



PACIFIC NORTHERN GAS LTD.

**ANNUAL
INFORMATION FORM**

For the period covering 12 months ending December 31, 2003

2004

April 23, 2004

TABLE OF CONTENTS

GLOSSARY	2
SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS	2
THE COMPANY	3
Development of the Business	3
BUSINESS OF THE COMPANY	4
Overview	4
Transmission Pipeline System	5
Distribution System	5
Northeast Region	6
Properties	6
Natural Gas Deliveries	6
Gas Sales and Transportation	7
Large Industrial Customers	7
Natural Gas Supply	9
Customer Additions	9
Government Regulation	10
General	10
Rate Regulation	10
Regulatory Activities	10
Engineering and Operations	13
Operating Activities	14
Liquidity and Capital Resources	14
Risk Factors	15
Concentration of Customer Base and Lack of Diversity	15
Commodity Price and Supply	15
Capital Availability	15
Regulatory Risk	16
Facility Risks	16
Insurance Risks	16
OTHER INFORMATION	17
SELECTED CONSOLIDATED FINANCIAL INFORMATION	18
MARKET FOR SECURITIES	19
DIRECTORS AND OFFICERS	19
ADDITIONAL INFORMATION	20

GLOSSARY

In this annual information form, *Gigajoule* (GJ) is equivalent to 0.94782 million British thermal units, *terajoule* (TJ) means one thousand GJ and *petajoule* (PJ) means one million GJ. One GJ is equivalent to approximately 0.9225 Mcf of gas. *Mcf* means one thousand cubic feet and *MMcf* means one million cubic feet. 10^3m^3 means one thousand cubic metres. In volumetric units, 1000 cubic metres is equivalent to 35.301 thousand cubic feet.

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain information provided and incorporated by reference in this annual information form may contain forward-looking statements that are subject to risks and uncertainties. Although the Company, as defined below, believes any such forward-looking statements are based on reasonable assumptions, no assurance can be given that every objective will be reached. The forward-looking statements may involve known and unknown risks, uncertainties and other factors which may cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, but are not limited to: general economic conditions; gas commodity price volatility; decisions by regulators; seasonal weather patterns; the cost and availability of capital; and the ability of the Company to attract and retain quality employees. Forward-looking statements, which involve assumptions and describe the Company's future plans, strategies and expectations, are generally identifiable by the words "may", "will", "should", "expect", "anticipate", "estimate", "believe", "intend" or "project" or the negative of these words or other variations of these words or comparable terminology. For further discussion see the section entitled "Risk Factors".

Any forward-looking statement speaks only as of the date on which it is made and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for the Company to predict which will arise after the date of this annual information form.

THE COMPANY

Pacific Northern Gas Ltd. (the "**Company**") was incorporated under the laws of British Columbia as a private company on October 28, 1965 and was converted to a public company on November 4, 1968. The head office of the Company is located at Suite 950, 1185 West Georgia Street, Vancouver, British Columbia, V6E 4E6 and its principal operating office is at 2900 Kerr Street, Terrace, British Columbia.

Pacific Northern Gas (N.E.) Ltd. ("**Pacific Northern (N.E.)**") is a wholly owned subsidiary of the Company with its main operating offices at 1208 – 102nd Avenue, Dawson Creek and 10016 – 104 Street, Fort St. John, British Columbia. PNG Marketing Ltd. (currently inactive) is a wholly owned subsidiary of the Company.

Development of the Business

The Company owns and operates a natural gas transmission and distribution utility operating within the west-central portion of northern British Columbia ("Western region"). Pacific Northern (N.E.) owns and operates a distribution utility in the northeast part of British Columbia ("Northeast region"). The utilities are separate stand-alone systems and both are regulated by the British Columbia Utilities Commission ("**BCUC**").

The business of the Company was essentially static in 2001 and 2002. In contrast, 2003 was an eventful year for the Company. The Company's financial position was strengthened by the establishment of a new operating and hedge line of credit, allowing the Company to improve its hedging program. In addition, the BCUC approved a rate stabilization adjustment mechanism for residential and small commercial customers that should mitigate the risk in forecasting deliveries. In early 2004 the Company also entered into a memorandum of agreement with one of its large industrial customers setting forth the principal terms of a new ten year transportation service agreement starting January 1, 2004. The agreement is subject to BCUC approval.

Economic conditions faced by the Company's customer base in the Western region continue to be weak, resulting in lower gas consumption in that area. The economy in the Northeast region is growing as a result of activity in the oil and gas exploration sector, which is reflected in customer additions in that area.

Prices for natural gas decreased in mid-2001 and price decreases were passed on to customers in October 2001, January 2002 and April 2002. Gas prices rose late in 2002 and continued to rise in 2003, resulting in rate increases on January 1 and April 1, 2003, then trended lower toward the end of 2003.

