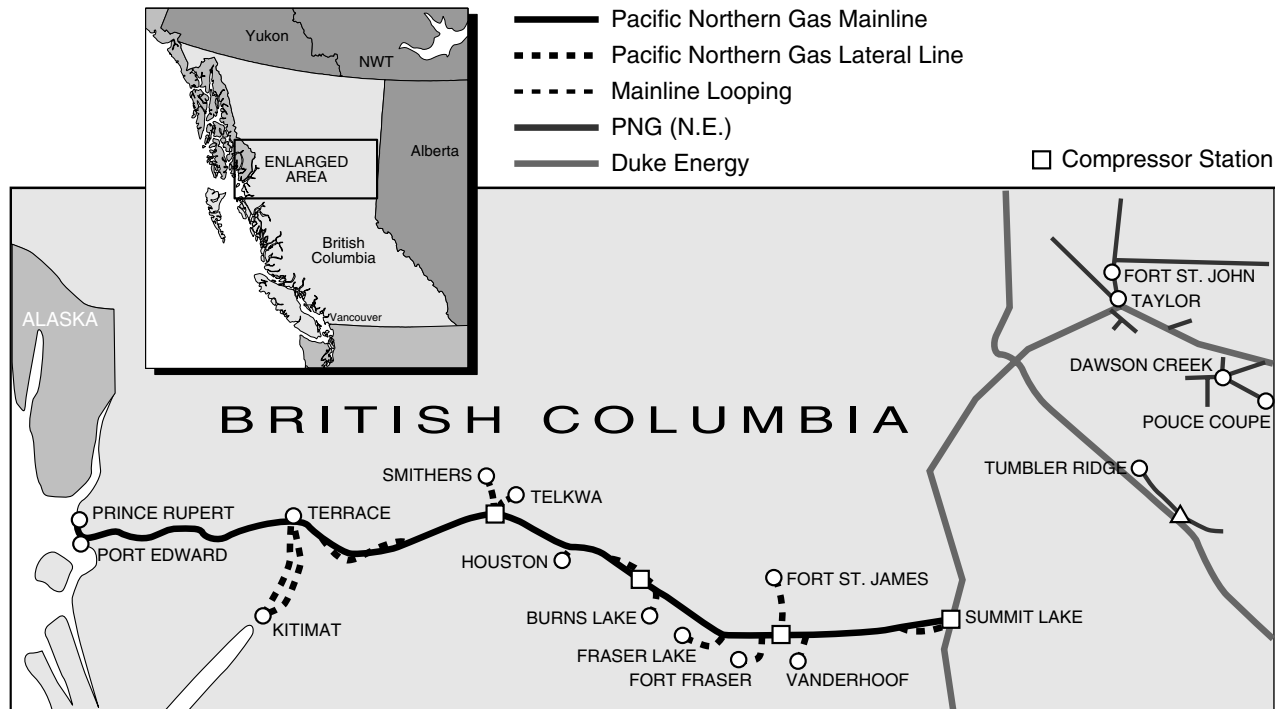
Pacific Northern Gas (N.E.) Ltd. (“PNG(NE)”) was formed under the laws of the Province of British Columbia on June 30, 1999 by the amalgamation of Pacific Northern Gas (N.E.) Ltd., Centra Gas Fort St. John Inc. and Peace River Transmission Company Limited, and is a wholly owned subsidiary of the Company. PNG Marketing Ltd. (currently inactive) was incorporated under the laws of the Province of British Columbia on October 17, 1986 and is a wholly owned subsidiary of the Company. Pacific Northern Gas Transition Ltd. (currently inactive) was incorporated under the laws of the Province of British Columbia on January 28, 2004 and is a wholly owned subsidiary of the Company.

BUSINESS OF PNG

Overview

The Company owns and operates a natural gas transmission and distribution utility in the west-central portion of northern British Columbia (the “Western region”). Through PNG(NE), the Company also owns and operates a natural gas distribution utility in the northeast portion of British Columbia (the “Northeast region”). The utilities are separate stand-alone systems and both are regulated by the British Columbia Utilities Commission (the “BCUC”).

PNG’s Western region extends from Summit Lake to Prince Rupert and Kitimat. The Northeast region includes Tumbler Ridge, Dawson Creek, Fort St. John and the surrounding areas. PNG also operates a small propane vapour distribution system in Granisle, British Columbia.



PNG supplies gas to approximately 39,300 residential, commercial and industrial customers. PNG has four large industrial customers: Methanex Corporation (“Methanex”), West Fraser Mills Ltd. (“West Fraser”), Alcan Smelters and Chemicals Ltd. (“Alcan”) and British Columbia Hydro and Power Authority (“BC Hydro”). These four customers accounted for 75% of total gas deliveries and 33% of PNG’s operating margin during 2004.

PNG’s combined rate base for 2004, as approved by the BCUC, was approximately \$167 million.

Gas distributed by PNG to its residential and commercial customers and to certain industrial customers in 2004 was purchased under various agreements with gas producers and other suppliers. Most of PNG's industrial customers satisfy their gas requirements by purchasing gas directly from producers or other suppliers and contracting with PNG for the transportation of that gas through PNG's pipeline systems. Accordingly, all of the firm gas requirements of PNG's large industrial customers and approximately three-quarters of the firm gas requirements of PNG's small industrial customers are met through direct gas supply arrangements. Since PNG earns income from the transportation and distribution of gas and not from the sale of gas as a commodity, it is not adversely affected by direct gas supply arrangements entered into by its customers.

PNG's natural gas distribution business is seasonal, with higher sales in the colder winter months and lower sales in warmer months because a substantial portion of the gas it delivers is used for space heating purposes. As a result, PNG earns the majority of its net income in the first and fourth quarters of its fiscal year and generally incurs losses in the other two quarters.

Western Region

Transmission Pipeline System

PNG's transmission pipeline system in the Western region connects with the British Columbia pipeline system operated by Westcoast Energy Inc., doing business as Duke Energy Gas Transmission ("Duke Energy"), near Summit Lake, British Columbia, and extends 587 kilometres to the west coast of British Columbia at Prince Rupert. The pipeline between Summit Lake and Terrace has been partially paralleled, or looped, with a second line to increase throughput capacity. PNG also owns and operates over 300 kilometres of lateral transmission pipelines extending into the various communities served by PNG, the most significant being dual lines extending approximately 57 kilometres into Kitimat.

Five compressor units maintain pressure on PNG's transmission pipeline system: two located at Summit Lake and one each at Vanderhoof, Burns Lake and Telkwa. The total installed rating of the compressor units is 16,120 kilowatts (21,610 horsepower). The sustainable capacity of the transmission pipeline system, with the present compressor and looping configuration, is approximately $3\ 260\ 10^3\text{m}^3$ (115 MMcf) per day.

Distribution System and Franchise Agreements

PNG owns and operates natural gas distribution facilities to deliver gas from its transmission pipeline system to homes and businesses in the various communities located throughout the Western region. PNG's Western region distribution system is comprised of approximately 1,180 kilometres of distribution pipelines.

PNG currently has exclusive franchise agreements with the municipalities of Prince Rupert, Port Edward, Kitimat, Terrace, Smithers, Burns Lake, Houston and Vanderhoof, entitling it to supply and distribute natural gas within those municipalities. The customers in these municipalities represent approximately 75% of all customers in the Western region. Each of the franchise agreements has an initial term of 21 years, expiring in 2011 (except in the case of Port Edward, where the agreement expires in 2010, and Prince Rupert, where the agreement expires in 2015), and is renewable at the option of either party for a further term of 21 years.

PNG also has operating agreements with the municipalities of Fort St. James and Telkwa that entitle it to install and operate gas distribution facilities in those municipalities. The initial term of each of these operating agreements has expired, and PNG is operating within ten year renewal terms which expire in 2009 and 2011, respectively. Each operating agreement provides for an unlimited number of ten year renewal terms, which take effect automatically on the expiry of the preceding renewal term. If the parties cannot agree on alterations to an operating agreement for a renewal term, the BCUC may determine such alterations. In the Village of Fraser Lake, PNG is operating under a franchise agreement which PNG is proceeding to file for approval with the BCUC.

Under all of the municipal franchise and operating agreements, PNG is required to pay the municipality an annual fee on gas sales within the municipality equal to 3% of PNG's gross revenue from sales to residential and commercial customers and 3% of the gross revenue from the sale of the first 328,000 GJ (approximately 300 MMcf) per year to any industrial customer.

The communities served by PNG's distribution system within its Western region had a total population of approximately 77,000 at December 31, 2004.

Northeast Region

Transmission and Distribution Facilities

PNG's pipeline system in the Northeast region serves the Fort St. John and Dawson Creek area through connections with the Duke Energy pipeline system at several locations. PNG's system also connects with a pipeline owned by Canadian Natural Resources Limited ("CNRL") in two locations to obtain supply for the Fort St. John area, and with a producer's pipeline and the Duke Energy pipeline system near Chetwynd to serve the Tumbler Ridge area. PNG's entire system in the Northeast region consists of approximately 160 kilometres of transmission lines, 1,490 kilometres of distribution lines and a gas processing plant near Tumbler Ridge with a capacity of approximately 120 10³m³ per day.

Franchise Agreements

PNG has exclusive franchise agreements with the cities of Dawson Creek and Fort St. John for 21-year terms, expiring in 2014 and 2018, respectively, as well as an operating agreement with the Village of Pouce Coupe which expires in 2016. The agreements provide for payment of a 3% fee on gross revenues from sales of gas to residential, commercial, public and institutional customers and 3% of the gross revenue from the sale of the first 328,000 GJ per year to any industrial customer. PNG operates its gas distribution facilities in the Tumbler Ridge area pursuant to a certificate of public convenience and necessity issued by the BCUC. No franchise fees are payable to the municipality of Tumbler Ridge.

The franchise agreement with the City of Dawson Creek and the operating agreement with the Village of Pouce Coupe are renewable for a further term of 21 years at the option of either party. The franchise agreement with the City of Fort St. John gives the municipality the right to purchase the distribution system within the municipality on expiry of the franchise agreement at the fair market value of the assets as a going concern.

The communities served by PNG's distribution system in its Northeast region had a total population of approximately 47,000 at December 31, 2004.

Properties

Substantially all of PNG's transmission lines, including lateral transmission lines, are located across Crown land or privately owned property under rights-of-way granted by the Crown or the owners in perpetuity or for so long as they are used for pipeline purposes. Approximately three kilometres of main pipelines and approximately nine kilometres of lateral transmission pipelines cross reserves established under the *Indian Act* (Canada), for which PNG has appropriate land rights. Within all the municipalities in which PNG distributes gas, distribution lines occupy municipal streets and lanes by authority granted to PNG under franchise or operating agreements or other regulatory approvals. River, highway and railway crossings have generally been constructed pursuant to orders or permits from appropriate authorities or owners. Compressor and metering stations are principally located on land owned by PNG in fee simple. PNG owns its local offices in Terrace, Prince Rupert, Kitimat, Burns Lake, Smithers, Dawson Creek, Tumbler Ridge and Fort St. John and leases office space in a number of other communities in its service area and in Vancouver.

All of the property and assets of the Company and PNG(NE) are subject to the lien of a deed of trust and mortgage dated as of April 15, 1982 between the Company and Computershare Trust Company of Canada, as trustee, as amended and supplemented from time to time, under which the Company's secured debentures have been issued.

Gas Sales and Transportation

Total natural gas deliveries were 39.0 PJ in 2004 compared with 36.6 PJ in 2003. Deliveries to large industrial customers increased 9.6% from 2003 to 2004 as a result of operations returning to normal following temporary shutdowns in 2003 by PNG's two largest industrial customers. These shutdowns included a four month labour dispute at West Fraser's linerboard and kraft paper mill in Kitimat and a five week maintenance shutdown at Methanex's methanol/ammonia facility in Kitimat.

Deliveries to residential and small commercial customers declined in 2004 by 6% from 2003 levels, which can be partially attributed to the weather being approximately 5% warmer, measured in heating degree days, in 2004 than in 2003.

The following table sets out, by customer category, certain information relating to PNG's gas sales and deliveries for the past three years:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
Deliveries (in TJ):			
Residential	3 279	3 464	3 503
Commercial	2 715	2 909	2 967
Small industrial	3 736	3 589	3 805
Large industrial	<u>29 241</u>	<u>26 676</u>	<u>29 188</u>
Total energy delivered	<u>38 971</u>	<u>36 638</u>	<u>39 463</u>
Customers at Year End:			
Residential	34,242	34,078	34,251
Commercial	4,993	4,978	4,941
Small industrial	52	46	58
Large industrial	<u>4</u>	<u>4</u>	<u>4</u>
Total number of customers	<u>39,291</u>	<u>39,106</u>	<u>39,254</u>
Revenue (Dollars in thousands):			
Sales revenue:			
Residential	\$37,627	\$38,815	\$30,204
Commercial	26,488	28,196	22,213
Small industrial	5,746	6,840	7,151
Large industrial			
Methanex	—	—	—
West Fraser	—	—	—
Skeena	—	—	—
Alcan	4,997	5,026	3,292
BC Hydro	35	—	—
Off system sales	<u>43,949</u>	<u>33,403</u>	<u>18,763</u>
Total sales revenue	<u>118,842</u>	<u>112,280</u>	<u>81,623</u>
Cost of sales	<u>(88,954)</u>	<u>(84,417)</u>	<u>(56,820)</u>
Operating margin from sales (1)	<u>29,888</u>	<u>27,863</u>	<u>24,803</u>
Transportation revenue:			
Residential	—	—	—
Commercial	197	182	182
Small industrial	2,839	2,705	2,328
Large industrial			
Methanex	12,191	12,344	20,589
West Fraser	2,435	3,374	3,091
Skeena	—	1,675	—
Alcan	672	577	541
BC Hydro	68	62	38
Off system sales	—	—	—
Total transportation revenue/ operating margin from transportation (1)	<u>18,402</u>	<u>20,919</u>	<u>26,769</u>
Other revenue	<u>511</u>	<u>528</u>	<u>671</u>
Total operating margin (1)	<u>\$48,801</u>	<u>\$49,310</u>	<u>\$52,243</u>

Note:

(1) Operating margin is not a recognized measure under GAAP and does not have a standardized meaning prescribed by GAAP. Therefore, operating margin may not be comparable to similar measures presented by other issuers. See "Non-GAAP Measures".

Large Industrial Customers

Overview

The Company has transportation service agreements with Methanex, West Fraser and Alcan. The Company delivers gas to its other large industrial customer, BC Hydro, under an interruptible sales and service agreement for standby power generation at BC Hydro's facility in Prince Rupert.

The agreements with Methanex, West Fraser and Alcan each provide for a specified contract demand, which is the maximum volume of gas PNG is obligated to deliver each day on a firm basis, and a specified minimum monthly charge, stated as a percentage of the monthly contract demand volume at the applicable firm toll.

Methanex

Under the terms of its agreement with Methanex, the Company provides firm gas transportation service to Methanex's methanol/ammonia complex in Kitimat. The agreement specifies a daily contract demand of 1 614.6 10³m³ (57.0 MMcf) and a minimum monthly charge equal to 100% of the monthly contract demand volume at a firm toll of \$0.50 per GJ over the term of the agreement. The contract also provides for interruptible transportation of volumes in excess of the contract demand at a toll of \$0.32 per GJ. In addition, Methanex supplies a portion of the Company's internal gas requirements equal to 4% of deliveries to Methanex. The contract also includes a profit-sharing mechanism during periods of high methanol prices and relatively low gas prices. The profit-sharing mechanism did not result in any additional revenue to the Company in 2002, 2003 or 2004. Deliveries to Methanex in 2004 accounted for approximately 67% of the volumes delivered by PNG and approximately 25% of PNG's operating margin.

The agreement with Methanex expires in October 2009, but Methanex may terminate its obligations under the agreement with six months' notice and payment of a buy-out amount to the Company on the effective date of the termination. The buy-out payment is approximately equal to the net present value of future firm contract payment obligations, net of the Company's avoidable costs if Methanex were no longer operating. The buy-out payment was set at \$30 million as at November 1, 2004 and reduces monthly to \$14 million as at November 1, 2007; thereafter, the buy-out payment reduces by \$583,333 per month.

Methanol and ammonia are subject to international commodity price fluctuations. As a result, the Company's gas deliveries to Methanex have been and may in the future be affected by the ability of the Kitimat facility to remain profitable during sustained periods of low commodity prices. On July 1, 2000 Methanex shut down the facility for 12 months in response to low methanol prices. The Company considers that there is a significant risk that Methanex will terminate its agreement with the Company in accordance with its terms prior to its expiry, in connection with divesting the methanol/ammonia complex or otherwise, or not renew the agreement when it expires in October 2009. See "Risk Factors".

West Fraser

Under the terms of its agreement with West Fraser, the Company provides firm gas transportation service to West Fraser's linerboard and kraft paper mill in Kitimat. The agreement specifies a daily contract demand volume of 170.0 10³m³ (6.8 MMcf) and a minimum monthly charge equal to 100% of the monthly contract demand volume at the applicable firm toll. A firm toll of \$0.85 per GJ applies for the first five years of the term of the agreement, ending on December 31, 2008. For the second five years of the term, the firm toll is \$0.85 per GJ adjusted by 50% of the change in the British Columbia Consumer Price Index over the five year period ending December 31, 2008. The contract also provides for interruptible transportation of volumes in excess of the contract demand at a toll of 1.15 times the firm toll. In addition, West Fraser supplies a portion of the Company's internal gas requirements equal to 4% of deliveries to West Fraser. The agreement was approved by the BCUC in July, 2004 with effect as of January 1, 2004, and resulted in a toll approximately 30% lower than that previously in effect. During 2004, deliveries to West Fraser accounted for approximately 6% of the Company's total gas deliveries and 5% of operating margin.

The agreement with West Fraser expires in December 2013, but West Fraser may terminate its obligations under the agreement with six months' notice and payment of a buy-out payment to the Company on the effective date of the termination. The buy-out payment was set at \$10,500,000 as of January 1, 2005 and reduces monthly to \$1,775,000 as of January 1, 2013. Moreover, if West Fraser has permanently shut down the Kitimat mill or has commenced the process of permanently shutting down the Kitimat mill prior to January 1, 2009, then West Fraser

may terminate the agreement with no buy-out payment effective January 1, 2009, by giving the Company at least six months' notice of termination prior to January 1, 2009. West Fraser's obligation to pay the minimum monthly charge will continue in effect until the Kitimat mill is permanently shut down. If the permanent shut down is not completed by December 31, 2009, then the agreement will continue in force until the original expiry date of December 31, 2013. See "Risk Factors".

Alcan

Under the terms of its agreement with Alcan, PNG provides firm gas transportation service to Alcan's Kitimat aluminum facility, with a toll established by the BCUC from time to time. The agreement specifies a daily contract demand volume of $30.8 \times 10^3 \text{ m}^3$ (1.1 MMcf) and a minimum monthly charge equal to 85% of the monthly contract demand volume at the firm toll. The agreement also provides for interruptible sales of gas to Alcan.

The initial term of the agreement ended November 1, 2004, but the agreement automatically continues in effect from contract year to contract year unless either party gives 12 months' notice of termination. No termination notice has been given.

During 2004, deliveries to Alcan accounted for 3% of the Company's total gas deliveries and 3% of operating margin. Alcan has produced aluminum for export from its Kitimat facility since 1952.

BC Hydro

The Company delivers gas to its other large industrial customer, BC Hydro, under an interruptible sales and service agreement for electric power generation at BC Hydro's facility in Prince Rupert. This generation plant has typically been used by BC Hydro as a stand-by facility. Deliveries of 21.6 TJ in 2004 were utilized to maintain the facility in a ready to operate mode. These deliveries represented approximately 0.1% of the Company's operating margin.

New Skeena Forest Products Inc.