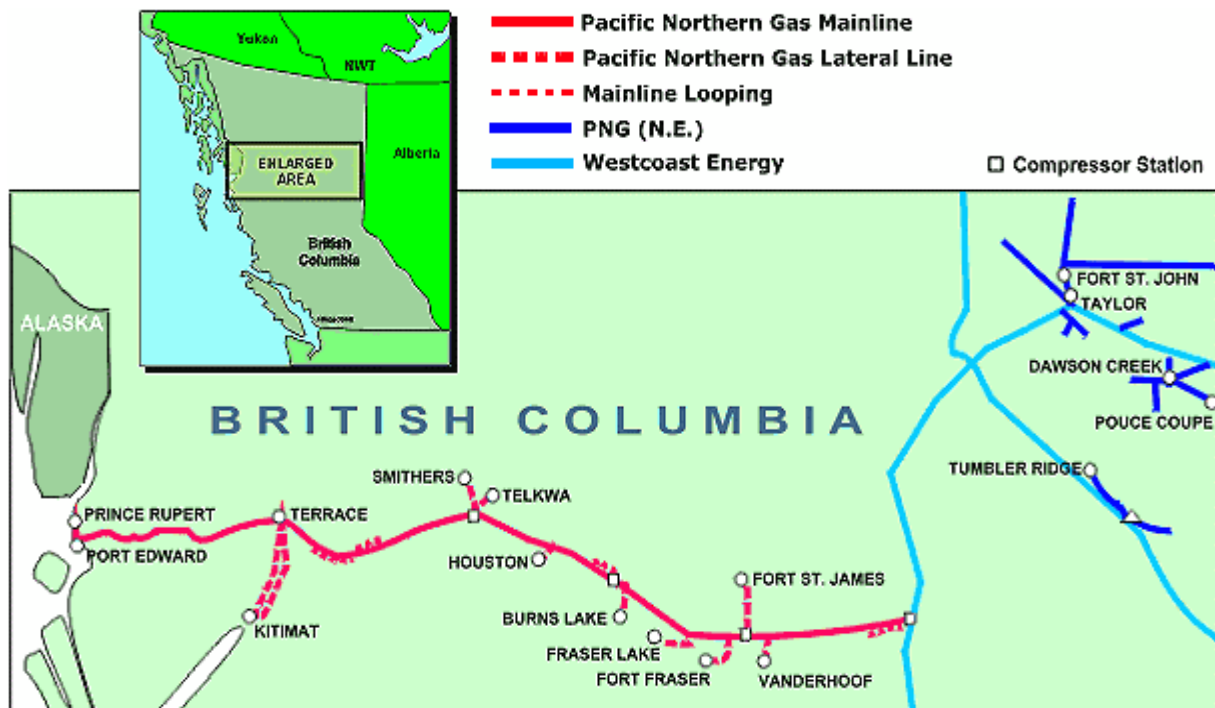
Tricor Acquisition (STP) Inc., a subsidiary of Tricor Pacific Capital, Inc. ("**Tricor**") acquired the Company's Class A non-voting and the Class B voting common shares held by Westcoast Energy Inc., effective December 18, 2003. In connection with the acquisition, all of the Company's Class A and Class B common shares were reclassified as one class of common shares with one vote per share. As a result of the acquisition, Tricor owns 37% of the outstanding common shares of the Company.

The Company submitted an application to the BCUC in January, 2004 seeking approval to recapitalize under an income trust ownership structure. This application was reviewed in a two day public hearing in April 2004. The decision on the application is expected to be rendered by the BCUC near the end of the second quarter.

BUSINESS OF THE COMPANY

Overview

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



The Company supplies gas to approximately 39,100 residential, commercial and industrial customers. The Company has four large industrial customers: Methanex Corporation (“**Methanex**”), West Fraser Mills Ltd. (“**West Fraser**”, formerly referred to as Eurocan), Alcan Smelters and Chemicals Ltd. (“**Alcan**”) and B.C. Hydro and Power Authority (“**BC Hydro**”). These four customers accounted for 73 percent of total gas deliveries and 25 percent of the Company's revenues during 2003.

Gas distributed by the Company to its residential and commercial customers and to certain industrial customers in 2003 was purchased under a long-term agreement with CanWest Gas Supply Inc. (“**CanWest**”) and under short-term agreements with other gas suppliers. Most of the Company's industrial customers satisfy their gas requirements by purchasing gas directly from producers or other gas suppliers and contracting with the Company for the transportation of that gas through the Company's pipeline systems. Accordingly, all of the firm gas requirements of the Company's large industrial customers and approximately 65 percent of the firm gas requirements of

the Company's small industrial customers are met through direct gas supply arrangements. Since the Company earns income from the transportation and distribution of gas and not from sale of gas as a commodity, it is not adversely affected by direct gas supply arrangements entered into by its customers.

Transmission Pipeline System

The Company's transmission pipeline system 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. The Company also owns and operates over 300 kilometres of lateral transmission pipelines extending into the various communities served by the Company, the most significant being dual lines extending approximately 57 kilometres into Kitimat.

Five compressor units maintain pressure on the Company'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

The Company owns and operates distribution facilities in the various communities located throughout its service area. The distribution service area consists of two regions. The Western region extends from Vanderhoof to Prince Rupert and Kitimat, and the Northeast region comprises the Tumbler Ridge, Dawson Creek and Fort St. John areas.

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 distribute natural gas within those municipalities. Each of the franchise agreements has an initial term of 21 years, expiring in 2011 (except in the case of Prince Rupert where the agreement expires in 2015), and is renewable at the option of either party for a further term of 21 years.

The Company also has operating agreements with the municipalities of Fraser Lake, Fort St. James and Telkwa that entitle it to install and operate gas distribution facilities in those municipalities. The initial term of each of the operating agreements expired in 1988, 1989 and 1991, respectively, and the Company is operating within the evergreen 10-year renewal terms of each agreement.

Under all of the municipal franchise and operating agreements, the Company is required to pay the municipality an annual fee on gas sales within the municipality equal to 3 percent of the Company's gross revenue from sales to residential and commercial customers and 3 percent of the gross revenue from the sale of the first $8\,500\,10^3\text{m}^3$ (300 MMcf) per year to any industrial customer.

The communities served by the Company's distribution system within its Western region had a total population of approximately 77,000 at December 31, 2003.

Northeast Region

The Pacific Northern (N.E.) system serves the Fort St. John and Dawson Creek area through connections between the Pacific Northern (N.E.) and Duke Energy pipeline systems at several locations. The system also connects with Canadian Natural Resources Limited's West Stoddart Pipeline 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, British Columbia to serve the Tumbler Ridge area. The entire system 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 6 to 8 MMcf per day. Pacific Northern (N.E.) 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. The agreements provide for payment of a 3 percent fee on gross revenues from sales to residential and commercial customers and 3 percent of the gross revenue from the sale of the first 8 500 10³m³ (300 MMcf) per year to any industrial customer. Pacific Northern (N.E.) currently operates its gas distribution facilities in the Tumbler Ridge area pursuant to an operating agreement under which no franchise fees are payable.

The communities served by the Company's distribution system within its Northeast region had a total population of approximately 47,000 at December 31, 2003.

Properties

Substantially all of the Company's transmission lines and lateral 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. Within all the municipalities in which the Company distributes gas, distribution lines occupy municipal streets and lanes by authority granted to the Company under franchise or operating agreements. 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 the Company in fee simple. The Company 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.

The Company's pipeline system is 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 (formerly Montreal Trust Company of Canada), as trustee, as amended and supplemented from time to time, under which the Company's Secured Debentures have been issued.

Natural Gas Deliveries

Total natural gas deliveries were 36.6 petajoules in 2003 compared with 39.5 petajoules in 2002. Transportation deliveries to large industrial customers decreased 8.9 percent from 2002 to 2003 due to a four-month labour dispute at West Fraser's Kitimat linerboard and kraft paper mill, and a five-week maintenance shutdown at the Kitimat methanol/ammonia facility of Methanex.

2003 deliveries to residential and commercial customers declined slightly from 2002 levels, which can be partially attributed to the weather being approximately 1% warmer in 2003 than in 2002.

Gas Sales and Transportation

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

	<u>2003</u>	<u>2002</u>	<u>2001</u>
<u>Deliveries</u> (in terajoules)			
Residential	3 464	3 503	3 470
Commercial	2 909	2 967	2 936
Small industrial	3 589	3 805	3 592
Large industrial	<u>26 676</u>	<u>29 188</u>	<u>21 783</u>
Total energy delivered	<u>36 638</u>	<u>39 463</u>	<u>31 781</u>
<u>Revenue</u> (in thousands)			
Residential	\$38,815	\$30,204	\$39,239
Commercial	28,378	22,395	29,827
Small industrial	9,545	9,479	10,539
Large industrial			
Methanex	12,343	20,590	20,427
West Fraser	3,373	3,091	3,543
Skeena	1,675	-	4,272
Alcan	5,605	3,832	4,489
BC Hydro	62	38	639
Off system sales	33,403	18,763	24,736
Other revenue	<u>528</u>	<u>671</u>	<u>884</u>
Total revenue	<u>\$133,727</u>	<u>\$109,063</u>	<u>\$138,595</u>
<u>Customers at year end</u>			
Residential	<u>34,132</u>	<u>34,251</u>	<u>34,241</u>
Commercial	4,931	4,941	4,927
Small industrial	38	58	57
Large industrial	<u>5</u>	<u>4</u>	<u>5</u>
Total number of customers	<u>39,106</u>	<u>39,254</u>	<u>39,230</u>