Prior to 2001, Skeena Cellulose Inc. ("Skeena") was the Company's second largest customer. Skeena owned and operated a pulp mill in Prince Rupert and certain sawmill facilities in the region. In 2001, Skeena shut down the pulp mill and sought protection under the *Companies' Creditors Arrangement Act* (the "CCAA"). New Skeena Forest Products Inc. ("New Skeena") purchased the assets of Skeena pursuant to a restructuring approved under the CCAA. PNG's 2003 rate application to the BCUC assumed a prospective transportation contract with New Skeena for service to the pulp mill in Prince Rupert. It was expected that the pulp mill would operate for six months during 2003. The restructuring was not successful and the plant failed to open in 2003. As a result, PNG recorded deferred charges of \$1.7 million, before tax, in its Industrial Customer Deliveries Deferral Account. These charges are being amortized in rates and collected from customers over a three year period beginning in 2004. Subsequently, New Skeena obtained protection under the CCAA but was unsuccessful in its efforts to secure new financing to support a restructuring plan. The pulp mill has not re-opened and a bankruptcy trustee is now in the process of liquidating the assets of New Skeena.

Natural Gas Supply

All of PNG's residential customers, most of its commercial customers and a number of its smaller industrial customers continue to rely on PNG for arrangement of their gas supply, and pay rates which include PNG's gas supply commodity and delivery costs. The commodity cost of gas is passed through to customers in rates and subsequent rate adjustments, after approval by the BCUC.

PNG's large industrial customers, the majority of its small industrial customers and a few large commercial customers arrange for delivery of their gas supply requirements to PNG. These customers contract for gas transportation service on PNG's pipeline systems. Some of these customers also purchase gas from PNG to supplement their gas supply as may be required from time to time and subject to gas supply availability from PNG.

To meet the requirements of its gas sales customers, natural gas is purchased by PNG under various gas purchase contracts. Contracted gas that is surplus to the requirements of these customers may either be sold on an interruptible basis to industrial customers or be sold to other purchasers who are not PNG transmission or distribution customers ("off system sales").

Natural gas is purchased at prevailing market prices and passed through to customers without mark-up by PNG. The BCUC reviews the gas commodity portion of PNG's rates on a quarterly basis to ensure close alignment with the prevailing market prices for natural gas. Any variances in gas commodity prices paid by PNG from those included in current retail rates are deferred for subsequent refund to or recovery from customers. To moderate the variability of the gas supply commodity prices paid, PNG uses financial instruments and fixed price supply contracts under a gas price management plan that is filed with the BCUC on an annual basis.

Virtually all of the gas purchased by PNG from its gas suppliers is taken from the pooled gas stream available from the Duke Energy pipeline system. This includes all of the supply to PNG's transmission line serving its Western region service area and approximately three-quarters of the supply for the Fort St. John and Dawson Creek service areas in the Northeast region.

In addition to the supply from the Duke Energy system, the Fort St. John system incorporates two interconnections with CNRL's West Stoddart Pipeline, providing 38% of the system's requirements. In Dawson Creek, approximately 8% of the required supply is received from a local producer of sweet (pipeline quality) gas at a point where its system intersects PNG's transmission line. In Tumbler Ridge, all of the gas supply is obtained in the form of raw gas production from a local producer and is processed at facilities owned and operated by PNG.

Approximately 61% of the gas purchased by PNG in 2004 was purchased from CanWest Gas Supply Inc. ("CanWest") under a contract which expires October 31, 2005. Other supplies included purchases under seasonal and spot arrangements. PNG will contract for adequate gas supplies in the ordinary course following expiry of the CanWest agreement.

Customer Additions

In 2004, 345 new customers were connected to PNG's distribution systems, compared with 284 in 2003. This increase in customers is the result of continued strong economic activity in the Northeast region. Although 345 new customers were connected, PNG experienced a net increase of only 185 customers, as 160 customers left the distribution system, primarily in the Western region. Management believes the continued net loss of customers in the Western region reflects the generally poor economic conditions in that area.

In 2001, PNG implemented a modified main extension and service connection policy. These changes require new customers to fully cover the cost of service line connections to the distribution system. Also, in situations where main extensions are required, initial customers must fund the full amount of any shortfall between PNG's allowable investment and total estimated construction costs. This policy has eliminated PNG's role in financing a portion of main extension costs until all anticipated customers are connected to a new main.

There are few remaining candidates for conversion to natural gas in the existing building stock and limited opportunity remains to extend gas mains into unserved rural areas in the Western region. Also, with the exception of the Northeast region, local economies have been depressed as a result of uncertainty concerning future industrial activity levels. This lower level of customer additions is expected to prevail in the foreseeable future.

Government Regulation

General

PNG is subject to regulation under the *Utilities Commission Act* (British Columbia) (the "Utilities Act"). Pursuant to the Utilities Act, the BCUC regulates the business of public utilities, including the construction and operation of major facilities, the issuance of securities, determination of rates for the sale and transportation of gas and the terms and conditions of service. In approving rates, the BCUC must determine that such rates reflect a fair and reasonable charge for service of the nature and quality furnished by PNG to its customers, and that such rates are sufficient to yield PNG a fair and reasonable compensation for its services, including a fair and reasonable return upon the value of its property.

PNG is also subject to regulation under the *Pipeline Act* (British Columbia) in respect of the construction, operation and maintenance of its transmission pipeline facilities.

Rate Regulation

PNG's rates are determined by the BCUC on a fixed rate method, under which rates are set on the basis of annual forecasts of both the cost of service and throughput for PNG's transmission and distribution system. The cost

of service consists of the cost of purchased gas and the cost of transporting all gas delivered through PNG's system, including operating, maintenance and administrative expenses, depreciation of facilities, income and other taxes and a return on rate base. Rate base is composed of the depreciated book value of plant in service, plus unamortized deferred charges, plus allowance for working capital, less deferred income taxes. The rate base is approved annually by the BCUC for rate making purposes, including approval of annual capital additions forecast by PNG. Forecast capital additions are usually approved as applied for by PNG with minor modifications. If the actual cost of forecast capital additions exceeds the amount approved by the BCUC, the excess cost may be subject to a prudency review by the BCUC depending on the extent actual costs exceed the amount approved by the BCUC. The BCUC determines the allowable return on rate base after considering a variety of factors, including the degree of risk associated with PNG's business and the cost of capital.

A key component of the cost of capital is the after-tax return on the common equity component of the capital structure (the "ROE"). The BCUC uses a formula to determine, on an annual basis, the ROE applicable to a low risk benchmark utility based on forecast long term Government of Canada bond rates, plus 350 basis points. PNG's risk profile is compared by the BCUC to the low risk benchmark utility to determine PNG's utility-specific risk premium relative to the ROE applicable to the low risk benchmark utility. PNG's utility-specific risk premium is then added to the low risk benchmark utility risk premium to determine the ROE which PNG is allowed to include in rates each year. PNG's ROE is therefore subject to variations in forecast long term Canada bond rates. The ROE changes on a one to one basis for changes in long term Canada bond rates below six percent. For changes to long term Canada bond rates above six percent, the ROE changes by 80% of the change. The ROE is set by the BCUC in November each year to be applied in the following calendar year.

The BCUC has approved a number of deferral accounts for PNG to record costs and revenues for various items for recovery from customers, or refund to customers, over a future time period. The general purpose of a deferral account is to keep PNG or its customers whole in respect of the subject matter of the deferral account. Two main deferral accounts apply to all divisions of PNG:

- Gas Cost Variance Account ("GCVA") — The commodity cost of gas included in customer rates is based on a forecast of the gas market prices PNG expects to pay to gas suppliers over a 12 month period. The difference between the forecast gas cost PNG charges its customers and the actual gas cost incurred by PNG is recorded by PNG in the GCVA. The balance in this account is reviewed by PNG and the BCUC every quarter. If actual gas costs exceed forecast gas costs, the difference will be recovered from customers by an increase in future rates. If actual gas costs are lower than forecast gas costs, the difference will be refunded to customers through a reduction in future rates. In this way, customers, over time, pay the same cost for gas as is paid by PNG.
- Rate Stabilization Adjustment Mechanism ("RSAM") — PNG forecasts the revenue it will receive from customers based on an annual forecast of gas deliveries to customers. As it is not possible to forecast deliveries to customers with complete accuracy for a variety of reasons, including the effect of weather on gas consumption, PNG is allowed by the BCUC to record the difference between forecast and actual revenues from deliveries to residential and small commercial customers in the RSAM deferral account (excluding revenue differences arising from changes in the number of customers from that forecast). If actual deliveries exceed forecast deliveries, the resulting revenue difference will be recorded in the RSAM deferral account and refunded to customers in future rates. If actual deliveries are less than forecast deliveries, the resulting revenue difference will be recorded in the RSAM deferral account and recovered from customers in future rates.

Revenue requirements applications for PNG's three service areas (the Western region service area and two service areas in the Northeast region) are submitted to the BCUC, generally on an annual basis. The Northeast region contains two divisions for rate making purposes. One division comprises the Fort St. John/Dawson Creek service area, and the other division the Tumbler Ridge service area. The BCUC may consider these applications through a public hearing process (either oral or written), or through negotiations with the customers under alternate dispute resolution processes. The 2004 and 2005 revenue requirements applications and related BCUC decisions for each service area are summarized in the following sections.

Western Region

In November 2003, PNG filed a revenue requirements application with the BCUC for approval of new rates to take effect January 1, 2004. The application for 2004 was considered by the BCUC through a public hearing process. The BCUC issued its decision in July, 2004. The 2004 allowed rate of return on common equity for the Western region was 9.80%, based on a deemed common equity component of 36%. The allowed rate of return on common equity included a 65 basis point premium over the low risk benchmark utility rate of return.

The RSAM deferral account was approved by the BCUC in 2003. In general, the RSAM deferral balance at the end of each year is recovered from or refunded to customers over the following three year period. During 2004, an after tax amount of approximately \$0.9 million was credited to income in respect of this deferral for the Western region.

For 2004, the BCUC continued its direction to defer the difference between actual operating margin from deliveries to Methanex, West Fraser, Alcan and BC Hydro and the forecast operating margin used by PNG in its revenue requirement application in an Industrial Customers Deliveries Deferral Account (“ICDDA”). The ICDDA reduced 2004 net earnings by \$0.2 million as a result of actual 2004 deliveries to these customers exceeding forecast amounts. The BCUC also accepted PNG’s forecast of gas supply costs for 2004. Rate riders were approved in various amounts for 2004 to refund a credit balance accumulated in the GCVA. In 2004, the reduction in customer revenue from credit rate riders totalled \$1.6 million, and was applied, on an after tax basis, to reduce the GCVA balance.

In 2004, the net book value of a propane air plant which is no longer in service was removed from property, plant and equipment and an after tax amount of approximately \$0.8 million was transferred to a deferral account for proposed future recovery from customers over a period of twenty years commencing in 2005. The ultimate realization of the amount transferred to the deferral account is subject to a future decision of the BCUC.

The 2005 revenue requirements application for the Western region was filed with the BCUC in December 2004. The application sought approval of increased delivery charges and increased gas supply commodity charges, effective January 1, 2005. Approximately two-thirds of the increase in the gas delivery charge was due to PNG seeking approval of an increase in common equity from the deemed 36% approved by the BCUC in 2004 to PNG’s actual common equity of approximately 51%. The BCUC approved interim gas delivery charge increases effective January 1, 2005 applying the existing deemed 36% common equity ratio. The final gas delivery rates for 2005 will be determined under a review process to be determined after the BCUC releases its decision on PNG’s application to convert to an income trust ownership structure. See “— Application to BCUC to Convert the Company to an Income Trust Structure” below.

The BCUC accepted the gas supply commodity charge increases applied for by PNG, effective January 1, 2005. The final gas supply commodity charges for the first quarter of 2005 are approximately 10% higher than those embedded in rates as of December 31, 2004.

The forecast 2005 residential and commercial deliveries contained in the 2005 revenue requirements application are approximately 6% higher than actual gas deliveries to those customer classes in 2004. Deliveries to small industrial customers are projected to be approximately 9% lower in 2005 compared to actual gas deliveries in 2004.

In November 2004 the BCUC confirmed that its formula for determining the allowable return on common equity in 2005 resulted in a 9.03% return for a low risk benchmark utility for the year. For the Western region, a return on equity risk premium of 65 basis points applies, resulting in an allowable return on common equity of 9.68% for 2005.

Northeast Region

Fort St. John/Dawson Creek Division

In July 2004, the BCUC issued its decision on the Fort St. John/Dawson Creek division 2004 revenue requirements application, following a written hearing. The 2004 allowed rate of return on common equity was 9.55% for the Fort St. John/Dawson Creek division, based on a deemed common equity component of rate base of 36%. The allowed rate of return on common equity included a 40 basis point premium over the low risk benchmark utility rate of return.

The BCUC accepted PNG's forecast of gas supply costs for 2004. Rate riders were approved for 2004 to refund credit balances recorded in the GCVA at December 31, 2003 over a period of three years. In 2004, customer revenue from rate riders totalled \$0.2 million, which was applied, on an after-tax basis, to reduce the GCVA balance.

During 2004, \$256,000, net of income taxes, was credited to income in respect of the RSAM deferral for the Fort St. John/Dawson Creek division.

The Fort St. John/Dawson Creek revenue requirements application for 2005 was filed in December 2004. The application sought BCUC approval to increase both the gas delivery charge component of rates as well as the gas commodity charges. The BCUC approved interim delivery charges effective January 1, 2005 at the level applied for, which includes a deemed common equity of 36% and an allowable return on common equity of 9.43% for 2005. The gas supply commodity charge increases received final approval. In total, the rate increases effective January 1, 2005 result in interim rate increases for residential and small commercial customers of approximately 5% and 4% respectively, compared to rates in effect as of December 31, 2004.

The BCUC is conducting a written hearing process for the 2005 revenue requirements application. A decision by the BCUC is expected in the second quarter of 2005.

Tumbler Ridge Division

In July 2004, the BCUC issued its decision on the Tumbler Ridge division 2004 revenue requirements application, following a written hearing. The 2004 allowed rate of return on common equity was 9.80%, based on a deemed common equity component of 36%. The allowed rate of return on common equity included a 65 basis point premium over the low risk benchmark utility rate of return.

During 2004, \$77,000, net of income taxes, was credited to income in respect of the RSAM deferral for the Tumbler Ridge division.

The Tumbler Ridge revenue requirements application for 2005 was filed with the BCUC in December 2004. The application sought BCUC approval to increase the gas delivery charge component of rates effective January 1, 2005 and no changes in the gas commodity charge component of rates. The requested increases in the gas delivery charge component are primarily due to increased operating costs, including increases in the cost of gas required for operating PNG's processing plant. The BCUC approved interim delivery charges effective January 1, 2005 at the level requested, which includes a deemed common equity of 36% and an allowable return on common equity of 9.68% for 2005. The resulting interim rate increases were approximately 3% for residential and small commercial customers relative to rates in effect on December 31, 2004.

The BCUC is conducting a written hearing process for the 2005 revenue requirements application. A decision by BCUC is expected in the second quarter of 2005.

Rate Base and Common Equity

The following table summarizes, for each of PNG's three service areas, the rate base, common equity component of rate base and the after-tax rate of return on common equity approved by the BCUC for the three years ended December 31, 2004:

	Year Ended December 31,		
	2004	2003	2002
	(Dollar amounts in thousands)		
Western region:			
Rate base	\$135,488	\$136,037	\$136,983
Common equity component	36.0%	36.0%	36.0%
Allowed return on common equity	9.80%	10.17%	9.88%
Fort St. John/ Dawson Creek division:			
Rate base	\$ 30,521	\$ 28,219	\$ 26,281
Common equity component	36.0%	36.0%	36.0%
Allowed return on common equity	9.55%	9.82%	9.63%
Tumbler Ridge division:			
Rate base	\$ 1,043	\$ 1,166	\$ 1,180
Common equity component	36.0%	36.0%	36.0%
Allowed return on common equity	9.80%	10.07%	9.88%

Application to BCUC to Convert the Company to an Income Trust Structure

Background

On January 30, 2004 PNG filed an application with the BCUC seeking approval to convert to an income trust ownership structure. The decision to seek approval to convert to an income trust structure was primarily based on the following circumstances and their impact on PNG's liquidity and access to capital:

- On July 1, 2000, Methanex shut down its methanol plant at Kitimat for 12 months during a period of low methanol prices. Methanex was then, and is currently, PNG's largest customer, and at the time of the shutdown accounted for approximately 70% of PNG's total gas throughput and 40% of its total operating margin.
- Although the Methanex plant resumed operation in 2001 and PNG entered into a new contract with Methanex in 2002, the continuing significance of Methanex as a customer (accounting for approximately 25% of PNG's operating margin in 2004), coupled with the fact that the new contract expires in 2009 and can be terminated by Methanex before that date, has precluded access by PNG to traditional institutional lenders as a source of long term debt. Since 2002 PNG has had access only to short term debt which cannot be used to refinance existing long term debt.
- PNG is accordingly relying on operating cash flow to fund capital expenditures and amortization of long term debt, as well as to pay dividends. See "Management's Discussion and Analysis".
- PNG has significant near and medium term needs to access capital markets. In particular, PNG needs to access long term debt markets to refinance its maturing long term debt. Over the next ten years PNG must refinance approximately \$46 million of long term debt, including \$4.4 million of debt in 2005 and \$4.9 million per year over the four year period from 2006 to 2009, inclusive.

Given these circumstances, PNG concluded in early 2003 that reorganizing its business under an income trust ownership structure would be the best means of addressing PNG's capital requirements on a long term basis. The Company believes one of the primary advantages of the income trust structure is that it would allow PNG to reduce its long term secured debt significantly, and replace that debt with long term subordinate debt advanced to PNG by the income trust using proceeds from an initial public offering of trust units. This would improve PNG's financial flexibility and access to capital without PNG having to increase rates to its customers.

Initial Decision, Subsequent Application and Approval Requirements

On July 29, 2004 the BCUC issued a decision denying PNG's initial application to convert to an income trust structure, citing concerns over the requirement to deem a common equity component higher than the proposed income trust's level of equity, as well as requirements to deem income tax expenses for rate making purposes.

PNG reviewed the BCUC decision and concluded the BCUC's concerns could be addressed in a new application. In December 2004, PNG filed a new application with the BCUC for approval to convert to an income

trust structure. The Company believes the new application addresses the concerns raised by the BCUC in its denial of the first application. In particular, the new application requests that the BCUC set customer rates using the actual capital structure of the proposed income trust rather than a deemed capital structure.

An oral public hearing on PNG's application is scheduled to commence on May 10, 2005.

In addition to approval by the BCUC, the conversion to an income trust structure will require:

- approval by 75% of the votes cast at a meeting of the shareholders of the Company to approve a plan of arrangement under the *Business Corporations Act* (British Columbia);
- court approval of the plan of arrangement; and
- agreement with PNG's debentureholders to allow PNG to redeem approximately \$40 million of its outstanding debentures on acceptable terms and conditions.

The plan of arrangement is also expected to be conditional upon the completion by the proposed income trust of an initial public offering of units, the proceeds of which would be used to redeem a portion of the outstanding debentures and all of the Preferred Shares, and to pay conversion and transaction expenses. PNG can give no assurances that the required approvals will be obtained, that there will be acceptable market conditions for the proposed income trust's initial public offering or that the conversion by PNG to an income trust structure will be completed. See "Risk Factors".

Engineering and Operations

In-Line Inspection

PNG has processes in place to monitor the ongoing integrity of its transmission pressure pipeline to ensure protection of the public and the environment by demonstrating that all transmission pipelines are suitable for continued safe and reliable service. A key aspect of these processes focuses on the internal inspection of the pipeline using in-line inspection tools and subsequent repair activities that arise from the information gathered.

PNG began implementing in-line inspection programs on its transmission pipeline in 1989. The 2004 in-line inspection activity involved running the inspection tool through three different sections of twelve-inch line totalling approximately 45 kilometres in length. The results of these inspections were favourable. PNG intends to continue its in-line inspection program on an annual basis in 2005 and into the foreseeable future.

Compressor Control Systems

Installation of a programmable logic controller-based system at the Burns Lake compressor station was completed in 2004. The new system offers more reliable control and a greater level of operational flexibility, while allowing for remote control and troubleshooting of the compressor unit. As of December 31, 2004, all of PNG's compressor had been upgraded with these control systems.

Khyex River Slide

On November 28, 2003, a massive debris slide 55 kilometres east of Prince Rupert ruptured a section of the eight-inch high-pressure transmission pipeline. A temporary line was installed in order to restore service to the affected customers. The temporary line remains in service while PNG waits for the soil in the area of the slide to stabilize. In accordance with BCUC approvals, the costs of the temporary repair were deferred and are to be collected from customers in rates over ten years commencing in 2004. When a permanent repair is complete the costs will become part of PNG's rate base. It is not yet known when a permanent repair will be made.

Work Channel Slide

On November 5, 2004, a debris slide 25 kilometres east of Prince Rupert ruptured a section of the eight-inch high-pressure transmission pipeline. Service to 200 customers in Prince Rupert and Port Edward was interrupted for 42 hours. The cost of temporary and permanent repairs was less than \$0.4 million.

Capital Expenditures

Total capital expenditures in 2004 were \$11.3 million, \$5.9 million higher than those incurred in 2003 and \$4.6 million above the average level of expenditures for the last five years. Of the capital expenditures in 2004, \$4.4 million was for a special project to directionally drill under the Salmon River to replace a dual underwater

transmission system crossing. The capital expenditures for this project were initially estimated to be \$1.8 million. The balance of the capital expenditures were for maintenance capital as well as customer additions to the distribution system in the Northeast region.

Planned capital expenditures in 2005 are forecast to be approximately \$7.3 million. These are primarily maintenance capital expenditures for transmission mainline rehabilitation and capital expenditures for new distribution mains and services. Contractual commitments have yet to be made for major planned capital expenditures for 2005. These capital expenditures are expected to be funded from cash flow from operations.

Operating Activities

Operating, maintenance and administrative costs totalled \$18.7 million in 2004, compared to \$18.5 million in 2003. The higher expenses mainly reflect higher administrative costs associated with provision of employee benefits including health and welfare plan premiums and pension expense. These increases were partially offset by reduced maintenance costs, as a compressor overhaul was not required in 2004. Operating expenses in 2004 also included approximately \$1.0 million relating to unaccounted for gas losses, compared to nil in 2003. A consultant has been retained by PNG to identify possible causes contributing to the gas losses, which have occurred primarily in the Northeast region.

Social and Environmental Policies and Environmental Protection

In the ordinary course of its operations, PNG is required to comply with applicable federal and provincial environmental laws. PNG makes expenditures on environmental protection in the operation of its gas pipeline and distribution systems and in the construction of new facilities. These expenditures are recovered from customers in the rates approved by the BCUC. PNG does not anticipate making any material capital expenditures for environmental compliance during 2005. PNG did not incur any specific expenditures on research and development during 2004 and does not expect to do so in 2005.

Employees

At December 31, 2004, PNG had 97 employees, comprised of 77 unionized and 20 non-unionized employees. All unionized employees are members of the International Brotherhood of Electrical Workers (the "Union"). PNG's most recent collective agreement with the Union expired on October 31, 2004. PNG and the Union have signed a memorandum of agreement regarding a new three year collective agreement. The memorandum of agreement was subject to a ratification vote by the unionized employees. On April 1, 2005, PNG was advised by the Union that the memorandum of agreement had been ratified. There has been no job action initiated by PNG's unionized workers in over 20 years.

Trends and Competition

As a regulated utility, PNG does not face competition from other natural gas transmission and distribution companies. PNG does, however, compete with other energy sources in meeting the needs of energy consumers in its service areas. The main sources of competition are from electricity and wood in the residential sector, electricity in the commercial sector and wood waste in the industrial forestry sector (see "Risk Factors — Usage Risks").

PNG has experienced reductions in average gas consumption per residential and commercial customer. In 2004, the average use per customer was approximately 80% and 86%, for residential and commercial customers respectively, of the use per customer in the late 1990s. PNG believes that only a small portion of the reduction in average gas consumption has resulted from substitution of other fuels for natural gas, with a limited amount of load having switched to electricity at this time. The main reason for the reduction in average gas consumption is conservation measures undertaken by consumers in response to higher natural gas prices and poor economic conditions experienced over this period in the Western region. Gas consumption by small industrial customers in the Western region has also declined through conservation and substitution of wood waste for natural gas.

In addition to the effect of conservation and substitution of energy sources, PNG experienced a net loss in the number of residential customers from 2001 through 2003, with 2004 remaining flat relative to 2003. Over the same period, the number of commercial customers has been more resilient, with a small net loss in 2001 and an average annual growth rate of 0.7% since then. The poor economic conditions in the Western region are believed to be responsible for the majority of the decline in the number of residential customers. Certain small industrial customers

have also closed down, contributing to the reduced economic activity in the Western region and the decline in gas consumption in the small industrial sector.

These recent trends are not necessarily indicative of future trends. Management of PNG expects there to be a limit to the conservation measures that can be undertaken by residential, commercial and industrial customers. Further, there are a number of initiatives and prospects in PNG's Western region that could have a positive impact on the economic conditions in this service area, including:

- development of a container handling facility at the Port of Prince Rupert;
- construction of a proposed oil pipeline from Alberta to tidewater at either Kitimat or Prince Rupert; and
- separate proposals for liquefied natural gas ("LNG") import and regasification facilities at Prince Rupert and Kitimat.

The proponent of the proposed LNG facility in Kitimat, Kitimat LNG Terminal ("Kitimat LNG"), has commenced the process to obtain a Project Approval Certificate from the British Columbia Environmental Assessment Office and Canadian Environmental Assessment Agency. This certificate would allow construction and operation of its project, which is proposed initially to import and regasify up to 610 MMcf/day of natural gas commencing in late 2008. Kitimat LNG has indicated its desire to utilize PNG's natural gas transportation services to deliver the regasified LNG into the Duke Energy system at the point of the existing interconnection with PNG. PNG would be required to reverse the flow of its pipeline and expand capacity in the event the Kitimat LNG project proceeds as planned.

In PNG's Northeast region there has been recent growth in the oil and gas sector, as well as the coal sector, which may expand PNG's customer base in that region.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING INFORMATION

The following selected financial information has been derived from the consolidated financial statements of the Company appearing elsewhere in this prospectus, and should be read in conjunction with these financial statements, the related notes, and “Management’s Discussion and Analysis”.

	Year Ended December 31,		
	2004	2003	2002
	(Dollar amounts in thousands, except per share data)		
Statement of Income Information:			
Operating revenues	\$137,755	\$133,727	\$109,063
Operating margin (1)	48,801	49,310	52,243
Net income	5,408	5,668	4,590
Basic earnings per Common Share	\$ 1.41	\$ 1.49	\$ 1.20
Diluted earnings per Common Share	1.38	1.46	1.18
Dividends paid per Common Share	0.80	3.55	—
Dividends paid per Preferred Share	1.69	1.69	1.69
Balance Sheet Information:			
Total assets	\$207,657	\$206,414	
Total long term financial liabilities	97,284	101,481	
Preferred shares	5,000	5,000	
Common shareholders’ equity (2)	73,950	71,522	
Common shareholders’ equity (2) per share	20.52	19.96	
Other Financial Information:			
EBITDA (1)	26,182	26,193	28,870
Ratio of EBITDA (1) to interest expense	3.27	3.32	3.75
Selected Operating Information:			
Deliveries (TJ):			
Sales	7 338	7 754	8 045
Transportation service	31 633	28 884	31 418
Total	38 971	36 638	39 463
Customers at period end	39,291	39,106	39,254
Weighted average cost of gas purchased (per GJ)	\$ 6.42	\$ 6.59	\$ 4.11

Notes:

- (1) EBITDA and operating margin are not recognized measures under GAAP and do not have standardized meanings prescribed by GAAP. Therefore, EBITDA and operating margin may not be comparable to similar measures presented by other issuers. See “Non-GAAP Measures”.
- (2) Common shareholders’ equity is comprised of common share capital, contributed surplus and retained earnings.

PNG’s natural gas distribution business is seasonal, with higher sales in the colder winter months and lower sales in warmer months because a substantial portion of its gas sales is used for space heating purposes. As a result, PNG earns the majority of its net income in the first and fourth quarters of its fiscal year and often incurs losses in the other two quarters.

<u>2004</u>	Quarter Ended			
	Mar. 31	June 30	Sept. 30	Dec. 31
	(Dollar amounts in thousands, except for per share data)			
Operating revenues	\$43,584	\$28,245	\$25,169	\$40,757
Net income (loss)	3,848	317	(1,427)	2,670
Earnings (loss) per Common Share — basic	\$ 1.05	\$ 0.06	\$ (0.42)	\$ 0.72
Earnings (loss) per Common Share — diluted	1.03	0.06	(0.42)	0.71

<u>2003</u>	<u>Quarter Ended</u>			
	<u>Mar. 31</u>	<u>June 30</u>	<u>Sept. 30</u>	<u>Dec. 31</u>
	(Dollar amounts in thousands, except for per share data)			
Operating revenues	\$41,683	\$28,571	\$24,025	\$39,448
Net income (loss)	3,679	47	(723)	2,665
Earnings (loss) per Common Share — basic	\$ 1.01	\$ (0.01)	\$ (0.22)	\$ 0.72
Earnings (loss) per Common Share — diluted	0.99	(0.01)	(0.22)	0.70

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following management's discussion and analysis should be read together with the consolidated financial statements of the Company and related notes included elsewhere in this prospectus. This discussion contains forward looking statements. Please see "Forward Looking Statements" for a discussion of the risks, uncertainties and assumptions relating to these statements.

Results of Operations

Year Ended December 31, 2004 Compared to the Year Ended December 31, 2003

Net income for 2004 was \$5.4 million, compared with \$5.7 million for 2003, or a decrease of 4.6%. After providing for dividends on Preferred Shares, earnings per Common Share for 2004 were \$1.41 compared with \$1.49 for 2003. The decrease in net income was primarily a result of higher expense for gas used in operations but not accounted for. The impact of this unaccounted for gas loss, net of tax, was approximately \$0.7 million in 2004, compared to nil in 2003. A consultant has been retained by PNG to identify possible causes contributing to the gas loss, which has occurred primarily in the Northeast region.

Deliveries to residential and commercial customers in 2004 were lower by 0.4 PJ, or 6%, compared to deliveries in 2003. Some of the reduction in deliveries was due to weather, which was approximately 5% warmer in 2004 than in 2003. Deliveries to residential and small commercial customers in 2004 were lower by 0.5 PJ, or 8%, compared to the forecast volumes used to set customer rates. In 2003, deliveries were 6% lower than the forecast volumes used to set rates. The reduction in deliveries did not significantly impact net income due to the existence of a deferral account that captured the after-tax value of the revenue variance, amounting to \$1.2 million (\$0.9 million in 2003), arising from differences between actual and forecast volumes for residential and small commercial customers.

Operating revenues in 2004 increased to \$137.8 million as compared with \$133.7 million in 2003, largely due to the increase of \$10.5 million in off system sales. The Company does not realize any profit or loss on off system sales, as all revenues from off system sales reduce the Company's cost of gas for regulatory purposes. Natural gas commodity prices, which are passed through the Company's sales customers without mark-up, are very volatile and result in significant variability of the Company's reported operating revenues. Operating revenues in 2004 and 2003 were significantly higher than in 2002, largely due to the higher commodity cost of gas.

Operating margin in 2004 decreased to \$48.8 million, as compared with \$49.3 million in 2003. This decrease was due to reductions in customer rates in 2004 that were based on anticipated reductions in amortization and company use gas expenses.

Year Ended December 31, 2003 Compared to the Year Ended December 31, 2002

Net income for 2003 was \$5.7 million, compared with \$4.6 million for 2002, or an increase of 24%. After providing for dividends on Preferred Shares, earnings per Common Share for 2003 were \$1.49 compared with \$1.20 for 2002. Deliveries to residential and commercial customers in 2003 were lower by 0.1 PJ, or 1.4%, compared to deliveries in 2002. Some of the reduction in deliveries was due to weather, which was approximately 1% warmer in 2003 than in 2002. Deliveries to residential and commercial customers in 2002, which was prior to the BCUC approval of the RSAM deferral account, were lower by 0.8 PJ, or 10%, compared to the forecast volumes used by the BCUC to set customer rates, negatively impacting 2002 net income by \$1.9 million. In 2003, deliveries were 1.2% lower than the forecast volumes used to set rates. The reduction in 2003 deliveries did not significantly impact net income due to the existence of the RSAM deferral account that captured the after-tax value of the revenue variance, amounting to \$0.9 million, arising from differences between actual and forecast volumes for residential and

commercial customers. Net income in 2003 was also negatively impacted by \$0.6 million relating to increased administrative costs incurred in reviewing and pursuing strategic options.

Operating revenues in 2003 increased to \$133.7 million as compared with \$109.1 million in 2002, largely due to the increase in the commodity cost of natural gas that is passed through to customers without markup as well as an increase of \$14.6 million in off system sales.

Operating margin in 2003 decreased to \$49.3 million, as compared with \$52.2 million in 2002. This decrease was due to reductions in customer rates in 2003 that were based on anticipated reductions in amortization and company use gas expenses.

Liquidity

Contractual Obligations

	Payments Due by Period as of December 31, 2004				
	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
	(Dollar amounts in thousands)				
Long term debt	\$ 85,829	\$ 4,382	\$ 9,764	\$ 9,762	\$61,921
Purchase obligations	42,714	41,678	1,036	—	—
Total	<u>\$128,543</u>	<u>\$46,060</u>	<u>\$10,800</u>	<u>\$9,762</u>	<u>\$61,921</u>

The purchase obligations in the table above represent commitments by the Company to purchase natural gas from its suppliers. The Company enters into a number of arrangements to purchase gas on a seasonal basis for resale to its customers during the heating season.

Funding Requirements

The Company's capital expenditures, working capital needs, dividend payments and debt repayments are funded from a combination of sources. During 2004, the primary sources of funding were \$16.4 million of cash generated from operations, \$0.3 million of cash held at December 31, 2003, and a draw of \$3.1 million in demand loans under an operating line of credit.

The Company purchases gas for resale to its gas sales customers and passes through the commodity cost of gas to those customers without mark-up. The rates charged to gas sales customers are based, in part, on projected gas supply prices. The Company's liquidity requirements are affected by delays between increases or decreases in the cost of gas purchased by the Company and regulatory approval of rate adjustments to reflect the cost increases or decreases.

Financial Ratios

The following table shows the ratio of EBITDA to interest expense for PNG for the three years ended December 31, 2004:

	2004	2003	2002
	(Dollar amounts in thousands)		
Net income for the year	\$ 5,408	\$ 5,668	\$ 4,590
Add:			
Income taxes	4,120	4,760	6,935
Interest expense	8,014	8,109	7,692
Depreciation	7,877	7,873	7,953
Amortization of deferred charges	763	503	1,700
EBITDA (1)	<u>\$26,182</u>	<u>\$26,913</u>	<u>\$28,870</u>
Ratio of EBITDA (1) to interest expense	3.27x	3.32x	3.75x

Note:

(1) EBITDA is not a recognized measure under GAAP and does not have a standardized meaning prescribed by GAAP. See "Non-GAAP Measures".

Funding Costs

Interest Expense

<u>Interest Expense</u>	<u>2004</u>	<u>2003</u>
	(Dollar amounts in thousands)	
Long term interest expense	\$7,564	\$7,536
Short term interest expense	<u>450</u>	<u>573</u>
Total	<u>\$8,014</u>	<u>\$8,109</u>
Effective blended cost of debt	9.0%	8.7%

The slight increase in the effective blended cost of debt is due to a more rapid amortization of the lower rate variable interest debentures, compared to the fixed rate debentures.

Capital Expenditures

Total capital expenditures in 2004 were \$5.9 million higher than those incurred in 2003 and \$4.6 million above the average level of expenditures for the last five years. Of the capital expenditures in 2004, \$4.4 million was for a special project to directionally drill under the Salmon River to replace a dual underwater transmission system crossing. The balance of the capital expenditures were for maintenance capital as well as customer additions to the distribution system in the Northeast region.

<u>Capital Expenditures</u>	<u>2004</u>	<u>2003</u>
	(Dollar amounts in thousands)	
Transmission system	\$ 7,032	\$2,310
Distribution system	2,905	2,356
Processing plant	80	41
Other	<u>1,259</u>	<u>699</u>
Total	<u>\$11,276</u>	<u>\$5,406</u>

Planned capital expenditures in 2005 are forecast to be approximately \$7.3 million. These are primarily maintenance capital expenditures for transmission mainline rehabilitation and capital expenditures for new distribution mains and services. Contractual commitments have yet to be made for major planned capital expenditures for 2005. These capital expenditures are expected to be funded from cash flow from operations.

Capital Resources

<u>Composition of Capital Structure</u>	<u>At December 31, 2004</u>	<u>At December 31, 2003</u>
Preferred shareholders' equity	2.9%	2.9%
Common shareholders' equity	43.3	42.2
Short term debt	3.5	1.7
Long term debt, including current portion	<u>50.3</u>	<u>53.2</u>
	<u>100.0%</u>	<u>100.0%</u>

For rate determination purposes the Company is permitted to earn a return on its invested capital to the extent of its approved rate base. Rate base is composed of the depreciated book value of plant in service, plus unamortized deferred charges, plus an allowance for working capital, less deferred income taxes. The BCUC sets customer rates at a level that is intended to allow the Company to earn its approved after tax rate of return on common equity on 36% of rate base. The 36% is significantly below the 43% common equity on the Company's balance sheet, and below the requested increase to 51% for common equity in the 2005 rate application for the Western region.

Equity

The common shareholders' equity at December 31, 2004 was \$20.52 per share, compared to \$19.96 per share at December 31, 2003.

Dividends

Dividends on Preferred Shares totalling \$1.6875 per share were paid in 2004, the same as in 2003.

Dividends on Common Shares totalling \$0.80 per share were paid in 2004, compared to \$3.55 per share paid in 2003. The 2003 dividends paid included a special dividend of \$2.75 per Common Share paid in January 2003. The special dividend was declared following the issuance of \$15 million of new long term financing in December 2002, and resulted in a capital structure that was more consistent with that approved by the BCUC.

A total of \$3.2 million in dividends was paid in 2004, compared to \$13.1 million paid in 2003.

Short Term Debt

Throughout 2004 the Company had a bank demand operating and hedge line of credit of \$25 million, with interest based on the prime rate or bankers' acceptance rates. This line of credit provided funds for general corporate and working capital requirements. The amount available under this facility was subject to borrowing base requirements. The line of credit was collateralized by the pledge of a \$25 million debenture and a charge on certain accounts receivable and inventories.

As a result of seasonality in operations, marginable receivables and other assets are significantly reduced in the second and third quarters compared to the winter heating season, thus constraining availability of the demand line of credit. At December 31, 2004, the amount available under the facility was approximately \$6.4 million, of which \$6.1 million had been drawn. The Company provided covenants to its operating lender, all of which were complied with during 2004.

In January 2005, the Company arranged new credit facilities which include a \$20 million operating line and a \$15 million risk management facility. The operating line is subject to borrowing base requirements and financial covenants which may act to restrict the amount the Company can borrow under the operating line. The borrowing base under the new facility is less restrictive than the previous operating line, and the amount available for borrowing by the Company has therefore increased. As of March 1, 2005, the borrowing base exceeded the \$20 million available under the operating line.

In addition to the borrowing base, the Company has provided certain financial covenants to its operating lender. One of these covenants is a restricted payments test which, in essence, prevents the Company from borrowing under the operating line to fund capital expenditures, make scheduled debt amortization payments or make dividend payments. If the Company does not have access to new capital to fund capital expenditures or scheduled debt amortization payments, the operation of this covenant will require that the Company's operating cash flow be sufficient to cover capital expenditures, scheduled debt amortization payments and dividends. See "Risk Factors — Liquidity, Cash Flow and Capital Availability Risks".