Large Industrial Customers

The Company has firm transportation service and interruptible sales agreements with Methanex, West Fraser and Alcan. The following table sets out certain information relating to the agreements with Methanex, West Fraser and Alcan:

<u>Customer</u>	<u>Expiry Date</u>	<u>Contract Demand Volume</u> ⁽¹⁾	<u>Minimum Volume</u> ⁽²⁾
Methanex	October 31, 2009	1 614.6 10 ³ m ³ (57.0 MMcf)	100%
West Fraser	October 31, 2004	192.4 10 ³ m ³ (6.8 MMcf)	75%
Alcan	October 31, 2005	30.8 10 ³ m ³ (1.1 MMcf)	85%

Notes:

(1) *Contract demand is the maximum volume of gas the Company is obligated to deliver each day on a firm basis.*

(2) *Stated as a percentage of the contract demand volume.*

These customers produce commodities that are subject to world commodity price fluctuations. The Company'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.

The Company delivers gas to its other large industrial customer, BC Hydro, under an interruptible sales/service agreement for electric power generation at BC Hydro's facility in Prince Rupert.

Deliveries to Methanex in 2003 accounted for approximately 65 percent of volumes delivered by the Company and approximately 9.3 percent of the Company's operating revenues. Transportation service to Methanex was made pursuant to an agreement that expires in October, 2009. An annual demand charge based on a firm toll of 50 cents per gigajoule applies over the term of the agreement. In addition, under the contract Methanex supplies a portion of the Company's internal gas requirements equal to four percent of deliveries to Methanex. The contract also includes a profit-sharing mechanism during periods of high methanol prices and relatively low gas prices.

The Company's 2003 rate application to the BCUC assumed a prospective new transportation contract with New Skeena Forest Products Inc. ("Skeena") for service to its pulp mill in Prince Rupert. It was expected that the pulp mill would operate for six months during 2003, however the plant failed to open in 2003. As a result, the Company recorded deferred charges in its industrial customer deliveries deferral account relating to Skeena. These charges will be amortized in rates and collected from customers over a three-year period beginning in 2004, subject to BCUC approval of the amortization period.

The transportation service and sales contracts with West Fraser and Alcan are in effect through October 31, 2004 and October 31, 2005, respectively. The agreement with Alcan will continue in effect past October 31, 2005 unless Alcan or the Company gives notice of termination.

In February 2004, the Company signed a memorandum of agreement with West Fraser for a new 10-year transportation contract with an effective date of January 1, 2004. The contract, which provides for a toll that is approximately 30 percent lower than the toll currently in effect, is subject to approval by the BCUC. During 2003, deliveries to West Fraser and Alcan accounted for 7.8 percent of the Company's total gas deliveries and 6.7 percent of operating revenues.

BC Hydro's electric generating facility in Prince Rupert has typically been used as a stand-by facility. Deliveries in 2003 were 22.1 terajoules, to maintain the facility in a ready to operate mode.

Natural Gas Supply

All of the Company's residential customers, most of its commercial customers and a number of its smaller industrial customers continue to rely on the Company for arrangement of their gas supply, and pay tariffs which include the Company'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.

The Company's larger customers typically arrange for their firm gas supplies and contract for transportation service on the Company's pipeline systems. These customers may also purchase gas from the Company when available supply is surplus to the needs of core market customers and may arrange interruptible transportation service if capacity is available on the system.

To meet the requirements of its core market customers, natural gas is purchased by the Company under long-term, seasonal and spot gas purchase contracts. Contracted gas that is surplus to the requirements of these customers in non-peak periods may be sold either on an interruptible basis to industrial customers or sold off-system. Most of the Company's contracted gas supply is produced in British Columbia.

Natural gas is purchased at prevailing market prices and passed through to customers without mark-up by the Company. The BCUC reviews the gas commodity portion of the Company'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 the Company 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, the Company 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 Company's gas supply is comprised of the pooled gas stream available from the Duke Energy pipeline system. This includes all of the supply to the Company's transmission line serving its Western region service area and approximately 73 percent 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, Fort St. John is served through two interconnections of the Pacific Northern (N.E.) pipeline system and Canadian Natural Resources Limited's West Stoddart pipeline system. In Dawson Creek approximately 24 percent of the required supply is received from a local producer of sweet (pipeline quality) gas at a point where its gas producing system intersects the Company'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 the Company operates its own gas processing facilities.

A long-term contract with CanWest accounted for about 67 percent of 2003 purchases. Other supplies included purchases under seasonal and spot arrangements.

Customer Additions

In 2003, 284 new services were connected to the Company's distribution systems, compared with 270 in 2002. This increase in service additions is the result of continued strong economic activity in the Northeast region. Although 284 new services were connected, the Company experienced a net

loss of 148 customers. This is a result of 432 customers leaving the distribution system, primarily in the Western region.