The risk management facility allows the Company to hedge natural gas purchases in accordance with its annual gas contracting and gas supply price management plan and to enter into interest rate hedging transactions to the extent of a total maximum exposure of \$15 million, with exposure calculated by the facility provider using its standard methodology.

Off Balance Sheet Arrangements

As of December 31, 2004, the Company had no off balance sheet arrangements, other than the natural gas hedging contracts described in "— Changes in Accounting Policies Including Initial Adoption — Financial and Other Instruments" below.

Transactions with Related Parties

The Company had no transactions with related parties during 2004.

Critical Accounting Estimates

Operating revenues include natural gas sales that are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading date to the end of the reporting period for such operating revenues. These estimates are made assuming normal consumption patterns, which may differ from actual consumption patterns. The estimates of unbilled operating revenue comprise 5.7% of the Company's operating

revenues for 2004. Through future meter readings, the usage estimates are replaced with actual delivered volumes, which become reflected in the Company's financial results at that time.

The Company is involved in a dispute with a customer over the payment for gas transported to the customer. The dispute relates to the customer's obligation to supply its own gas for transportation to its facilities, or failing that, to pay for gas delivered to those facilities. The Company believes it has a substantial case for recovery of the amounts billed and has recorded the related accounts receivable at management's best estimate of the amount ultimately recoverable. Approximately \$1.6 million relating to the dispute has been included in accounts receivable at December 31, 2004. There is a risk that the amount ultimately recovered may be materially different from management's estimate. See "Legal Proceedings".

Changes in Accounting Policies Including Initial Adoption

Valuation of Property, Plant and Equipment

In 2003, the Canadian Institute of Chartered Accountants ("CICA") approved a new accounting standard for the recognition, measurement and disclosure of the impairment of long-lived assets (Section 3063). The new standard applies to non-monetary long-lived assets, including property, plant and equipment and intangible assets with finite useful lives. Under the new requirements, an impairment loss is recognized when the carrying amount of an asset to be held and used exceeds the sum of the undiscounted cash flows expected from its use and eventual disposition. An impairment loss is measured as the amount by which the asset's carrying amount exceeds its fair value. The Company adopted the new accounting standard prospectively, beginning January 1, 2004. Adoption of the new standard had no material effect on the Company's financial position or earnings in 2004.

In 2003, the CICA approved a new accounting standard for the recognition, measurement and disclosure of liabilities for asset retirement obligations and the associated asset retirement costs (Section 3110). A company will be required to recognize the fair value of a liability for an asset retirement obligation in the period in which the obligation is incurred when a reasonable estimate of fair value can be made. The Company adopted the new accounting standard prospectively beginning January 1, 2004, and adoption of the new standard had no material effect on the Company's financial position or earnings in 2004.

Hedging Relationships

In 2003, the CICA approved new guidelines relating to the identification, designation, documentation and effectiveness of hedging relationships, for the purpose of applying hedge accounting (Accounting Guideline AcG-13). Specific documentation is required to qualify for hedge accounting prior to, at inception and throughout the term of the hedging relationship, including risk management policies, specific designation of hedging relationships, the nature of risk being hedged, the hedge objective or strategy, effectiveness assessment methodologies and accounting policies for hedge relationships, including income recognition. Retroactive and prospective effectiveness assessments will be required throughout the term of the hedge. The Company adopted the new accounting guideline prospectively beginning January 1, 2004, and adoption of the new guideline had no material effect on the Company's financial position or earnings in 2004.

Financial and Other Instruments

The Company utilizes natural gas commodity hedging contracts in order to manage the volatility inherent in the prices of its natural gas purchases. It also has utilized interest rate hedging contracts to reduce the volatility of the interest expense associated with its floating rate debt instruments. As of December 31, 2004 the Company had no interest rate hedging contracts outstanding.

During the second quarter of 2004 the Company completed its annual gas contracting and gas supply price management plan and filed it with the BCUC for review and acceptance. The BCUC accepted the plan as filed early in the third quarter of 2004. The plan called for gas price hedging, covering purchases over the period November 1, 2004 through October 31, 2005, to be completed in stages over the mid-July to mid-October 2004 period. Each hedging transaction was approved by the Company's price management committee.

At December 31, 2004, the Company had outstanding fixed price contracts covering approximately 3.2 million gigajoules of natural gas to be delivered in the months from January 2005 through October 2005 (representing approximately 21% of forecast annual system gas supply) at prices ranging from \$6.27 to \$9.87 per gigajoule. The fair value payable under the fixed price contracts at December 31, 2004 was \$3.9 million. In addition to the above

mentioned fixed price contracts, at December 31, 2004 the Company had also entered into natural gas price collar contracts to provide a ceiling and floor price for approximately 0.7 million gigajoules of natural gas to be delivered in the months of January and February of 2005 (representing approximately 5% of forecast 2005 system gas supply). The fair value payable under the collar contracts at December 31, 2004 was \$1.4 million. The fair value reflects the estimated amounts that the Company would pay at December 31, 2004 to terminate the fixed price contracts or collar contracts based on the estimated net cash flows under the terms of each contract.

Risks and Uncertainties

See “Risk Factors” for a discussion of risks affecting the Company’s business.

Outlook

The Company’s 2005 revenue requirements applications were filed with the BCUC in late 2004. The applications project that deliveries to residential and commercial customers will be 6% higher than experienced in 2004. Achieving the delivery forecast will be dependent upon a number of factors, including weather, the volatility and absolute level of gas prices and the relative prices of competitive fuels. Natural gas prices for 2005 for gas purchases by the Company, based on forward gas prices as at March 3, 2005, are forecast to be approximately 13% (\$0.84 per GJ) higher than the actual corresponding prices in 2004.

DIVIDENDS

Over the last two years the Company has paid regular quarterly cash dividends of \$0.20 per Common Share, payable on March 23, June 23, September 23 and December 23 of each year. The record date for the March 23, 2005 dividend on the Common Shares was March 4, 2005, and accordingly purchasers of the Offered Shares will not be entitled to this dividend. Over the last 30 years the Company has paid regular semi-annual cash dividends of \$0.84375 per Preferred Share, payable on January 1 and July 1 of each year. The declaration and payment of dividends are subject to the discretion of the Company’s board of directors and depend on, among other things, the Company’s financial condition, general business conditions and other factors which the Company’s board of directors considers to be relevant.

DESCRIPTION OF SHARE CAPITAL

The Offering consists of Common Shares in the capital of the Company. The Company’s authorized share capital consists of 6,020,000 Common Shares with a par value of \$2.50 each, 1,400,000 cumulative redeemable junior preferred shares with a par value of \$10 (the “Junior Preferred Shares”) and 200,000 6¾% cumulative redeemable preferred shares with a par value of \$25 each (the “Preferred Shares”). There are 3,612,780 Common Shares, no Junior Preferred Shares and 200,000 Preferred Shares issued and outstanding.

Common Shares

Each Common Share entitles the holder to one vote per share at all meetings of shareholders of the Company, except meetings at which only holders of another specified class of shares are entitled to vote. The Common Shares are the only issued voting securities of the Company and it has no securities outstanding that can be converted into voting or equity securities.

Cumulative Redeemable Junior Preferred Shares

The Junior Preferred Shares were issued in connection with a specific transaction, and to the extent issued have been redeemed and cancelled. No further Junior Preferred Shares will be issued.

6¾% Cumulative Redeemable Preferred Shares

The Preferred Shares are entitled to the payment of fixed cumulative preferential cash dividends at the rate of 6¾% per annum on the amounts from time to time paid up thereon as when declared by the board of directors of the Company, have priority in the event of the liquidation, dissolution or winding up of the Company over the Common Shares, are non-voting and are redeemable at the option of the Company at \$26 per share plus any accrued and unpaid dividends at the date of redemption. The Company may not create shares ranking prior to the Preferred Shares but may create and issue other shares ranking on parity with those shares.

Modification of Share Rights

Provisions as to the modification, amendment or variation of the rights attached to the Company's authorized capital are contained in the articles of the Company and the *Business Corporations Act* (British Columbia). The rights attached to any class may be varied or abrogated with the consent in writing of the holders of 75% of the issued shares of that class, or with a resolution passed at a separate meeting of the holders of the shares of that class by a majority of not less than 75% of the votes cast by holders entitled to vote at that separate meeting.

Constraints on Issuance of Securities

Under the Utilities Act, the approval of the BCUC is required for the issuance of shares (other than shares issued under an employee share purchase plan or employee share option plan filed with the BCUC) or the issuance of debt securities maturing one year or more from the date of issue.

Constraints on Share Ownership

Under the Utilities Act, the acquisition, directly or indirectly, by any one person, or by a person and associates of that person, of 20% or more of the outstanding Common Shares of the Company is a reviewable transaction requiring the prior approval of the BCUC.

CONSOLIDATED CAPITALIZATION

There has been no material change in the share and loan capital of the Company, on a consolidated basis, since December 31, 2004, the date of consolidated financial statements of the Company for the Company's most recently completed financial year contained in this prospectus.

OPTIONS TO PURCHASE SECURITIES

The following table sets out information regarding options to purchase securities of the Company that are outstanding as of April 1, 2005. Each of the options noted below was issued pursuant to the Company's Key Employee Stock Option Incentive Plan (the "Option Plan") and is exercisable for Common Shares.

<u>Category</u>	<u>Common Shares under Options Granted</u>	<u>Exercise Price (1)</u>	<u>Expiration Date</u>	<u>Market Value of Common Shares Underlying Options on Date of Grant (2)</u>	<u>Value of Options at April 1, 2005 (3)</u>
All executive officers and past executive officers (5 individuals)	15,700	\$20.00	November 7, 2005	\$20.50	\$ —
	11,100	18.75	March 14, 2006	19.00	7,215
	10,500	20.75	March 14, 2007	20.80	—
	8,500	30.50	March 24, 2008	30.50	—
	9,800	24.50	March 11, 2009	24.50	—
	18,900	15.50	March 16, 2010	15.60	73,710
	29,500	7.85	March 21, 2011	8.00	340,725
	11,700	6.50	April 27, 2011	6.50	150,930
	23,700	13.50	March 15, 2012	13.50	139,830
	30,000	13.50	July 4, 2012	13.31	177,000
	25,500	14.15	March 13, 2013	14.00	133,875
	19,200	20.80	March 2, 2014	20.75	—
All other employees and past employees	3,700	20.00	November 7, 2005	20.50	—
	2,100	18.75	March 14, 2006	19.00	1,365
	2,200	20.75	March 14, 2007	20.80	—
	3,000	30.50	March 24, 2008	30.50	—
	4,900	24.50	March 11, 2009	24.50	—
	6,300	15.50	March 16, 2010	15.60	24,570
	4,500	7.85	March 21, 2011	8.00	51,975
	8,500	13.50	March 15, 2012	13.50	50,150
	5,000	13.50	July 4, 2012	13.31	29,500
	8,200	14.15	March 13, 2013	14.00	43,050
	6,700	20.80	March 2, 2014	20.75	—
	<u>269,200</u>				

Notes:

- (1) The Option Plan provides that the exercise price of an option is the closing bid price of the Common Shares, as determined by trading on the Toronto Stock Exchange, on the day the option is granted.
- (2) The market value of Common Shares underlying options is the closing price of the Common Shares on the Toronto Stock Exchange on the date the option is granted.
- (3) The closing price of the Common Shares on the Toronto Stock Exchange on April 1, 2005 was \$19.40.

The Company provides long term incentives to the executives and other key employees of the Company and its subsidiaries through its Option Plan. Under the Option Plan, the Company's Human Resources and Compensation Committee may from time to time grant to officers and other key employees of the Company options to purchase Common Shares provided that the number of Common Shares reserved for issuance and which may be issued under the Plan or reserved for issuance under any other such options does not exceed 450,000 Common Shares. As at April 1, 2005, 321,380 Common Shares were reserved for issuance under the Option Plan. The exercise price of an option granted under the Plan is the closing bid price of the Common Shares, as determined by trading on the Toronto Stock Exchange, on the day an option is granted. The Option Plan provides that options may be granted for a term not exceeding ten years and are non-transferable and non-assignable, other than by will or by applicable law of descent. Options generally vest in five equal stages, with the first stage vesting on the date of the grant and the remainder in four equal annual stages commencing on the first anniversary of the date of the grant. The number of

Common Shares reserved for issuance to any one officer or key employee at any time cannot exceed 5% of the outstanding Common Shares on a non-diluted basis. The board of directors of the Company may from time to time, with the prior consent of the Toronto Stock Exchange, alter, suspend or discontinue the Option Plan. There is no specific requirement for approval of amendments by shareholders although any amendments to the Option Plan which are required by applicable laws to be approved by the shareholders of the Company are not effective until so approved.

PRIOR SALES

During the 12 months before the date of this prospectus, the Company issued the following Common Shares:

<u>Date</u>	<u>Number of Common Shares Issued (1)</u>	<u>Consideration Per Common Share</u>	<u>Aggregate Consideration</u>
November 23, 2004.....	2,000	\$ 6.50	\$13,000
November 26, 2004.....	1,000	6.50	6,500
November 30, 2004.....	2,000	6.50	13,000
January 26, 2005.....	4,000	7.85	31,400
January 27, 2005.....	3,200	7.85	25,120
April 6, 2005.....	700	7.85	5,495
April 6, 2005.....	400	13.50	5,400
April 6, 2005.....	900	14.15	12,735

Note:

(1) All Common Shares issued were issued upon the exercise of stock options granted pursuant to the Option Plan.

PRICE RANGE AND TRADING VOLUME

The Common Shares are listed on the Toronto Stock Exchange under the symbol “PNG”. The following table sets forth the high and low sales prices and trading volumes for the Common Shares on the Toronto Stock Exchange for the periods indicated:

<u>Calendar Period</u>	<u>High</u>	<u>Low</u>	<u>Volume</u>
2003			
First Quarter.....	\$18.50	\$14.00	183,927
Second Quarter.....	16.50	14.00	237,938
Third Quarter.....	17.65	16.00	113,533
Fourth Quarter.....	20.00	16.25	174,194
2004			
First Quarter.....	22.20	18.80	300,417
Second Quarter.....	21.25	18.10	159,782
Third Quarter.....	20.50	17.00	212,690
October.....	19.35	18.81	75,343
November.....	19.45	18.80	87,399
December.....	20.93	18.80	93,875
2005			
January.....	24.44	20.80	217,380
February.....	23.65	22.53	63,980
March.....	23.50	19.25	228,015
April (1 to 5).....	19.49	19.16	25,050

PRINCIPAL AND SELLING SHAREHOLDER

The following table sets forth, to the knowledge of the directors and executive officers of the Company, as of the date of this prospectus, information on the only persons or companies who beneficially own, directly or indirectly, or exercise control or direction over, more than 10% of the issued and outstanding Common Shares and information on the Selling Shareholder participating in the Offering.

<u>Shareholder</u>	<u>Ownership Before the Offering</u>			<u>Ownership After the Offering</u>	
	<u>Common Shares</u>	<u>Percentage (Non-Diluted/Fully Diluted)</u>	<u>Number of Common Shares to be Sold</u>	<u>Common Shares</u>	<u>Percentage (Non-Diluted/Fully Diluted)</u>
<u>Tricor Acquisition (STP) Inc.</u>	1,338,477	37.0%/36.4%	1,338,477(1)(2)	—	—

Notes:

- (1) The Selling Shareholder acquired these Common Shares on December 18, 2003.
- (2) Owned of record by the Selling Shareholder. The Selling Shareholder holds the Offered Shares to be sold by it as bare trustee and nominee for Tricor Pacific Capital Partners (Fund III), Limited Partnership (“Fund III”). Fund III, as beneficial owner, has directed Tricor to sell such Offered Shares, and the Selling Shareholder will receive and hold the net proceeds from such sale for the sole use, benefit and advantage of Fund III.

J. Trevor Johnstone, David J. Rowntree and Roderick R. Senft are directors of the Company and are directors and officers of the Selling Shareholder.

In 2003, the Selling Shareholder acquired 1,440,400 Common Shares of the Company from Westcoast Energy Inc. These shares represented a 40% economic interest in the Company. As part of the transaction, the Class B voting common shares of the Company (all of which were owned by Westcoast Energy Inc.) and all of the Class A non-voting shares of the Company were redesignated by Westcoast Energy Inc. as a single class of Common Shares with one vote per share. Certain executive officers of the Company acquired 101,923 of those Common Shares from the Selling Shareholder. Of these, 69,229 Common Shares were acquired using loans provided by the Selling Shareholder under loan and pledge agreements executed by each of such officers and the remaining 32,694 shares were acquired using personal funds provided by such officers. Under the loan and pledge agreements, each such officer has pledged his or her shares acquired utilizing the loans to the Selling Shareholder as security for payment of the loan.

USE OF PROCEEDS

The Offered Shares are being sold by the Selling Shareholder. The net proceeds to the Selling Shareholder from the Offering will be approximately \$24,268,130, after deducting the estimated expenses of the Offering and the Underwriters’ fee. The Company will not receive any part of the proceeds from the sale of the Offered Shares by the Selling Shareholder.

DIRECTORS AND OFFICERS

The following table sets out the name, municipality of residence, position, principal occupation and, if a director, the month and year upon which he became a director, for each of the directors and executive officers of the Company. Each of the directors holds office until the close of the next annual shareholders' meeting or until the director's earlier death, resignation or removal.

<u>Name and Municipality of Residence</u>	<u>Position</u>	<u>Principal Occupation</u>	<u>Director Since</u>
ROBERT F. CHASE (1)(2)(3) West Vancouver, British Columbia	Director, Chair	President & Chief Executive Officer of Lexacal Investment Corp. (an oil and gas services company)	April 26, 1995
ROY G. DYCE Coquitlam, British Columbia	Director, President & Chief Executive Officer	President & Chief Executive Officer of the Company	April 29, 1982
J. TREVOR JOHNSTONE (1)(4) West Vancouver, British Columbia	Director	Managing Director of Tricor Pacific Capital, Inc. (a private equity firm)	December 18, 2003
HUGH C. MORRIS (1)(5) Delta, British Columbia	Director	Chairman of Eldorado Gold Company (a gold producer and exploration company)	May 1, 1986
DAVID J. ROWNTREE (3)(5) West Vancouver, British Columbia	Director	Managing Director of Tricor Pacific Capital, Inc. (a private equity firm)	December 18, 2003
RODERICK R. SENFT (2) West Vancouver, British Columbia	Director	Managing Director of Tricor Pacific Capital, Inc. (a private equity firm)	December 18, 2003
DAVID G. UNRUH (4)(5) West Vancouver, British Columbia	Director	Vice Chairman & Director of Westcoast Energy Inc. (a natural gas gathering, processing and transmission company)	March 21, 2002
ARTHUR H. WILLMS (2)(3)(4) Vancouver, British Columbia	Director	Director of Westcoast Energy Inc. (a natural gas gathering, processing and transmission company)	April 28, 1983
GREG B. WEERES Delta, British Columbia	Vice President, Operations & Engineering	Vice President, Operations & Engineering of the Company	—
ELIZABETH A. FLETCHER Burnaby, British Columbia	Chief Financial Officer	Chief Financial Officer of the Company	—
KEVIN R. TEITGE Roberts Creek, British Columbia	Director, Corporate Development & Treasurer	Director, Corporate Development & Treasurer of the Company	—
CRAIG P. DONOHUE North Vancouver, British Columbia	Director, Regulatory Affairs & Gas Supply & Assistant Secretary	Director, Regulatory Affairs & Gas Supply & Assistant Secretary of the Company	—

Notes:

- (1) Member of the Audit Committee.
- (2) Member of the Executive Committee.
- (3) Member of the Human Resources and Compensation Committee.
- (4) Member of the Corporate Governance Committee.
- (5) Member of the Environment, Health and Safety Committee.

During the last five years, all of the directors and executive officers noted above have been employed in various capacities by the Company or by the companies indicated opposite their names except: Ms. Fletcher was Manager, Finance & Administration with Star Shipping (Canada) Ltd. (an international marine transportation company) prior to January 1999 until March 2000; and Mr. Teitge was an independent consultant from June 2003 through January 2004 and was Director, Corporate and Project Finance, Westcoast Energy Inc. (a natural gas gathering, processing and transmission company) prior to January 1999 until June 2003.

Messrs. Johnstone, Rowntree and Senft have advised the Company that they are prepared to continue to act as directors of the Company following the closing of the Offering, and accordingly have been proposed for re-appointment as directors in the Company's proxy circular for the annual general meeting to be held on April 28, 2005. The record date for the annual general meeting is March 18, 2005. As the Selling Shareholder was the shareholder of record on that date, the Selling Shareholder has agreed in the Underwriting Agreement not to vote any Offered Shares sold prior to the annual general meeting.

At April 1, 2005, the Company's directors and executive officers beneficially owned, directly or indirectly, or exercised control or direction over, an aggregate of 124,404 Common Shares, representing 3.4% of the then issued and outstanding Common Shares.

EXECUTIVE COMPENSATION

Summary Compensation Table

The following table sets forth a summary of the compensation earned in respect of the last three financial years by any individual who served as Chief Executive Officer or Chief Financial Officer of the Company during the most recently completed financial year, and each of the three most highly compensated executive officers of the Company, other than the Chief Executive Officer and Chief Financial Officer, who were serving as executive officers of the Company at the end of the most recently completed financial year and whose salary and bonus exceeds \$150,000 (collectively, the “Named Executives”).

<u>Name</u>	<u>Year</u>	<u>Salary</u> (\$)	<u>Bonus (1)</u> (\$)	<u>Other Annual Compensation (2)</u> (\$)	<u>Securities Awarded Under Options/SARs Granted (3)</u> (#)	<u>All Other Compensation (4)</u> (\$)
Roy G. Dyce President & Chief Executive Officer	2004	229,915	62,200	—	10,600	16,240
	2003	215,000	74,360	—	14,300	16,310
	2002	200,082	159,995	—	28,800	15,129
Elizabeth A. Fletcher (5) Chief Financial Officer	2004	74,448	10,470	—	2,500	4,030
	2003	123,173	25,710	—	3,100	9,807
	2002	109,674	74,530	—	8,100	6,461
Greg B. Weeres Vice President, Operations & Engineering	2004	149,746	28,580	2,750 (6)	3,700	9,036
	2003	140,000	34,587	3,250 (6)	5,000	2,424
	2002	132,115	80,590	2,750 (6)	8,700	2,300
Kevin R. Teitge (5) Director, Corporate Development & Treasurer	2004	132,021	12,800	—	—	5,017
	2003	—	—	—	—	—
	2002	—	—	—	—	—
Craig P. Donohue Director, Regulatory Affairs & Gas Supply & Assistant Secretary	2004	129,808	19,690	—	2,400	8,540
	2003	115,000	20,429	—	3,100	9,125
	2002	109,674	72,380	—	8,100	6,843

Notes:

- (1) Includes retention bonuses paid in fiscal 2002 as follows: Mr. Dyce — \$75,000; Ms. Fletcher — \$40,000; Mr. Weeres — \$40,000; and Mr. Donohue — \$40,000.
- (2) Perquisites and benefits for the financial year do not exceed the lesser of \$50,000 and 10% of the total annual salary and bonus for any Named Executive.
- (3) All securities awarded to Named Executives under options granted are Common Shares. To date, the Company has not granted stock appreciation rights (SARs) to the Named Executives.
- (4) Represents defined contribution pension and matching contributions made by the Company to employee savings plans on behalf of the Named Executive.
- (5) Mr. Teitge was President of a company which provided advisory services to the Company from June 1, 2003 to January 31, 2004 for which compensation of \$60,000 was paid. He worked for the Company as a contract employee from February 1, 2004 to April 30, 2004 and became a permanent employee of the Company effective May 1, 2004. He acted as Interim Chief Financial Officer while Ms. Fletcher was on maternity leave from February 13, 2004 to August 31, 2004.
- (6) Represents deemed interest on an interest-free housing loan.

Options/SAR Grants During the Most Recently Completed Financial Year

The following table sets out information for each Named Executive respecting the stock options granted to them under the Option Plan during the financial year ended December 31, 2004. To date, the Company has not granted stock appreciation rights (SARs) to the Named Executives.

Name	Securities Under Options/SARs Granted (1)	Percent of Total Options/SARs Granted to All Employees in Financial Year	Exercise Price or Base Price	Market Value of Securities Underlying Options/SARs on the Date of Grant	Expiration Date
	(#)	(%)	(\$/Security)	(\$/Security)	
Roy G. Dyce	10,600	40.93	20.80	20.80	March 2, 2014
Elizabeth A. Fletcher	2,500	9.65	20.80	20.80	March 2, 2014
Greg B. Weeres	3,700	14.29	20.80	20.80	March 2, 2014
Craig P. Donohue	2,400	9.27	20.80	20.80	March 2, 2014

Note:

(1) All securities under options granted are Common Shares and were granted pursuant to the Option Plan.

Aggregated Option/SAR Exercises During the Most Recently Completed Financial Year and Financial Year-End Option/SAR Values

The following table sets out for each Named Executive information respecting the options exercised by them during the financial year ended December 31, 2004 and the unexercised stock options held by them as at December 31, 2004, the financial year end:

Name	Securities Acquired on Exercise (1)	Aggregate Value Realized	Unexercised Options/SARs at FY-End		Value of Unexercised In-the-Money Options/SARs at FY-End (2)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
			(#)	(#)	(\$)	(\$)
Roy G. Dyce	12,500	186,063	89,660	27,040	418,716	158,625
Elizabeth A. Fletcher	—	—	19,200	6,100	184,500	35,164
Greg B. Weeres	—	—	23,240	8,660	201,169	47,679
Craig P. Donohue	—	—	24,680	6,020	182,594	35,154

Notes:

(1) All securities acquired on exercise are Common Shares.

(2) The closing price of the Common Shares on the Toronto Stock Exchange on December 31, 2004 was \$20.93.

Defined Benefit Pension Plan

The Company provides retirement benefits in the form of pensions for the Company's salaried employees through a pension plan registered under the Tax Act. The Named Executives are accruing benefits under the defined benefit provision of the plan. The defined benefit provision provides an annual retirement income commencing at retirement age equal to 2% of highest earnings (1% for Mr. Teitge) multiplied by credited service on and after July 1, 1999 (after January 1, 2004 for Ms. Fletcher). A different formula applies to credited service prior to July 1, 1999. Retirement age is age 65 and highest earnings is the highest annual average of basic salary plus 100% of bonuses paid pursuant to the Company's Annual Incentive Plan received in a 36 consecutive month period prior to retirement age. However, under the Tax Act the maximum annual retirement income payable from the plan is currently limited to \$2,000 multiplied by credited service. The number of years of credited service at retirement age 65 for the Named Executives participating in the defined benefit provision would be: 42.7 years for Mr. Dyce, 21.1 years for Ms. Fletcher, 27.7 years for Mr. Weeres, 20.1 years for Mr. Teitge, and 38.3 years for Mr. Donohue.

Mr. Dyce, Mr. Weeres and Ms. Fletcher are also members of the Company's Supplemental Executive Retirement Plan ("SERP"). The SERP provides for the payment of a supplementary retirement income such that the total retirement income is equal to the formula described above without limitation to the maximum annual retirement income prescribed under the Tax Act. All other employees may be eligible for benefits under a

supplemental plan similar to the SERP, except the total retirement income is limited to \$3,500 multiplied by credited service.

The estimated annual defined benefit retirement income payable at the normal retirement age of 65 is \$160,000 for Mr. Dyce, \$79,000 for Mr. Weeres, \$84,000 for Mr. Donohue, \$55,000 for Ms. Fletcher, and \$25,000 for Mr. Teitge.

For service prior to January 1, 2004, Ms. Fletcher participated in the defined contribution provision of the plan. Under the defined contribution provision, the Company makes annual contributions ranging from 2% to 8% of earnings to an account maintained for the executive under the plan. The Company's contributions vary depending on the executive's age and years of service. The executive directs the investment of the contributions made by the Company in a range of professionally managed investment funds. The executive's income at retirement age is dependent on the funds accumulated in the executive's account at that time.

Termination of Employment, Change in Responsibilities and Employment Contracts

The Company has severance compensation agreements with each of Ms. Fletcher, Mr. Weeres and Mr. Donohue. The agreements provide that, in the event of the termination of employment other than for cause, the Company shall pay a severance payment to the applicable Named Executive in an amount equal to his or her annual compensation at the time of termination for a specified notice period, in the case of Ms. Fletcher equal to 12 months, Mr. Weeres equal to 18 months and Mr. Donohue equal to 20 months.

The Company has an employment letter with Mr. Teitge which indicates that he will be provided with a severance compensation agreement that provides for a severance payment equal to 12 months salary in the event of termination of employment other than for cause.

Compensation of Directors

The Company pays its directors an annual retainer of \$10,000, plus \$1,000 for attending each board or committee meeting. The chair of the board of directors of the Company is paid an additional annual retainer of \$10,000, and the chair of each committee of the board of directors of the Company is paid an additional annual retainer of \$5,000. The foregoing fees are not paid to any director who is also a full-time employee of the Company. The Company also reimburses directors for reasonable out-of-pocket expenses incurred in attending meetings.

Directors and Officers Liability Insurance

The Company maintains directors and officers insurance. This insurance provides coverage of \$25 million for the policy period from December 18, 2004 to December 18, 2005, in respect of potential claims against the Company's directors and officers and in respect of losses for which the Company may be required or permitted by law to indemnify such directors and officers, subject to a deductible of \$250,000. The Company's articles also provide for indemnification of its directors and officers against expenses incurred in a proceeding in respect of the execution of the duties of their office and that are not the result of their wilful neglect or default. Each of the directors and executive officers of the Company has also entered into an agreement with the Company providing for indemnification by the Company.

INDEBTEDNESS OF DIRECTORS AND EXECUTIVE OFFICERS

No individual who is, or at any time during the financial year of the Company ended December 31, 2004 was, a director or executive of the Company, and no associate of such individual, is indebted to the Company or any of its subsidiaries or to another entity where such indebtedness is the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Company or any of its subsidiaries, other than routine indebtedness.

PLAN OF DISTRIBUTION

Under a registration rights agreement (the “Registration Rights Agreement”) dated December 18, 2003 between the Company and the Selling Shareholder, the Selling Shareholder has the right to request that the Company prepare and file a prospectus to qualify for distribution under Canadian securities laws the Common Shares held by the Selling Shareholder. The Selling Shareholder made such a request with respect to its 1,338,477 Common Shares on March 11, 2005. The Registration Rights Agreement provides that the Selling Shareholder will pay the Underwriters’ fee in respect of the Selling Shareholder’s shares and certain expenses of the Offering.

Pursuant to an underwriting agreement (the “Underwriting Agreement”) dated March 15, 2005, among the Company, the Selling Shareholder, Scotia Capital Inc. and CIBC World Markets Inc., the Selling Shareholder agreed to sell and the Underwriters agreed to purchase all but not less than all 1,338,477 Offered Shares on the Closing Date, subject to the terms and conditions set out in the Underwriting Agreement, at a price of \$19.40 per share, payable in cash to the Selling Shareholder against delivery. The Company will not receive any part of the proceeds from the sale of the Offered Shares by the Selling Shareholder. The Underwriting Agreement provides that the Selling Shareholder will pay the Underwriters a fee of \$0.97 per share sold in consideration for their services in connection with the Offering.

The terms and pricing of the Offering were determined solely by negotiation between the Selling Shareholder and the Underwriters.

The obligations of the Underwriters under the Underwriting Agreement are conditional and may be terminated in certain stated circumstances and upon the occurrence of certain stated events. The Underwriters are, however, severally obligated to take up and pay for all of the Offered Shares if any of the Offered Shares are purchased under the Underwriting Agreement. Pursuant to the Registration Rights Agreement, the Company agreed to indemnify the Selling Shareholder against certain liabilities. Under the terms of the Underwriting Agreement, the Underwriters may be entitled to indemnification by the Company and the Selling Shareholder against certain liabilities, including certain liabilities arising out of or based upon any misrepresentation in this prospectus.

The Company’s annual general meeting will be held on April 28, 2005, and the record date for that meeting is March 18, 2005. As the Offering will not be completed until after the record date, purchasers of the Offered Shares will not be entitled to vote those shares at the meeting or any adjournment thereof. The Selling Shareholder will have the legal right to vote the Offered Shares at the meeting but has agreed in the Underwriting Agreement not to vote any Offered Shares sold prior to the meeting.

Subscriptions for the Offered Shares will be received subject to rejection or allotment in whole or in part, and the right is reserved to close the subscription books at any time without notice.

The Offered Shares have not been and will not be registered under the United States Securities Act of 1933, as amended (the “U.S. Securities Act”) or the securities laws of any state in the United States and may not be offered or sold in the United States or to, or for the benefit of, U.S. persons (as defined in Regulation S under the U.S. Securities Act).

Pursuant to policy statements of the securities regulatory authorities in the Provinces of Ontario and Quebec, the Underwriters may not, throughout the period of distribution, bid for or purchase Common Shares. The foregoing restriction is subject to exceptions, on the condition that the bid or purchase is not engaged in for the purpose of creating actual or apparent active trading in, or raising the price of the Common Shares. These exceptions include a bid or purchase permitted under the rules of the applicable regulatory authorities relating to market stabilization and passive market making activities and a bid or purchase made for and on behalf of a customer where the order was not solicited during the period of distribution. Under the first mentioned exception, in connection with the Offering, the Underwriters may effect transactions which stabilize or maintain the market price of the Common Shares at levels other than those which might otherwise prevail in the open market. Those transactions, if commenced, may be discontinued at any time.

RISK FACTORS

Prospective investors should carefully consider the risks described below before making an investment decision. Prospective investors should also refer to the other information in this prospectus, including the Company's financial statements and the related notes. The risks and uncertainties described below are not the only risks and uncertainties the Company faces. Additional risks and uncertainties not currently known to the Company or that the Company currently deems immaterial also may impair the Company's business operations. If any of the following risks actually occur, the Company's business, results of operations and financial condition could suffer. In that event, the trading price of the Common Shares could decline, and an investor may lose all or part of his or her investment in the Common Shares.

Potential for Termination of Large Industrial Contracts

In 2004, approximately 75% of energy deliveries were made to PNG's three largest industrial customers, representing approximately 33% of the consolidated operating margin of PNG. PNG's contract with Methanex expires in 2009 and may be terminated prior to that date upon payment of an amount described in the contract. In 2004, deliveries to Methanex accounted for 25% of operating margin. PNG's contract with West Fraser expires in 2013 and may be terminated prior to that date upon payment of an amount described in the contract, or without payment in certain circumstances. In 2004, deliveries to West Fraser accounted for 5% of operating margin. See "Business of PNG — Large Industrial Customers". PNG's ability to negotiate new contracts and to renegotiate existing contracts could be impacted by factors it cannot control, including reduced demand due to higher gas prices, the financial strength of major customers and the availability of alternative energy sources. The risk of non-performance by one or more of the large industrial customers may be analyzed and managed, but it cannot be entirely eliminated.

PNG's service area is dependent upon industrial customers for its economic stability. These customers produce commodities that are subject to world commodity fluctuations. PNG's gas deliveries to these customers have been and may in the future be affected by their ability to continue to operate during sustained periods of low commodity prices. A prolonged decline in a sector affects all customer classes. For example, in the Western region many of PNG's industrial customers are involved in the forest sector. A prolonged decline in the forest sector could negatively impact gas deliveries to a lumber mill, as well as negatively impacting delivery requirements of commercial and residential customers who directly or indirectly provide services to that mill.

Conversion to an Income Trust Requires Regulatory and Other Approvals

In January 2004, PNG filed an application with the BCUC for approval to reorganize PNG's business into an income trust structure. In July 2004, following a public hearing process, the BCUC issued a decision denying the application. After a review of the BCUC decision by management of PNG, a new application to convert to an income trust structure was filed with the BCUC in December 2004. While management believes the new application addresses the concerns raised by the BCUC in its denial of the first application, there can be no assurance that the BCUC will provide the required approvals in order for the conversion to an income trust structure to be completed or, if so, on what terms. If BCUC approval is obtained, there can be no assurance that the required shareholder or court approvals for the conversion to an income trust will be obtained, that the contemplated agreement by PNG's debentureholders allowing early redemption will be obtained, or that there will be satisfactory market conditions for the proposed initial public offering of units by the new income trust. See "Business of PNG — Application to the BCUC to Convert the Company to an Income Trust Structure".

Liquidity, Cash Flow and Capital Availability Risks

In January 2005 PNG arranged new credit facilities which include a \$20 million operating line and a \$15 million risk management facility. The new operating line is subject to borrowing base requirements which may restrict the amount that PNG can borrow under the line at any point in time. In addition, the credit facilities are also subject to financial covenants that may act to restrict the amount PNG can borrow under the operating line. The credit facilities also contain a restriction on payments that may have the effect of reducing or eliminating the dividends that PNG can pay in the absence of access to new long term debt. See "Management's Discussion and Analysis — Capital Resources — Short Term Debt". Further, in the event that PNG is not successful in converting to an income trust structure, it does not expect to have access to new long term debt unless its current business risks

are reduced. See “Business of PNG — Application to the BCUC to Convert the Company to an Income Trust Structure”.

PNG is currently relying on operating cash flow to fund capital expenditures, scheduled amortization of long term debt and payment of dividends. While operating cash flow is currently adequate for those purposes, there is no assurance that it will be in the future. In the event that operating cash flow is not adequate to meet all of these purposes, it is likely that dividends on Common Shares would be reduced or eliminated until alternative funding was secured or other refinancing steps were taken.

Commodity Price and Supply Risks

Over the last three years, the commodity cost of natural gas has been highly volatile. The average cost of natural gas in 2004 remained at the historically high level experienced in 2003, which was more than 60% higher than in 2002. When prices are high, the prospect of fuel-switching and increased energy conservation poses a risk, as other energy sources can become more cost competitive. Fluctuations in the price of natural gas may increase PNG’s working capital financing requirements and related costs for accounts receivable, and may give rise to higher bad debt costs.

Adequate supplies of natural gas may not be available to satisfy committed obligations as a result of economic events, natural occurrences or counterparty failure to perform.

Usage Risks

Natural gas competes with other forms of energy available to PNG’s customers and end-users, including electricity, wood and coal and, in the case of certain industrial customers, wood waste. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors affect the demand for natural gas in the areas served by PNG. In addition, because electricity prices in British Columbia for residential and certain other customer classes have been set based primarily on the historical average cost of production, they have remained artificially low compared to market priced natural gas. Over time, this distortion in pricing signals may affect decisions by British Columbia consumers, potentially decreasing the use of natural gas by customers.

Over the past several years the average amount of natural gas consumed by residential customers has declined. This decline is attributable to a number of factors, including the replacement of older heating equipment by newer, more efficient equipment, more energy efficient housing, and energy conservation measures in response to higher gas prices and poor economic conditions in the Western region.

Regulatory Risks

PNG’s business and assets are subject to regulation by the BCUC. Changes in the regulatory environment may be beyond PNG’s control and may impact the viability of the business, including PNG’s ability to sustain or increase its profitability.

As part of the regulatory process, PNG maintains a number of deferral accounts including the GCVA, the RSAM and accounts for pipeline repair and rehabilitation. See “Business of PNG”.

The GCVA is utilized to record variances in PNG’s actual purchase cost of gas relative to the gas supply cost recovery charge included in customers’ rates. At times, the gas supply cost recovery charges included in customers’ rates can be below the actual purchase cost of gas, resulting in a significant balance in the account which must be recovered from customers in future rates.