There are few remaining candidates for conversion to natural gas in the existing building stock and limited remaining opportunity 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

The Company is subject to regulation under the *Utilities Commission Act* of British Columbia (the "Act"). Pursuant to the 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 the Company to its customers, and that such rates are sufficient to yield the Company a fair and reasonable compensation for its services or a fair and reasonable return upon the value of its property.

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

Rate Regulation

The Company's rates are determined by the BCUC on a fixed rate method, under which rates are set on the basis of forecasts of both the cost of service and throughput for the Company'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 the Company's system, including operating, maintenance and administrative expenses, depreciation of facilities, income and other taxes and a return on rate base. Rate base is the aggregate of the depreciated cost of property, plant and equipment that is used or useful in serving the public and a reasonable allowance for working capital. The BCUC determines the allowable return on rate base after considering a variety of factors, including the degree of risk associated with the Company's business and the cost of capital.

Revenue requirements applications for all service areas 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.

Regulatory Activities

In November 2002, the Company filed applications with the BCUC for approval of new rates to be effective January 1, 2003 for all service areas. The 2003 revenue requirements application for the Western region was considered by the BCUC through an alternative dispute resolution process. A written hearing process was conducted by the BCUC in respect of the Northeast

region 2003 revenue requirements applications for the Fort St. John/Dawson Creek and Tumbler Ridge divisions of Pacific Northern (N.E.).

A settlement agreement was reached on the Western region's 2003 revenue requirements application on February 21, 2003. The 2003 allowed rate of return on common equity was 10.17 percent and it applied to a deemed common equity component of 36 percent. The allowed rate of return on common equity is set at 75 basis points above the low risk benchmark utility rate of return set by the BCUC's automatic return on equity formula.

The BCUC issued the Fort. St. John/Dawson Creek and Tumbler Ridge divisions' 2003 revenue requirements decisions on March 27, 2003. The 2003 allowed rate of return on common equity was 9.82 percent for the Fort St. John/Dawson Creek division and 10.07 percent for the Tumbler Ridge division which is 40 basis points and 65 basis points above the low risk benchmark utility rate of return, respectively. The, common equity component of rate base was deemed at 36 percent for both divisions.

In 2003, the Company received approval for a new deferral account for all regulatory divisions to record variances between projected and actual gas consumption by residential and small commercial customers (a Rate Stabilization Adjustment Mechanism, or "RSAM"). The objective of the RSAM deferral account is to manage the forecast risk associated with weather and other factors affecting gas consumption. If the actual gas use per customer account varies from the forecast average use per account approved by the BCUC, the financial impact of the difference is deferred for future recovery or refund to the customer.

Western Region

For 2003, the BCUC continued its direction to defer the difference between actual sales to Methanex, Skeena, West Fraser and B.C. Hydro and the forecast sales used by the Company in its revenue requirement application in an Industrial Customers Deliveries Deferral Account ("ICDDA"). Alcan was included in the 2003 ICDDA under the settlement terms of the 2003 revenue requirements application. The BCUC also accepted the Company's forecast of gas supply costs for 2003. Rate riders were approved in various amounts for 2003 to refund a credit balance accumulated in the gas purchase variance payable account.

The 2004 revenue requirements application for the Western region was filed with the BCUC at the end of November 2003. The application reflected an increase to the delivery charges offset by a reduction in the gas supply commodity charges. The 2004 forecast of gas supply commodity charges made at the end of November 2003 were approximately 19 percent lower than what was embedded in 2003 rates at that time. The BCUC approved the decreased gas supply commodity cost component of rates on a permanent basis, effective January 1, 2004 and approved the delivery charge increases on an interim basis.

The Company's 2004 revenue requirements applications project that deliveries to residential and small commercial customers in the Western region will be 2.7 percent higher than experienced in 2003. 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 2004 for gas purchases by the Company, based on forward gas prices as at February 24, 2004, are forecast to be approximately 2 percent (\$0.14 per GJ) higher than the actual corresponding prices in 2003.

In December 2003, the BCUC confirmed that its formula for determining the allowable return on common equity in 2004 resulted in a 9.15 percent return for a low risk benchmark utility for the year. The Company is seeking Commission approval to continue with a return on equity risk premium of 75 basis points for the Western region which would result in an allowable return on common equity of 9.90 percent for 2004. The BCUC approved interim rates effective January 1, 2004 were based on the 9.90 percent return on equity figure and a deemed 36 percent common equity component of the capital structure.

In February 2004 the Company filed an update to its 2004 revenue requirements application reflecting, among other things, the memorandum of agreement signed with West Fraser for a new transportation service contract effective January 1, 2004. The agreement, which is subject to approval by the BCUC, provides for a transportation toll that is approximately 30 percent lower than in effect under the current contract with West Fraser. The update to the application contained adjustments to other customers' rates required to ensure the Company would remain revenue neutral if the agreement is approved by the BCUC as filed.

The Western region 2004 revenue requirements application and the memorandum of agreement with West Fraser was the subject of a two day public hearing on March 31 and April 1, 2004. The BCUC's decision is expected to be issued late in the second quarter of 2004.

Northeast Region - Tumbler Ridge Division

The Tumbler Ridge 2004 revenue requirements application was filed with the BCUC at the end of November 2003. The application sought BCUC approval to decrease the gas delivery charge component of rates primarily due to lower projected gas requirements for internal company use. The gas commodity charge component of rates also decreased. The BCUC approved interim rates, effective January 1, 2004, resulting in rate decreases of approximately nine percent for residential and small commercial customers.

Northeast Region - Fort St. John/Dawson Creek Division

The BCUC accepted the Company's forecast of gas supply costs for 2003. Rate riders were approved for 2003 to recover debit balances recorded in the gas purchase variance recoverable account at December 31, 2002 over a period of three years.

The Fort St. John/Dawson Creek 2004 revenue requirements application, filed in November 2003, sought BCUC approval to increase the gas delivery charge component of rates and to decrease the gas commodity charges. The BCUC approved interim rates effective January 1, 2004 applying a 9.65 percent return against a deemed common equity of 36 percent. The interim rates resulted in rate decreases of between 13 and 14 percent for residential and small commercial customers, respectively.

The BCUC conducted a written hearing process in respect of the Fort St. John/Dawson Creek and Tumbler Ridge divisions in early 2004. A decision by the BCUC on the applications is expected in the second quarter of 2004.

Application to BCUC to Recapitalize the Company Under An Income Trust Ownership Structure

On January 30, 2004, the Company filed an application with the BCUC seeking the approvals required pursuant to the Act to transfer the ownership of the Company 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 current shareholders that would exchange their common shares for units and new investors under an initial public offering of PNG Income Trust units. The application was reviewed at a two day public hearing in mid April 2004. A decision may be rendered by the BCUC on this application by the end of the second quarter of 2004. Any transfer of ownership would also require the approval of the shareholders of the Company, court approval, and acceptable market conditions. The Company can give no assurances that the required approvals will be obtained, or that the conversion to an income trust ownership structure will be completed.

Engineering and Operations

In-Line Inspection

The Company 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 (“ILI”) tools and subsequent repair activities that arise from the information gathered.

The Company began implementing ILI programs on its transmission pipeline in 1989. The 2003 ILI activity involved running the inspection tool from Terrace to Kitimat in the ten-inch line, and from Vanderhoof to a point forty kilometers west in the twelve-inch loop pipeline. The results of these inspections were favourable. The Company intends to continue its ILI program in 2004 and into the foreseeable future at an annual level that continues to address the inherent risks in its ongoing operation.

Compressor Control Systems

Installation of a programmable logic controller-based control system at the Smithers compressor station was completed in 2003. The new system offers more reliable and a greater level of operational flexibility, while allowing for remote control and troubleshooting of the compressor unit. A similar system is planned for installation at the Burns Lake compressor station in 2004, at which point all of the Company’s compressor control systems will have been upgraded.

Khyex River Slide

On November 28, 2003, a massive debris slide 55 kilometers east of Prince Rupert ruptured a section of the eight-inch high-pressure transmission pipeline. Service to four thousand customers in Prince Rupert and Port Edward was interrupted. Liquefied natural gas and compressed natural gas were transported to the Prince Rupert area by truck and were used to provide service to selected community facilities until a temporary repair could be completed. Installation of two two-inch and one four-inch temporary lines was completed within eight days of the line break, restoring service to all customers by December 6, 2003. A permanent repair will be completed in

2004, and is included, net of insurance recoveries, in planned capital expenditures for 2004.

Capital Expenditures

Total capital expenditures in 2003 were 9 percent or \$0.6 million lower than those incurred in 2002 and 19 percent below the average level of expenditures for the last five years. However, capital expenditures in 2002 included \$1.7 million for the permanent repair of the Copper River line break, which occurred in mid 2002. Total capital expenditures prior to mid-year 2000 also included higher levels of expenditures on the upgrading and rehabilitation of the transmission pipeline system.

Planned capital spending in 2004 is primarily directed toward distribution mains and services, as well as transmission mainline permanent repairs and replacement, and is forecast to be approximately \$9.6 million. Included in this estimate is a planned rehabilitation expenditure of approximately \$1.8 million for replacement of a dual-line underwater crossing of the Salmon River. The remainder of the planned expenditures will be directed to numerous small projects which will maintain the Company's assets in good working order and provide for minor expansions of its distribution systems to service new customers.