PNG’s rates are set on the basis of forecast gas deliveries using normal heating degree days. To the extent that actual degree days are less than normal (that is, the weather is warmer than normal), revenues may be less than forecast. The revenue for residential and small commercial customers is protected by the RSAM deferral account approved by the BCUC in 2003 to record differences between forecast and actual deliveries. When deliveries to customers are less than forecast, there may be significant balances in the account which are subject to recovery in future rates to customers.

The BCUC requires PNG to record certain temporary pipeline repair and rehabilitation costs in deferral accounts for amortization into customer rates over a period of ten years on the basis that the customers benefit from such expenditures over that period of time.

The recovery of PNG's accumulated deferral accounts has an impact on PNG's liquidity requirements. Recovery of the deferral accounts through rates charged to customers is dependent upon regulatory approval and the ability to set rates high enough to recover such balances while maintaining the competitiveness of retail gas prices, and is therefore at risk.

Facility and Insurance Risks

PNG carries on business in a geographic area of British Columbia where a large portion of its pipeline transmission system is located in difficult terrain and where outages have been experienced in the past. Depending on circumstances, any such outages in the future may result in loss of revenues or increased maintenance or capital costs.

PNG maintains insurance against exposure to the physical loss of its pipeline, compressors and other above ground facilities, as well as loss of earnings insurance relating to revenues from its large industrial customers. Based on past insurance claims by PNG for damage to its pipeline caused by slides, washouts and other natural events, its deductibles have increased. Depending on the number and severity of any future outages, the financial impact on PNG could be material.

These facility and insurance risks could affect PNG's liquidity, and regulatory approval would be required for PNG to recover related costs through future rate adjustments.

Environmental and Safety Risks

PNG is required to comply with existing environmental laws and regulations. It is possible that increasingly strict environmental laws, regulations and enforcement policies, and potential claims for damages and injuries to property, employees, other persons and the environment resulting from current or discontinued operations, could result in substantial costs and liabilities in the future. In particular, PNG could be exposed to significant operational disruptions and environmental liability in the event of an accident involving natural gas. PNG believes that it has taken all reasonable and prudent steps to minimize its exposure in the case of safety or environmental incidents.

The Government of Canada ratified the Kyoto Protocol on December 17, 2002. No final decisions have been made on the targets, measures and regulations for industry sectors and companies to ensure compliance, and development of the methodology is currently in flux. It is not possible at this time to measure the extent of the impact of the Kyoto Protocol on PNG.

Derivatives Risks

PNG utilizes derivative and other financial instruments in connection with the management of gas supply prices and interest rates. PNG enters into forward, future, swap, fixed price and option contracts to manage the impact of market fluctuations on assets, liabilities or other contractual commitments. PNG could, however, incur financial losses in the future as a result of market or price volatility. Furthermore, because the valuation of these financial instruments can involve estimates, changes in the assumptions underlying these estimates can occur, changing PNG's valuation and potentially resulting in financial losses. This risk could affect PNG's liquidity, and regulatory approval would be required for PNG to recover related costs through future rate adjustments.

Human Resources Risks

Most of the employees of PNG are members of the Union. PNG's collective bargaining agreement with its Union expired on October 31, 2004. PNG and the Union have signed a memorandum of agreement regarding a new three year collective agreement. The memorandum of agreement was subject to a ratification vote by the unionized employees. On April 1, 2005, PNG was advised by the Union that the memorandum of agreement had been ratified. See "Business of PNG — Engineering and Operations — Employees". While the memorandum of agreement covers the three year period commencing November 1, 2004, labour disruptions associated with the collective bargaining process could in future impact upon PNG's ongoing operations. In addition, PNG is dependent on maintaining its ability to attract and retain employees with the requisite skill and capabilities to operate in the complex and competitive energy industry.

Aboriginal Matters

Aboriginal groups have claimed aboriginal and treaty rights over a substantial portion of the lands on which PNG's facilities and the gas supply areas served by those facilities are located. The existence of these claims, which range from the assertion of rights of limited use to aboriginal title, has given rise to some uncertainty regarding access to these lands. As well, approximately three kilometres of PNG's main pipeline and approximately nine kilometres of lateral transmission pipelines cross reserves established under the *Indian Act* (Canada). The impact upon PNG of treaties or settlements with aboriginal groups is uncertain.

Share Price Volatility

A number of factors could influence the volatility in the trading of the Common Shares, including changes in the economy or in the financial markets, industry-related developments, the impact of changes in PNG's operations and regulatory decisions affecting PNG, including decisions relating to return on equity, deemed equity component and the ability of the Company to convert to an income trust structure. Each of these factors could lead to increased volatility in the market price of the Common Shares. In addition, variations in earnings estimates by securities analysts and the market prices of the securities of companies in the same industry as PNG may also lead to fluctuations in the trading price of the Common Shares.

LEGAL PROCEEDINGS

Except as described below, there are no legal proceedings material to the Company to which the Company or any of its subsidiaries is a party or of which any of their respective property is the subject matter, and there are no such proceedings known to management of the Company to be contemplated.

On April 22, 2003, PNG(NE) commenced an action in the Supreme Court of British Columbia against Samson Canada, Ltd. (the "Defendant"), claiming damages for breach of contract and restitution for unjust enrichment relating to gas that PNG(NE) transported for the Defendant to two gas well production facilities over approximately two years. PNG(NE) claimed that the Defendant was obligated to but did not nominate and arrange for the delivery of gas to PNG(NE) to offset the gas that PNG(NE) delivered to the Defendant. On June 25, 2003, the Defendant filed a statement of defence in which it claimed that it was not the original party to the gas transportation agreement and therefore was not obligated to compensate PNG(NE) for the gas or, in the alternative, the provisions of PNG(NE)'s gas tariffs restrict PNG(NE)'s entitlement to compensation to one year. PNG(NE) and the Defendant are in the process of discovery with respect to the claims and a trial date has been set for October 2005. Approximately \$1.6 million has been included by the Company in its consolidated accounts receivable at December 31, 2004, reflecting management's estimate of the amount ultimately recoverable. However, the amount ultimately recovered may be materially different from management's estimate.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

To the knowledge of management of the Company, none of the current directors, executive officers or the principal shareholder of the Company, nor any associate or affiliate of those directors, officers or the principal shareholder, has had any direct or indirect material interest in any transaction within the three years before the date of this prospectus, or in any proposed transaction, that has materially affected or would materially affect the Company or any of its subsidiaries.

RELATIONSHIP BETWEEN COMPANY, SELLING SHAREHOLDER AND UNDERWRITERS

An affiliate of CIBC World Markets Inc. is a minority investor in the investment fund of Tricor Pacific Capital Inc. that holds the Selling Shareholder's investment in the Company. The affiliate does not have representation on the board of directors of Tricor Pacific Capital Inc. or on the board of directors of the investment fund that holds the interest in the Company.

The merchant bank affiliate of Scotia Capital Inc. (RoyNat Capital Inc.), holds debentures previously issued by the Company. As of December 31, 2004, the amount outstanding under these debentures was \$20,520,000. The Company is currently in compliance with the terms of the debentures. None of the proceeds from the Offering will be paid to the Company, nor will any proceeds be used to reduce amounts outstanding under the debentures. The Underwriters will not receive any benefit in connection with the Offering other than receipt of the Underwriters' fee,

which is payable by the Selling Shareholder. RoyNat Capital Inc. did not have any involvement in the decision to distribute the Offered Shares or the negotiation of the terms of this Offering.

The Company has engaged both Scotia Capital Inc. and CIBC World Markets Inc. to assist the Company in its application to the BCUC for approval to reorganize the Company's business as an income trust structure. See "Business of PNG — Application to BCUC to Convert the Company to an Income Trust Structure". As the Company will not receive any proceeds from this Offering, neither of the Underwriters will receive any benefit from the Offering in their capacity as advisors to the Company.

Notwithstanding any of the foregoing relationships, both of the Underwriters are "independent underwriters" for purposes of applicable Canadian securities laws.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Company are Deloitte & Touche LLP, Chartered Accountants, 2800-1055 Dunsmuir Street, Vancouver, British Columbia. The Company's transfer agent is Computershare Trust Company of Canada with registers maintained in Vancouver, Calgary, Regina, Winnipeg, Toronto and Montreal.

MATERIAL CONTRACTS

The only material contract entered into by the Company or a subsidiary of the Company during the past two years, other than in the ordinary course of business, is the Underwriting Agreement, described under "Plan of Distribution". A copy of the Underwriting Agreement may be examined during normal business hours at the offices of the Company located at Suite 950, 1185 West Georgia Street, Vancouver, British Columbia, during the period of distribution of the Common Shares or may be viewed at the website maintained by the Canadian Securities Administrators at <http://www.sedar.com>.

EXPERTS

Certain legal matters relating to the Common Shares offered by this prospectus will be passed upon on behalf of the Company by Farris, Vaughan, Wills & Murphy LLP, on behalf of the Selling Shareholder by Blake, Cassels & Graydon LLP, and on behalf of the Underwriters by Borden Ladner Gervais LLP.

At the date of this prospectus, the partners and associates of each of Farris, Vaughan, Wills & Murphy LLP, Blake, Cassels & Graydon LLP, and Borden Ladner Gervais LLP beneficially owned, directly or indirectly, less than 1% of the securities of the Company.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that such remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal advisor.

Auditors' Report

To the Board of Directors of
Pacific Northern Gas Ltd.

We have audited the consolidated balance sheets of Pacific Northern Gas Ltd. as at December 31, 2004 and 2003 and the consolidated statements of income, retained earnings and cash flow for each of the years in the three year period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flow for each of the years in the three year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

(signed) DELOITTE & TOUCHE LLP
Chartered Accountants
Vancouver, Canada
January 28, 2005 (except for Note 18 for
which the date is April 6, 2005)

PACIFIC NORTHERN GAS LTD.
CONSOLIDATED BALANCE SHEETS
As at December 31

	2004	2003
	[000's]	
ASSETS [notes 6 and 7]		
Current assets		
Cash and short-term investments	\$ —	\$ 313
Accounts receivable [notes 2, 11 and 14]	23,304	25,100
Income taxes recoverable [note 4]	362	—
Inventories of supplies and natural gas	1,725	2,215
Prepaid expenses	215	133
	25,606	27,761
Plant, property and equipment [note 3]	176,780	174,348
Deferred charges		
Debt costs	754	915
Rate stabilization adjustment mechanism	1,788	864
Pipeline rehabilitation costs	1,128	1,093
Other	1,601	1,433
	5,271	4,305
	207,657	206,414
LIABILITIES		
Current liabilities		
Bank indebtedness [note 6]	6,046	2,900
Accounts payable and accrued liabilities [note 11]	16,037	15,113
Gas purchase variance payable	2,232	3,279
Income and other taxes payable	2,726	2,737
Long term debt due within one year [note 7]	4,382	4,382
	31,423	28,411
Non-current liabilities [note 5]	407	224
Long term debt [note 7]	81,447	85,827
Deferred income taxes [note 4]	15,430	15,430
	97,284	101,481
	128,707	129,892
SHAREHOLDERS' EQUITY		
Preferred shares [note 8]	5,000	5,000
Common shares [notes 9 and 10]	9,009	8,960
Contributed surplus [notes 9 and 10]	2,567	2,379
Retained earnings	62,374	60,183
	73,950	71,522
	78,950	76,522
	207,657	206,414
Commitments, guarantees and contingency [notes 13, 14 and 15]		
Subsequent event [note 18]		

On behalf of the Board:

(Signed) ROBERT F. CHASE
Director

(Signed) ARTHUR H. WILLMS
Director

See accompanying notes

PACIFIC NORTHERN GAS LTD.

CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31

	<u>2004</u>	<u>2003</u>	<u>2002</u>
		[000's]	
Operating revenues [notes 2 and 11]	\$ 137,755	\$ 133,727	\$ 109,063
Cost of sales [note 11]	88,954	84,417	56,820
	<u>48,801</u>	<u>49,310</u>	<u>52,243</u>
Operating and maintenance	12,093	12,387	13,885
Administrative and general	6,623	6,084	5,279
Amortization of deferred charges	763	503	1,700
Municipal and other taxes	3,941	3,982	4,259
Depreciation	7,877	7,873	7,953
	<u>31,297</u>	<u>30,829</u>	<u>33,076</u>
	17,504	18,481	19,167
Investment and other income	<u>38</u>	<u>56</u>	<u>50</u>
	<u>17,542</u>	<u>18,537</u>	<u>19,217</u>
Income deductions			
Interest on long term debt	7,564	7,536	6,868
Other	450	573	824
	<u>8,014</u>	<u>8,109</u>	<u>7,692</u>
Income before income taxes	<u>9,528</u>	<u>10,428</u>	<u>11,525</u>
Income taxes [note 4] — current	2,646	3,870	7,225
— deferred	1,474	890	(290)
	<u>4,120</u>	<u>4,760</u>	<u>6,935</u>
Net income for the year	<u><u>5,408</u></u>	<u><u>5,668</u></u>	<u><u>4,590</u></u>
For common shares			
Net income for the year	5,408	5,668	4,590
Dividends on preferred shares	337	337	337
Net income applicable to common shares, basic and diluted	<u><u>5,071</u></u>	<u><u>5,331</u></u>	<u><u>4,253</u></u>
Earnings per common share [note 1]			
Basic	1.41	1.49	1.20
Diluted	<u>1.38</u>	<u>1.46</u>	<u>1.18</u>
Weighted average number of common shares outstanding			
Basic	3,596,706	3,583,121	3,553,445
Diluted	<u>3,667,095</u>	<u>3,641,240</u>	<u>3,591,375</u>

See accompanying notes

PACIFIC NORTHERN GAS LTD.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS
Years ended December 31

	2004	2003	2002
		[000's]	
Balance, beginning of year	\$60,183	\$57,719	\$63,318
Net income for the year	5,408	5,668	4,590
	<u>65,591</u>	<u>63,387</u>	<u>67,908</u>
Preferred share dividends	337	337	337
Common share dividends	2,880	2,867	9,852
	<u>3,217</u>	<u>3,204</u>	<u>10,189</u>
Balance, end of year	<u>62,374</u>	<u>60,183</u>	<u>57,719</u>

See accompanying notes

PACIFIC NORTHERN GAS LTD.

CONSOLIDATED STATEMENTS OF CASH FLOW

Years ended December 31

	2004	2003	2002
		[000's]	
OPERATING ACTIVITIES			
Net income for the year	\$ 5,408	\$ 5,668	\$ 4,590
Add (deduct) items not involving cash:			
Deferred income taxes	1,474	890	(290)
Depreciation and amortization	8,800	8,452	9,727
Stock option expense [note 10]	93	56	—
Other	(1,116)	(913)	543
Operating cash flow	14,659	14,153	14,570
Non-cash working capital changes [note 16]	1,708	(1,926)	(1,776)
Net cash provided by operating activities	16,367	12,227	12,794
INVESTING ACTIVITIES			
Additions to plant, property and equipment	(11,276)	(5,406)	(5,965)
Increase in deferred charges	(1,096)	(2,519)	(372)
Net cash used by investing activities	(12,372)	(7,925)	(6,337)
FINANCING ACTIVITIES			
Increase (decrease) in bank indebtedness	3,146	2,900	(8,675)
Issue of long term debt	—	—	15,037
Repayment of long term debt	(4,380)	(3,895)	(2,623)
Issue of common shares [note 9]	143	36	220
Dividends paid	(3,217)	(13,057)	(506)
Net cash (used by) provided by financing activities	(4,308)	(14,016)	3,453
(Decrease) increase in cash and short-term investments during the year ..	(313)	(9,714)	9,910
Cash and short-term investments, beginning of year	313	10,027	117
Cash and short-term investments, end of year	—	313	10,027
Supplemental cash flow information [note 16]			

See accompanying notes

PACIFIC NORTHERN GAS LTD.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2004, 2003 and 2002

1. Summary of Accounting Policies

Regulation

Pacific Northern Gas Ltd. and its wholly owned subsidiary, Pacific Northern Gas (N.E.) Ltd., are regulated utilities engaged in the transportation and distribution of natural gas. Their accounting records and practices conform to the requirements of the British Columbia Utilities Commission (the "Commission"). The Commission exercises statutory authority over matters such as rates, including rate of return on equity and capital structure, construction and operation of facilities, accounting practices, tolls, charges and contractual agreements with customers. In order to comply with orders issued by the Commission, the timing of recognition of certain revenues and expenses may differ from that which would otherwise be required under Canadian generally accepted accounting principles. Significant differences include, but may not be limited to the following accounting policies:

- Property, plant and equipment and related depreciation rates [notes 1 and 3]
- Deferral accounts [note 1]
- Income taxes [notes 1 and 4]
- Employee future benefit plans for post-retirement non-pension benefits [notes 1 and 5]
- Hedges, derivatives and other financial instruments [notes 1 and 14]
- Asset retirement costs [note 1]

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

Consolidation

The consolidated financial statements include the accounts of Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (collectively the "Company").

Revenue recognition

Operating revenues include natural gas sales that are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading date to the end of the year. Operating revenues also include transportation services revenues that are recorded as service is provided, as well as sales of gas surplus to the needs of the Company's sales customers ("off system sales") that are recognized when the gas is delivered.

Cash and short-term investments

Cash and short-term investments are held for the purpose of meeting short-term cash commitments and include bank balances and term deposits with maturities of less than 90 days.

Inventories of supplies and natural gas

Inventories of supplies and line-pack natural gas are valued at the lower of cost determined on a first-in, first-out basis and net realizable value. Inventories of natural gas in storage are valued at the lower of average cost and net realizable value.

Included in, or deducted from, inventories of natural gas are amounts for natural gas to be received from, or returned to transportation service customers. This amount represents the difference between natural gas received on behalf of the transportation service customers and natural gas delivered to them.

Plant, property and equipment

Plant, property and equipment are recorded at cost less contributions in aid of construction. Cost includes an allowance for funds used during construction calculated at the Company's cost of capital. As directed by the Commission, the cost of depreciable assets retired, together with removal costs, less salvage is charged to accumulated depreciation. Gains or losses on disposal are not taken into income unless the disposal is outside the normal course of business or involves a major item of plant.

Depreciation is provided on a straight-line basis for plant in service at the commencement of each fiscal year at rates prescribed by the Commission. Average annual depreciation rates are as follows:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
	%	%	%
Transmission plant.....	2.7	2.9	2.9
Distribution plant.....	2.6	2.6	2.6
General plant.....	5.4	5.3	5.6
Processing plant.....	4.9	4.9	4.8
Composite rate.....	2.9	3.0	3.0

Deferral accounts

[a] Debt costs

Debt costs comprise issue costs of long term debt, which are amortized on a straight-line basis over the term of the related issue.

[b] Gas purchase variance payable

As directed by the Commission, gas purchase variance costs, which arise due to unanticipated commodity cost and demand fluctuations, are being charged or credited to cost of sales on a straight-line basis over periods ranging from one to three years. The amount of such credits included in cost of sales in 2004 was \$2,319,000 before income taxes [2003 — \$1,363,000; 2002 — \$1,254,000].

[c] Pipeline rehabilitation costs

In 2004, the Company deferred costs of \$193,000, net of income taxes, relating to temporary repairs of pipeline breaks [2003 — \$651,000; 2002 — \$222,000]. The ultimate realization of the 2004 deferred charges is subject to a future decision of the Commission.

As directed by the Commission, pipeline rehabilitation costs are being amortized on a straight-line basis over ten years. The total amount of amortization of pipeline rehabilitation costs in 2004 was \$158,000 [2003 — \$133,000; 2002 — \$204,000].

[d] Large Industrial Customer Margin Deferral

As directed by the Commission, a deferral account was set up to recover the lost margin from certain large industrial customers whose demand varied from expectations. Total credits of \$165,000 net of income tax, [2003 — costs of \$1,116,000; 2002 — costs of \$230,000] were deferred and included in other deferred charges. The amount deferred during the year ended December 31, 2003 is being amortized over three years. The amount deferred during the year ended December 31, 2002 was amortized over one year, in 2003. Amortization of \$372,000 has been included in net income during 2004 related to the costs deferred in 2003. The amount deferred during the year ended December 31, 2004 will be amortized commencing in 2005. The Company has applied to the Commission for a three-year amortization period for the 2004 deferral.

[e] Rate Stabilization Adjustment Mechanism

As directed by the Commission, the Company established a rate stabilization adjustment mechanism in 2003 to record the variance between actual and budgeted natural gas deliveries to residential and small commercial customers. The financial impact of the difference in deliveries is deferred for future recovery from or refund to the customers over a three-year period, commencing in the year following deferral. During 2004, \$1,206,000, net of income taxes, [2003 — \$864,000; 2002 — \$nil] was credited to income in respect of this deferral.

[f] Interest deferral

As directed by the Commission, the Company has a short and long term interest deferral mechanism that mitigates exposure to fluctuations in short term and long term interest rates for variable interest rate debt instruments. In 2004, interest of \$259,000, net of income taxes, was credited to deferred charges [2003 — credit of \$53,000; 2002 — debit of \$15,000], to be refunded to customers over a two year period commencing 2005.

[g] Propane air plant deferral

In 2004, the net book value of a propane air plant which is no longer in service with an undepreciated value of \$966,000 was removed from fixed assets and transferred to a deferral account for future recovery from customers over a period of twenty years commencing in 2005. The ultimate recovery of these deferred charges from customers is subject to a future decision of the Commission.

[h] Other

As directed by the Commission, various other costs have been deferred to be recovered from future revenues over periods ranging from 1 to 10 years. During 2004, \$404,000 [2003 — \$52,000; 2002 — \$1,312,000 credited] was charged to income, net of income taxes, in respect of these deferred costs.

Income taxes

The Company provides for income taxes using the income taxes currently payable method as directed by the Commission, except as described below. Under the income taxes currently payable method, no provisions are made for income taxes deferred as a result of differences in timing between the treatment for income tax and accounting purposes of various income and expenditure items [see note 4].

The Commission has directed that the deferral method of accounting for income taxes be followed for certain transactions within the Company. Under the deferral method of accounting for income taxes, reported earnings are charged with the income taxes related to those earnings. Differences between these taxes and taxes currently payable, arising mainly from differences in the timing of expense deductions, are recorded as deferred income taxes.

Employee future benefit plans

The Company accrues its pension obligations under employee benefit plans and the related costs, net of plan assets. The actuarial determination of the accrued benefit obligation uses the projected benefit method prorated on service (which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees, and other actuarial factors).

For the purpose of calculating the expected return on plan assets, those assets are valued at a market-related value. The market-related value of assets is determined as the average of the fair value of plan assets and four projected values. The projected values are determined by projecting the fair value as at a particular time (1 year, 2 years, 3 years and 4 years prior to the measurement date) to the measurement date using actual non-investment cash flows and an assumed investment return equal to the average market-related value return on three month T-Bills plus 2.5%.

Actuarial gains (losses) arise from the difference between actual long term rate of return on plan assets for a period and the expected long term rate of return on plan assets for the period, or from changes in actuarial assumptions used to determine the accrued benefit obligation. The excess of the net unamortized cumulative actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of the plan asset at the beginning of the year is amortized over the average remaining service period of the active employees. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The average remaining service period of the active employees covered by the pension plan is 14 years.

For the defined contribution plan maintained by the Company, contributions payable by the Company are expensed as pension costs.

Other retirement benefit plans are non-contributory health care and life insurance plans. Prior to 2004, the Company used the pay-as-you-go method of accounting for non-pension benefits as directed by the Commission. Beginning in 2004, both the current service cost and the benefits paid to retirees are expensed and recovered in customer rates. The accrued benefit obligation is included on the balance sheet in non-current liabilities.

Financial instruments

Derivative and other financial instruments are utilized in connection with management of gas supply and interest rates. The Company enters into forward, future, swap, fixed price and option contracts to manage the impact of market fluctuations on assets, liabilities, or other contractual commitments. The Company defers the impact of changes in the market value of these contracts until such time as the associated transaction is completed.

Credit risk is the risk of loss from non-performance of suppliers, customers or financial counterparties to a contract. The Company maintains credit policies which management believes significantly minimize overall credit risk. These policies include a review of a counterparty's financial condition, measurement of credit exposure and monitoring of concentration of exposure to any one customer or counterparty.

Earnings per common share

Basic earnings per common share are calculated using the weighted average number of common shares outstanding during the year. Diluted earnings per share are calculated using the treasury stock method whereby the weighted average number of common shares outstanding during the year is adjusted to reflect the potential exercise of dilutive share purchase options.

There are 84,200 [2003 — 71,500; 2002 — 102,700] stock options outstanding during the year that could potentially dilute basic earnings per share in the future that were not included in the computation of diluted earnings per share because the options' exercise price were greater than the average market price of the common shares.

Stock based compensation

The Company has a stock option plan as described in note 10. Effective January 1, 2003 the Company adopted the amended recommendations of the CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments". Under the amended standards of this Section, the fair value of all stock-based awards granted are estimated using the Black-Scholes model and are recorded in operations over their vesting periods. The compensation cost related to stock options granted after January 1, 2003 have been recorded in operations.

In 2002 the Company used the intrinsic valued based method to account for stock-based compensation transactions with employees. If the Company had used the fair-value based method to account for stock-based compensation, pro forma net income and earnings per common share would have been as follows:

		2002
		[\$000's, except per share amounts]
Net income	As reported	\$4,590
	Pro forma	\$4,488
Net income applicable to common shares	As reported	\$4,253
	Pro forma	\$4,151
Basic earnings per common share	As reported	\$ 1.20
	Pro forma	\$ 1.17
Diluted earnings per common share	As reported	\$ 1.18
	Pro forma	\$ 1.15

The Company did not include those options outstanding at January 1, 2002 in its assessment of the 2002 pro-forma impact disclosed above.

Changes in Accounting Policies

[a] Accounting for Asset Retirement Obligations

Effective January 1, 2004 the Company adopted, the recommendations in Section 3110 of the Canadian Institute of Chartered Accountants ("CICA") Handbook, "Asset Retirement Obligations" ("ARO"). The new standard requires companies to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of the fair value can be determined. The associated asset retirement cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted over the estimated useful life of the asset.

The Company's natural gas transmission and distribution long-lived assets are comprised principally of mains, service lines, compressors, and measuring and regulating equipment. Actual costs incurred for retirement and site restoration are charged to accumulated depreciation in accordance with regulatory treatment. The Company does not have a material legal retirement obligation for natural gas transmission and distribution long-lived assets and has not recorded an ARO liability.

[b] Impairment of long-lived assets

Effective January 1, 2004 the Company adopted the new recommendations in Section 3063 of the CICA Handbook, "Impairment of Long-Lived Assets". The section establishes the recognition, measurement and reporting standards with respect to the impairment of long-lived assets held for use. Pursuant to the recommendations, a loss of value should be recognized when the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. The adoption of these recommendations did not have a material impact on the financial statements of the Company.

[c] Hedging relationships

Effective January 1, 2004 the Company adopted the new Accounting Guideline 13, "Hedging Relationships", which specifies the circumstances in which hedge accounting is appropriate, including specific requirements relating to the identification, documentation, designation and measurement of the effectiveness of hedges. The guideline also identifies situations where hedge accounting is to be discontinued.

[d] Generally Accepted Accounting Principles

Effective January 1, 2004, the Company adopted the new recommendations in Section 1100 of the CICA Handbook, "Generally Accepted Accounting Principles". This Section establishes standards for financial reporting in accordance with Generally Accepted Accounting Principles ("GAAP"). It describes what constitutes GAAP and its sources and states that non-rate regulated entities should apply every primary source of GAAP that deals with the accounting and reporting in financial statements of transactions or events encountered by them. Where applicable, it also requires rate-regulated entities to disclose how the accounting policies adopted by them differ from the primary sources of GAAP. The adoption of these recommendations did not have any impact on the financial statement presentation or net income.

[e] Non-pension post retirement benefits

Effective January 1, 2004, the Company changed the method of expensing non-pension post-retirement benefits on a prospective basis. Prior to that date, only benefits paid were expensed. Beginning in 2004, and with the approval of the Commission, both the current service cost and the benefits paid are expensed. There was no effect on net income by adopting this new accounting policy in 2004, as the additional expense of \$180,000 was recovered from customers in rates.

Comparative figures

Certain of the prior year figures have been reclassified to conform to the current year's presentation.

2. Major Customers

The proportion of energy deliveries and operating revenues attributable to large industrial customers is as follows:

	2004		2003		2002	
	Energy	Operating revenues	Energy	Operating revenues	Energy	Operating revenues
	%	%	%	%	%	%
Methanex Corporation	67	9	65	9	65	19
West Fraser Mills Ltd., Alcan Inc. and British Columbia Hydro and Power Authority	8	6	8	8	9	6

At December 31, 2004, 9% [2003 — 8%; 2002 — 10%] of accounts receivable was attributable to these four customers. The Company is exposed to credit risk in the event of non-performance by customers, but does not anticipate such non-performance. The Company monitors the credit risk and credit rating of industrial customers on a regular basis. The maximum credit risk is the fair value of the accounts receivable.

3. Plant, Property and Equipment

	2004	2003
	[000's]	
Transmission plant	\$180,290	\$177,779
Distribution plant	84,330	82,713
General plant	21,309	20,095
Processing plant	633	553
Construction in progress	4,579	649
Total plant, property and equipment	<u>291,141</u>	<u>281,789</u>
Accumulated depreciation		
Transmission plant	74,142	69,389
Distribution plant	28,916	27,791
General plant	10,928	9,949
Processing plant	375	312
Total accumulated depreciation	<u>114,361</u>	<u>107,441</u>
	<u>176,780</u>	<u>174,348</u>

During the year, the Company received contributions in aid of construction of \$257,000 [2003 — \$176,000], which have been recorded as a reduction of distribution plant.

4. Income Taxes

Significant components of the Company's deferred tax liabilities are as follows:

	2004	2003
	[000's]	
Deferred income tax liabilities		
Capital cost allowance claimed for income tax purposes in excess of depreciation and amortization	\$14,462	\$14,462
Other	968	968
Deferred income tax liabilities	<u>15,430</u>	<u>15,430</u>

Income tax expense varies from the amount that would be expected if current rates were applied to income before income taxes for the following reasons:

	2004	2003	2002
	(Percent)		
Combined Canadian federal and provincial statutory income tax rates, including surtaxes	35.6	37.6	39.6
Increase (decrease) in income taxes resulting from:			
Large corporations tax	3.1	4.5	2.9
Depreciation in excess of capital cost allowance	7.0	6.6	5.9
Amortization of intangibles	3.1	1.8	5.9
Capitalized overhead deducted for tax purposes	(4.9)	(3.9)	—
Other items	(0.7)	(1.0)	5.8
Effective rate of income taxes	<u>43.2</u>	<u>45.6</u>	<u>60.1</u>

From July 1, 1978 until its suspension on November 1, 1986, the deferral method was followed by the Company. Had the deferral method of accounting for income taxes been followed continuously since the inception of the Company, the deferred income tax liabilities and deferred income tax expense (recovery) would be:

	<u>2004</u>	<u>2003</u>
	[000's]	
Unrecorded deferred tax liabilities		
— long term, beginning of year	\$14,805	\$15,084
Unrecorded deferred income tax (recovery) expense	(178)	(279)
Unrecorded deferred tax liabilities		
— long term, end of year	<u>14,627</u>	<u>14,805</u>
Deferred income tax liabilities, as reported	<u>15,430</u>	<u>15,430</u>
Total deferred income tax liabilities	<u><u>30,057</u></u>	<u><u>30,235</u></u>

5. Employee Future Benefit Plans

The Company and its subsidiary have a number of funded and unfunded defined benefit plans, as well as defined contribution plans, that provide pension, other retirement and post-employment health and life insurance benefits for most employees. Its defined benefit plans are based on years of service and average earnings.

The measurement dates of the funded plans, as well as the effective dates of the most recent actuarial valuations and the next required actuarial valuations for the purpose of funding the funded plans are as follows:

	<u>2004</u>	<u>2003</u>
Measurement date of the plan assets and accrued benefit obligation	September 30, 2004	September 30, 2003
Effective date of the most recent actuarial valuation report for funding purposes	December 31, 2003	January 1, 2001
Effective date of the next required actuarial valuation report for funding purposes	December 31, 2006	December 31, 2003

The following table shows the allocation of the pension plan assets at the measurement dates:

	<u>2004</u>	<u>2003</u>
Asset category:		
Cash and short-term notes	4.2%	0.3%
Accrued income receivables (payables)	—	(0.3%)
Canadian bonds	38.4%	33.9%
Canadian equities	33.8%	36.7%
Foreign equities	23.6%	29.4%
	<u><u>100.0%</u></u>	<u><u>100.0%</u></u>

Information about the defined benefit pension plans is as follows:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
		[000's]	
Accrued benefit obligations			
Balance, beginning of year	\$17,224	\$15,323	\$13,154
Current service cost	595	419	427
Employees' contributions	8	4	14
Interest cost	1,028	987	947
Benefits paid	(777)	(680)	(1,026)
Actuarial losses	1,157	1,171	1,807
Balance, as at measurement date	<u>19,235</u>	<u>17,224</u>	<u>15,323</u>
Plan assets			
Fair value, beginning of year	12,720	11,601	11,566
Actual return on plan assets	1,590	1,426	792
Employer contributions	497	369	255
Employees' contributions	8	4	14
Benefits paid	(777)	(680)	(1,026)
Fair value, as at measurement date	<u>14,038</u>	<u>12,720</u>	<u>11,601</u>
Funded status — plan deficit	(5,197)	(4,504)	(3,722)
Unamortized net actuarial losses	4,749	4,456	3,742
Unamortized past service costs	—	1	3
Unamortized transitional asset	(26)	(24)	(22)
Accrued benefit obligation as at measurement date	(474)	(71)	1
Employer contribution between measurement date and year end	593	109	112
Accrued benefit assets end of year	<u>119</u>	<u>38</u>	<u>113</u>

The following is a summary of the significant actuarial assumptions used in measuring the Company's accrued pension benefit obligations:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
		(Percent)	
Accrued benefit obligation as of December 31, with a measurement date of September 30:			
Discount rate	6.00%	6.00%	6.50%
Rate of compensation increase	3.25%	3.25%	3.25%
Benefit costs for years ended December 31, with a measurement date of September 30:			
Discount rate	6.00%	6.50%	6.50%
Expected long-term rate of return on plan assets	7.50%	7.75%	7.75%
Rate of compensation increase	3.25%	3.25%	3.25%

The Company's pension plan expense is as follows:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
		[000's]	
Current service cost	\$ 595	\$ 419	\$ 427
Interest cost	1,028	987	947
Expected return on plan assets	(930)	(1,116)	(987)
Amortization of past service costs	1	2	—
Amortization of net actuarial loss	214	40	—
Amortization of transitional asset	2	2	(9)
Net defined benefit pension plan expense	<u>910</u>	<u>334</u>	<u>378</u>
Defined contribution pension plan expense	46	49	75
Total pension expense	<u>956</u>	<u>383</u>	<u>453</u>

Information about the unfunded non-pension post-retirement benefit obligation is as follows:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
		[000's]	
Balance, beginning of year	\$ 4,739	\$ 4,167	\$ 2,093
Current service cost	180	160	71
Interest cost	284	273	154
Benefits paid	(192)	(101)	(71)
Actuarial loss (gain)	(849)	240	1,920
Balance, end of year	<u>4,162</u>	<u>4,739</u>	<u>4,167</u>
Funded status — plan deficit	(4,162)	(4,739)	(4,167)
Unamortized net actuarial losses	<u>3,982</u>	<u>4,739</u>	<u>4,167</u>
Accrued benefit obligation	<u>(180)</u>	<u>—</u>	<u>—</u>

Effective January 1, 2004, the Company changed the method of expensing non-pension post-retirement benefits on a prospective basis [note 1]. Prior to that date, only benefits paid were expensed. Beginning in 2004, both the current service cost and the benefits paid are expensed and recovered in customer rates. The accrued benefit obligation is included on the balance sheet in non-current liabilities.

The assumed extended health care cost trend used for measurement purpose is 10.0% per annum, grading down over 5 years to 5.0% and remaining at that level thereafter. The assumed dental premium trend used for measurement purposes is 7.0% per annum for the first 10 years and 6.0% per annum thereafter.

The Company's non-pension post-retirement benefit expense is as follows:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
		[000's]	
Current service cost	180	—	—
Benefits paid	<u>192</u>	<u>101</u>	<u>71</u>
Non-pension post-retirement benefit expense, as reported	372	101	71
Current service cost	—	160	71
Interest cost	284	273	154
Amortization of transitional obligation	123	123	123
Amortization of net actuarial loss	100	97	—
Less benefits paid, expensed above	<u>(192)</u>	<u>(101)</u>	<u>(71)</u>
Non-pension post-retirement benefit plan expense, accrual method	<u>687</u>	<u>653</u>	<u>348</u>

Total cash payments for employee future benefits are \$1,153,000 in 2004 [2003 — \$628,000; 2002 — \$434,000] consisting of cash contributed to funded pension plans, cash payments in respect of non-pension post-retirement benefits, and cash contributed to defined contribution pension plans.

6. Bank Indebtedness

	<u>2004</u>	<u>2003</u>
		[000's]
Bank overdraft	\$ 946	\$ —
Bank demand operating line of credit	<u>5,100</u>	<u>2,900</u>
Bank indebtedness	<u>6,046</u>	<u>2,900</u>

The Company has a bank demand operating and hedge line of credit of \$25 million [2003 — \$25 million] which bears interest at prime rate or bankers' acceptance rates [December 31, 2004 — 4.25%; December 31, 2003 — 4.5%] and provides funds for general corporate and working capital requirements. The amount available under this facility is subject to borrowing base requirements. The line of credit is collateralized by the pledge of a \$25 million debenture and a charge on certain accounts receivable and inventories. At December 31, 2004, the amount available under the facility was approximately \$6.4 million, \$6.1 million of which had been drawn. There were no outstanding letters of credit.

On January 24, 2005, a new operating line of credit was obtained from another lender, providing for bank demand operating and hedge lines of credit of \$ 35 million. The amount available under these facilities is subject to borrowing base requirements and has a term of 18 months. The new lines of credit are collateralized by the pledge of a \$40 million debenture and a charge on certain accounts receivable and inventories.

7. Long Term Debt

	<u>2004</u>	<u>2003</u>
	[000's]	
Secured Debentures [a]		
RoyNat Debenture due January 15, 2011, bearing interest at a floating rate [December 31, 2004 — 5.557%], payable in monthly instalments of \$110,000, with a final instalment of \$120,000 at maturity	\$ 8,040	\$ 9,360
RoyNat Debenture due December 15, 2012, bearing interest at a floating rate [December 31, 2004 — 6.057%], payable in monthly instalments of \$105,000, with a final instalment of \$2,505,000 at maturity . . .	12,480	13,740
2011 Series, 10.75% due December 13, 2011, payable in annual instalments of \$700,050, and \$800,000 in each of years 2009 and 2010 with a final instalment of \$5,000,000 at maturity	9,400	10,100
2018 Series, 8.75% due November 15, 2018, payable in annual instalments of \$600,000, commencing November 15, 1999 and \$1,000,000 in each of the years 2014 to 2017, with a final instalment of \$7,000,000 at maturity	16,400	17,000
2025 Series, 9.30% due July 18, 2025, payable in annual instalments of \$500,000, commencing July 18, 2004 with a final instalment of \$9,500,000 at maturity	19,500	20,000
2027 Series, 6.90% due December 2, 2027, payable in annual instalments of \$500,000, commencing December 2, 2006 with a final instalment of \$9,500,000 at maturity	20,000	20,000
Construction advances and other [b]	<u>9</u>	<u>9</u>
	85,829	90,209
Long term debt due within one year [c]	<u>4,382</u>	<u>4,382</u>
	<u>81,447</u>	<u>85,827</u>

[a] Collateral for the Secured Debentures consists of a specific first mortgage on substantially all of the Company's plant, property and equipment and gas purchases and gas sales contracts, and a first floating charge on other property, assets and undertakings.