Operating Activities

Operating, maintenance and administrative costs totaled \$18.5 million in 2003, compared to \$19.2 million in 2002. The lower expenses reflect a lower cost of fuel gas as a result of Methanex supplying fuel gas in kind for its deliveries. These reductions were partially offset by other increases including provision for bad debt, compressor maintenance and costs incurred to pursue options to increase shareholder value.

Liquidity and Capital Resources

The Company has a secured bank demand operating and hedge line of credit in the amount of \$25 million that provides funds for general corporate and working capital requirements. The amount available under this facility is subject to borrowing base requirements. 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, 2003, the amount available under the facility was approximately \$7.1 million, none of which had been drawn.

The Company purchases gas for resale to its core market customers, and passes through the commodity cost of gas to those customers without markup. The rates charged to core market customers are based in part on the projected commodity cost of gas. 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.

Long-term debt repayments in 2003 amounted to \$3.9 million.

In August 2003, subsequent to the BCUC's approval of the Company's new long-term transportation contract with Methanex, Dominion Bond Rating Service ("DBRS") confirmed the Company's BB (high) and Pfd-4 (high) ratings and changed the trends from stable to positive. DBRS noted that the Company's access to liquidity and its near-term earnings outlook remained as

obstacles to a ratings upgrade. In November 2003 DBRS raised the rating on the Company's secured debentures to BBB(low) based on: (i) the long-term contract with Methanex; (ii) positive developments in the Company's regulatory framework including the BCUC approval of the rate stabilization adjustment mechanism, which mitigates variances between actual and forecast deliveries; and (iii) the Company's new \$25 million operating line of credit, which provides it with increased liquidity at a lower cost and access to a hedging line to better manage gas price volatility.

Risk Factors

The Company faces the following strategic, financial and operational risks in carrying out its business:

Concentration of Customer Base and Lack of Diversity

In 2003, 73 percent of energy deliveries were made to the Company's four largest industrial customers compared to 74 percent in 2002. Two of these customers, totaling approximately 8 percent of annual deliveries, have firm gas transportation agreements expiring over the next two years. While the Company has signed a memorandum of agreement with one of these customers for a new long-term contract, it is still subject to BCUC approval. In addition, the Company's new contract with Methanex expires in 2009. The Company'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.

The Company's service area is dependent upon industrial customers, many of which are tied to the forest sector, for its economic stability. A prolonged decline in the forest and other related sectors could negatively impact deliveries to all customer classes.

Commodity Price and Supply

Over the last two years, the commodity cost of natural gas has been highly volatile. The average cost of natural gas remains relatively high and was more than 60 percent higher in 2003 than 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 the 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, and/or counterparty failure to perform.

Capital Availability

The Company's investment activities are financed by cash generated from operations and drawings under its operating line together with proceeds from the issue of long-term debt and share capital. A downgrade of the Company's long-term debt could restrict access to capital provided by traditional lenders.

Regulatory Risk

The Company's asset base is subject to regulation (see "Government Regulation, General"). Changes in the regulatory environment may be beyond the Company's control and may impact the viability of the assets, including the Company's ability to sustain or increase its profitability.

As part of the regulatory process, the Company maintains a number of deferral accounts including, without limitation, a gas cost variance account, the rate stabilization adjustment mechanism account and accounts for pipeline repair and rehabilitation.

The gas cost variance account is utilized to record variances in the Company'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.

The Company'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 the Company 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 the Company's accumulated deferral accounts has an impact on the Company'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. Therefore, recovery of debit balance deferral accounts in future periods is a risk.

Facility Risks

The Company carries on business in a geographic area of British Columbia where a large portion of its pipeline transmission system is located in extremely difficult terrain and where outages have, from time to time, been experienced in the past. Depending on circumstances, such outages may result in loss of revenues and/or increased maintenance costs.

Insurance Risks

The Company maintains insurance against exposures to the physical loss of its pipeline, compressor 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 the Company, its deductibles have been increased and, depending on the number and severity of future outages, the financial impact on the Company could be material.

OTHER INFORMATION

At December 31, 2003, the Company had 93 employees.

The Company did not incur any specific expenditures on research and development during 2003. In the ordinary course of its operations, the Company is required to comply with applicable federal and provincial environmental laws. The Company makes expenditures on environmental protection in the operations of its gas pipeline and distribution systems and in the construction of new facilities. These expenditures are recovered from customers in the rates and tolls approved by the BCUC. The Company does not anticipate making any material capital expenditures for environmental compliance during 2004.