[b] Advances have been received from certain industrial concerns to enable construction of the facilities required to provide natural gas service. This financing is non-interest bearing and will be repaid as these customers meet their commitments for the purchase of natural gas.

[c] Payments required to meet sinking fund and retirement provisions of long term debt during the next five years and thereafter are as follows:

	[000's]
2005	\$ 4,382
2006	4,882
2007	4,882
2008	4,882
2009	4,880
Thereafter	<u>61,921</u>
	<u>85,829</u>

8. Preferred Shares

	<u>2004</u>	<u>2003</u>
	[000's]	
Authorized		
1,400,000 cumulative redeemable junior preferred shares with a par value of \$10		
200,000 6.75% cumulative redeemable preferred shares with a par value of \$25 each		
Issued		
200,000 6.75% preferred shares	\$5,000	\$5,000

The 6.75% preferred shares are redeemable at the option of the Company at \$26 per share plus any accrued and unpaid dividends at the date of redemption.

9. Common Shares

	<u>2004</u>	<u>2003</u>
	[000's]	
Authorized		
6,020,000 Voting common shares with a par value of \$2.50 each		
Issued		
3,603,580 Common shares [2003 — 3,583,880]	\$9,009	\$8,960

During 2004, the Company issued 19,700 common shares [2003 — 4,800; 2002 — 31,300] for cash consideration of \$143,000 [2003 — \$36,000; 2002 — \$220,000] upon the exercise of employee options. Of this amount, \$94,000 [2003 — \$24,000; 2002 — \$141,000] has been credited to contributed surplus, representing the excess of the issue price over the par value of the shares.

On December 17, 2004, the Company filed an application with the Commission seeking the approvals required pursuant to the Utilities Commission Act to transfer the ownership of Pacific Northern from the current common shareholders to an income trust called the "PNG Income Trust". The PNG Income Trust would be owned by unit holders that would be comprised of the shareholders that exchange their common shares for units and new investors under an initial public offering of PNG Income Trust units. The application will be reviewed through a public hearing process, with a decision by the Commission expected in the second or third quarter of 2005. Any transfer of ownership would also require the approval of the shareholders of the Company, court approval, and acceptable market conditions.

10. Stock Option Plan

The Company has a stock option incentive plan under which share options are granted to certain of its employees. Share options are granted at an exercise price equal to the fair market value of the Company's common shares on the date of the grant.

Share options generally vest in five equal stages with the first stage vesting on the date of the grant, and the remainder in four equal annual stages commencing on the first anniversary of the date of the grant. The maximum term of options awarded is ten years.

As of December 31, 2004, there are 330,580 [2003 — 350,280; 2002 — 355,080] shares reserved for issuance pursuant to options that may be granted under the stock option incentive plan.

In 2004, 25,900 options were issued at an exercise price of \$20.80.

Commencing in 2003, the Company accounts for its grants under this plan in accordance with the fair value based method of accounting for stock-based compensation [note 1]. The compensation cost that has been charged against income (and credited to contributed surplus) in 2004 is \$93,000 [2003 — \$56,000].

The fair value of each option grant is estimated on the date of the grant using the Black-Scholes option pricing model with the following assumptions:

	<u>2004</u>	<u>2003</u>
Dividend yield	4%	4%
Expected volatility (annualized)	44%	44%
Risk free interest rate	3%	3%
Expected years of option life (average)	7.5	7.5

A summary of the changes to the Company's stock option plan during the years ended December 31, 2004, 2003 and 2002 is as follows:

	<u>2004</u>		<u>2003</u>		<u>2002</u>	
	<u>Number of shares</u>	<u>Weighted- average exercise price</u>	<u>Number of shares</u>	<u>Weighted- average exercise price</u>	<u>Number of shares</u>	<u>Weighted- average exercise price</u>
Outstanding at beginning of year	272,200	\$14.52	247,000	\$14.45	223,020	\$13.98
Granted	25,900	20.80	34,600	14.15	68,500	13.50
Exercised	(19,700)	7.28	(4,800)	7.52	(31,300)	7.00
Forfeited	—	—	—	—	(8,620)	14.60
Expired	—	—	(4,600)	14.13	(4,600)	14.13
Outstanding at end of year	<u>278,400</u>	<u>15.61</u>	<u>272,200</u>	<u>14.52</u>	<u>247,000</u>	<u>14.45</u>
Options exercisable at end of year	<u>212,600</u>	<u>15.78</u>	<u>197,260</u>	<u>15.38</u>	<u>112,610</u>	<u>18.39</u>
Weighted average remaining contractual life	<u>5.9 years</u>		<u>6.6 years</u>		<u>7.2 years</u>	

The following table summarizes information about the stock options outstanding and exercisable as at December 31, 2004:

<u>Expiry Date</u>	<u>Options Outstanding</u>	<u>Options Exercisable</u>	<u>Exercise Price</u>
November 7, 2005	19,400	19,400	\$20.00
March 14, 2006	13,200	13,200	18.75
March 14, 2007	12,700	12,700	20.75
March 24, 2008	11,500	11,500	30.50
March 11, 2009	14,700	14,700	24.50
March 16, 2010	25,200	25,200	15.50
March 21, 2011	41,900	30,980	7.85
April 27, 2011	11,700	11,700	6.50
March 15, 2012	32,600	19,200	13.50
July 4, 2012	35,000	35,000	13.50
March 13, 2013	34,600	13,840	14.15
March 2, 2014	25,900	5,180	20.80
	<u>278,400</u>	<u>212,600</u>	

11. Related Party Transactions

The Company's transactions with related parties are as follows:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
	[000's]		
Westcoast Energy Inc., parent company until December 18, 2003			
Transportation services received	\$—	\$ 876	\$ 834
Materials purchases and services received	—	463	588
Enlogix CIS L.P., a company related through common control until September 5, 2002			
Services received	—	—	510
Westcoast Energy Risk Inc., a company related through common control until December 18, 2003			
Services received	—	2,253	528
Duke Energy Marketing L.P., an entity related through common control from March 14, 2002 to December 18, 2003			
Natural gas purchases	—	19,385	2,034
Engage Energy Canada, L.P., an entity related through common control until December 18, 2003			
Natural gas purchases and services received	—	197	5,323
Natural gas sales	—	23,121	15,110

On December 18, 2003, all of the common shares of the Company held by Westcoast Energy Inc. were acquired by Tricor Pacific Capital, Inc.

Accounts payable and accrued liabilities as at December 31, 2003 include \$151,000 and accounts receivable at December 31, 2003 include \$647,000 relating to the above related party transactions.

These transactions were in the normal course of operations and were recorded at amounts established and agreed between the related parties, which approximate fair market value.

12. Fair Values of Financial Instruments

The fair values of debt instruments included in the consolidated balance sheets are as follows:

	<u>Carrying value</u>		<u>Fair value</u>	
	<u>2004</u>	<u>2003</u>	<u>2004</u>	<u>2003</u>
	[000's]		[000's]	
Long term debt	\$85,829	\$90,209	\$96,410	\$92,501

The fair value of the Company's long-term debt is estimated by reference to quoted market prices for actual or similar instruments.

The fair values of other financial instruments included in the consolidated balance sheets, including accounts receivable, bank indebtedness, and accounts payable and accrued liabilities approximate their carrying values due to their short term nature.

13. Natural Gas and Interest Rate Contracts

The Company's tolls are set using a forecasted price for gas. However, some of the Company's gas supply contracts contain pricing mechanisms that reflect monthly variations in the price of gas, rather than fixed prices.

At December 31, 2004, the Company had outstanding fixed price contracts covering approximately 3.2 million gigajoules of natural gas to be delivered in the months from January to October 2005 (representing approximately 23 percent of forecast 2005 system gas supply) at prices

ranging from \$6.27 to \$9.87 per gigajoule. In addition, to the above mentioned fixed price contracts, at December 31, 2004 the Company has also entered into natural gas price collar contracts to provide a ceiling and floor price for approximately 0.7 million gigajoules of natural gas to be delivered in the months of January and February of 2005 (representing approximately 5 percent of forecast 2005 system gas supply).

At December 31, 2003, the Company had outstanding fixed price contracts covering approximately 3.4 million gigajoules of natural gas to be delivered in the months from January to October 2004 at prices ranging from \$4.92 to \$6.66 per gigajoule. In addition, at December 31, 2003 the Company had also entered into natural gas price collar contracts to provide a ceiling and floor price for approximately 1.0 million gigajoules of natural gas to be delivered in the months of January, February and March of 2004.

The difference between the price of gas used for toll purposes and the actual cost of gas purchased is deferred and refunded to or recovered from customers as directed by the Commission.

The fair values (payable) receivable at December 31 under the contracts are as follows:

	<u>2004</u>	<u>2003</u>
	[000's]	
Fixed price contracts	\$(3,855)	\$1,041
Collar contracts	<u>(1,406)</u>	<u>(160)</u>
	<u>(5,261)</u>	<u>881</u>

The fair values reflect the estimated amounts that the Company would receive or pay at December 31 to terminate the fixed price and collar contracts, based on the estimated future net cash flows under the terms of each contract.

These estimated fair market values have no impact on earnings due to the regulated nature of the Company's operations. Based on the current regulatory process, any gains or losses arising from utility related financial instruments would be treated as part of the cost of service.

The Company's purchase commitments at December 31, 2004 under various gas supply contracts expiring through 2007 were as follows:

	[\$000's]
2005	41,678
2006	933
2007	103
Thereafter	—

14. Contingency and Measurement Uncertainty

Pacific Northern Gas (N.E.) Ltd. is involved in a dispute with a customer over the payment for gas transported. The dispute relates to the customer's obligation to supply its own gas for transportation to their facilities, or failing that, to pay for gas delivered to those facilities.

On May 27, 2003 the Company commenced an action in the Supreme Court of British Columbia against the customer (the "Defendant"), claiming damages for breach of contract and for restitution for unjust enrichment relating to an outstanding accounts receivable balance in the amount of approximately \$2,020,000. The Company claimed that the Defendant had nominated no gas into the pipeline during a specified time period and, accordingly, the Defendant was obligated to pay for gas delivered to the Defendant at specified rates.

On June 25, 2003, the Defendant filed a statement of defense in which it claimed that it was not the original party to the gas supply agreement at the time of the alleged deliveries and therefore not obligated to pay any back charges or, in the alternative, as the amount claimed represented a revision to the initial billings for gas deliveries, the provisions of the Company's gas tariffs restrict the period in which billing errors can be back charged to a customer.

On July 7, 2003, the Company filed a reply to the statement of defense in which it continued to assert its claim. The Company and the Defendant are still in the process of discovery with respect to the claims and a trial date has been set for October 2005.

The Company believes it has a substantial case for recovery of the amounts billed and has reduced the original accounts receivable to \$1.6 million which represents management's best estimate of the amount ultimately recoverable.

15. Commitments and Guarantees

Under the terms of its gas transportation and supply agreements with certain customers, the Company has provided an indemnity for all damages, claims or actions arising from any act or accident in connection with the installation, presence, maintenance and operations of the Company's property and equipment, or in connection with the presence of gas deemed to be in the possession and control of the Company, and carries insurance to cover losses in the event of any claims under these provisions. The Company has also provided an environmental indemnity to certain secured debenture holders for any losses arising from non-compliance by the Company with applicable environmental laws.

16. Supplemental Cash Flow Information

Non-cash working capital changes:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
		[000's]	
(Increase) decrease in:			
Accounts receivable	\$ 1,796	\$(3,864)	\$ 393
Income taxes recoverable	(362)	—	—
Inventories of supplies and natural gas	490	(850)	155
Prepaid expenses	(82)	67	580
Increase (decrease) in:			
Accounts payable and accrued liabilities	1,207	1,228	3,241
Gas purchase variance payable	(1,330)	601	2,678
Income and other taxes payable	(11)	892	(8,823)
Attributable to operating activities	<u>1,708</u>	<u>(1,926)</u>	<u>(1,776)</u>

Interest and tax payments:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
		[000's]	
Income taxes paid	\$2,993	\$3,690	\$15,136
Interest paid	7,269	7,877	7,289

Included in accounts payable and accrued liabilities at December 31, 2002 are dividends payable of \$9,852,000.

17. Segmented Information

The Company operates in one industry and geographic segment, the transmission and distribution of natural gas within Canada. The consolidated financial statements have therefore not been segmented.

18. Subsequent Event

The Company has filed a prospectus dated April 6, 2005 relating to the distribution of 1,338,477 common shares of the Company held by a significant shareholder of the Company. All costs of the sale of the shares will be borne by the selling shareholder and the Company will not receive any part of the proceeds from the sale of the shares.

GLOSSARY OF TERMS

“**10³m³**” is a measurement of natural gas by volume and means one thousand cubic metres.

“**Alcan**” means Alcan Smelters and Chemicals Ltd.

“**BC Hydro**” means the British Columbia Hydro and Power Authority.

“**BCUC**” means the British Columbia Utilities Commission.

“**CanWest**” means CanWest Gas Supply Inc.

“**CCAA**” means the *Companies’ Creditors Arrangement Act*.

“**CICA**” means the Canadian Institute of Chartered Accountants.

“**CNRL**” means Canadian Natural Resources Limited.

“**Closing**” means the closing of the Offering.

“**Common Shares**” means the common shares in the capital stock of the Company.

“**Company**” means Pacific Northern Gas Ltd., a company incorporated under the laws of the Province of British Columbia.

“**Duke Energy**” means Westcoast Energy Inc., doing business as Duke Energy Gas Transmission.

“**EBITDA**” means earnings before interest, income taxes, depreciation and amortization. See “Non-GAAP Measures”.

“**GAAP**” means generally accepted accounting principles in Canada.

“**GCVA**” means the gas cost variance account. See “Business of PNG — Government Regulation”.

“**gigajoule**” or “**GJ**” is a measurement of natural gas by energy.

“**heating degree days**” is a measure of how cold a location was over a period relative to a base temperature. The heating degree days for a single day are the number of degrees Celsius by which the average temperature in that day is below 18°C. The heating degree days for a longer period are the sum of daily heating degree days for days in that period.

“**ICDDA**” means the industrial customers deliveries deferral account. See “Business of PNG — Government Regulation”.

“**Kitimat LNG**” means Kitimat LNG Terminal.

“**LNG**” means liquefied natural gas.

“**Mcf**” is a measurement of natural gas by volume and means 1,000 cubic feet.

“**Methanex**” means Methanex Corporation.

“**MMcf**” is a measurement of natural gas by volume and means 1,000,000 cubic feet.

“**New Skeena**” means New Skeena Forest Products Inc.

“**Northeast region**” means the natural gas distribution utility in the northeast part of British Columbia owned and operated by PNG.

“**off system sales**” means gas sold to purchasers who are not transmission or distribution customers of PNG.

“**Offered Shares**” means the 1,338,477 Common Shares of the Selling Shareholder qualified by this prospectus.

“**Offering**” means the distribution by the Selling Shareholder of the Offered Shares pursuant to this prospectus.

“**operating margin**” means operating revenues less cost of sales. See “Non-GAAP Measures”.

“**Option Plan**” means the Company’s Key Employee Stock Option Incentive Plan.

“**petajoule**” or “**PJ**” is a measurement of natural gas by energy and means 1,000,000 gigajoules.

“**PNG**” means the Company and its subsidiaries, including PNG(NE).

“**PNG(NE)**” means Pacific Northern Gas (N.E.) Ltd., a wholly owned subsidiary of the Company.

“**Preferred Shares**” means the 6³/₄% cumulative redeemable preferred shares in the capital stock of the Company.

“Registration Rights Agreement” means the registration rights agreement dated December 18, 2003 between the Company and Tricor.

“ROE” means the after-tax return on the common equity component of the capital structure.

“RSAM” means the rate stabilization adjustment mechanism. See “Business of PNG — Government Regulation”.

“Selling Shareholder” means Tricor Acquisition (STP) Inc.

“SERP” means the Company’s Supplemental Executive Retirement Plan.

“Skeena” means Skeena Cellulose Inc.

“Tax Act” means the *Income Tax Act* (Canada) and the regulations thereunder.

“terajoule” or **“TJ”** is a measurement of natural gas by energy and means 1,000 gigajoules.

“Underwriters” means Scotia Capital Inc. and CIBC World Markets Inc.

“Underwriting Agreement” means the underwriting agreement dated March 15 2005, among the Company, the Selling Shareholder and the Underwriters.

“Union” means the International Brotherhood of Electrical Workers, which represents PNG’s unionized employees.

“Utilities Act” means the *Utilities Commission Act* (British Columbia).

“West Fraser” means West Fraser Mills Ltd.

“Western region” means the natural gas distribution and transmission utility in the west-central portion of northern British Columbia owned and operated by PNG.

CERTIFICATE OF THE COMPANY

Dated: April 6, 2005

The foregoing constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by Part 9 of the *Securities Act* (British Columbia), by Part 9 of the *Securities Act* (Alberta), by Part XI of *The Securities Act, 1988* (Saskatchewan), by Part VII of *The Securities Act* (Manitoba), by Part XV of the *Securities Act* (Ontario), by Part 6 of the *Securities Act* (New Brunswick), by Section 63 of the *Securities Act* (Nova Scotia), by Part II of the *Securities Act* (Prince Edward Island), by Part XIV of the *Securities Act* (Newfoundland and Labrador) and the respective regulations thereunder. This prospectus, as required by the *Securities Act* (Quebec) and the regulations thereunder, does not contain any misrepresentation likely to affect the value or the market price of the securities to be distributed.

By: (Signed) ROY G. DYCE
President and Chief Executive Officer

By: (Signed) ELIZABETH A. FLETCHER
Chief Financial Officer

On Behalf of the Board of Directors

By: (Signed) ROBERT F. CHASE
Director

By: (Signed) ARTHUR H. WILLMS
Director

CERTIFICATE OF THE UNDERWRITERS

Dated: April 6, 2005

To the best of our knowledge, information and belief, the foregoing constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by Part 9 of the *Securities Act* (British Columbia), by Part 9 of the *Securities Act* (Alberta), by Part XI of *The Securities Act, 1988* (Saskatchewan), by Part VII of *The Securities Act* (Manitoba), by Part XV of the *Securities Act* (Ontario), by Part 6 of the *Securities Act* (New Brunswick), by Section 64 of the *Securities Act* (Nova Scotia), by Part II of the *Securities Act* (Prince Edward Island), by Part XIV of the *Securities Act* (Newfoundland and Labrador) and the respective regulations thereunder. To our knowledge, this prospectus, as required by the *Securities Act* (Quebec) and the regulations thereunder, does not contain any misrepresentation likely to affect the value or the market price of the securities to be distributed.

SCOTIA CAPITAL INC.

CIBC WORLD MARKETS INC.

By: (Signed) DAVID BUSTOS

By: (Signed) ALAN C. WALLACE

AUDITORS' CONSENT

We have read the prospectus of Pacific Northern Gas Ltd. (the "Company") dated April 6, 2005 relating to the sale of 1,338,477 common shares of the Company. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the use in the above-mentioned prospectus of our report to the board of directors of the Company on the consolidated balance sheets of the Company as at December 31, 2004 and 2003 and the consolidated statements of income, retained earnings and cash flows for each of the years in the three-year period ended December 31, 2004. Our report is dated January 28, 2005 (except as to note 18, which is as of April 6, 2005).

(Signed) DELOITTE & TOUCHE LLP
Chartered Accountants

Vancouver, Canada
April 6, 2005