Pacific Northern (N.E.) is involved in a dispute with a customer over the payment for gas transported to the customer. The dispute relates to the customer's obligations to supply its own gas for transportation to its facilities, or failing that, to pay for gas delivered to those facilities. Approximately \$2 million has been included in accounts receivable at March 31, 2004 and December 31, 2003 reflecting management's best estimate of the amount ultimately recoverable. It is not possible to assess the outcome of the dispute at this time and the actual amount recovered could be different than this estimate.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following tables set forth certain consolidated financial information regarding the Company:

	<u>2003</u>	<u>2002</u>	<u>2001</u>
Total assets	\$206,414	\$212,506	\$207,113
Long-term debt	90,209	94,603	82,189
Operating revenues	133,727	109,063	138,595
Net income	5,668	4,590	5,715
Earnings per common share:			
- basic	1.49	1.20	1.52
- diluted (2000 restated)	1.46	1.18	1.51
Dividends per share			
- common ⁽¹⁾	3.55	0.00	0.00
- preferred	1.69	1.69	1.69

⁽¹⁾ Includes both the Class A non-voting common shares and the Class B voting common shares which were reclassified as Common Shares effective December 18, 2003.

Consolidated quarterly results (dollar amounts in thousands, except per share data):

2003 – Quarter ending:	March 31	June 30	Sept. 30	Dec. 31
Operating revenues	\$41,683	\$28,571	\$24,025	\$39,448
Net income (loss)	3,693	61	(709)	2,623
Earnings (loss) per common share – basic	1.01	(0.01)	(0.22)	0.71
Earnings (loss) per common share – diluted	0.99	(0.01)	(0.22)	0.69
2002 – Quarter ending:	March 31	June 30	Sept. 30	Dec. 31
Operating revenues	\$36,090	\$23,370	\$16,714	\$32,889
Net income (loss)	3,316	893	(889)	1,270
Earnings (loss) per common share – basic	0.91	0.23	(0.28)	0.34
Earnings (loss) per common share – diluted	0.90	0.22	(0.28)	0.34

On January 23, 2003 the Company paid a special dividend of \$2.75 per share on the Class A Non-Voting Common Shares and Class B Common shares. Dividends on the common shares were reinstated in March, 2003 at \$0.20 per share per quarter. The Company pays a semi-annual dividend of \$0.84375 per preferred share on January 1 and July 1 of each year.

All of the Class A and Class B Common Shares of the Company were reclassified as Common Shares effective December 18, 2003.

MARKET FOR SECURITIES

The Common Shares and the 6 3/4% Cumulative Redeemable Preferred Shares of the Company are listed on the Toronto Stock Exchange.

DIRECTORS AND OFFICERS

The names, municipalities of residence, positions and principal occupations of the directors and officers of the Company are set out in the following tables. Each director was elected at the last annual meeting to serve until the next annual meeting or until his successor is elected or appointed.

DIRECTORS

<u>Name and year first became a director</u>	<u>Principal occupation and residence</u>
Robert F. Chase ^{1,2,4} 1995	President and Chief Executive Officer Lexacal Investment Corp. West Vancouver, British Columbia
Roy G. Dyce 1982	President and Chief Executive Officer Pacific Northern Gas Ltd. Coquitlam, British Columbia
J. Trevor Johnstone ^{1,5} 2003	Managing Director Tricor Pacific Capital, Inc. West Vancouver, British Columbia
Hugh C. Morris ^{1,3} 1986	Chairman Eldorado Gold Corporation Delta, British Columbia
David J. Rowntree ^{2,3} 2003	Managing Director Tricor Pacific Capital, Inc. West Vancouver, British Columbia
Roderick R. Senft ⁴ 2003	Managing Director Tricor Pacific Capital, Inc. West Vancouver, British Columbia
David G. Unruh ^{3,5} 2003	Vice Chairman & Director Westcoast Energy Inc. West Vancouver, British Columbia
Arthur H. Willms ^{2,4,5} 1983	Director Westcoast Energy Inc. Vancouver, British Columbia

¹ Audit Committee

² Human Resources and Compensation Committee

³ Environment, Health and Safety Committee

⁴ Executive Committee

⁵ Corporate Governance Committee

OFFICERS

R.F. Chase

Office and residence

Chairman of the Board
West Vancouver, British Columbia

R.G. Dyce

President and Chief Executive Officer
Coquitlam, British Columbia

E.A. Fletcher

Chief Financial Officer (on maternity leave)
Surrey, British Columbia

K. R. Teitge

Interim Chief Financial Officer
North Vancouver, British Columbia

G.B. Weeres

Vice President, Operations and Engineering,
Delta, British Columbia

C.P. Donohue

Director, Regulatory Affairs & Gas Supply
and Assistant Secretary
North Vancouver, British Columbia

K.E. Stark-Anderson

Secretary
Vancouver, British Columbia

During the last five years, all of the directors and officers have been employed in various capacities by the Company or by the companies indicated opposite their names except: Ms. E.A. Fletcher was Manager, Finance & Administration with Star Shipping (Canada) Ltd. prior to January 1998 until March 2000; Mr. K.R. Teitge was an independent consultant from June 2003 through January 2004 and was Director, Corporate and Project Finance, Westcoast Energy Inc. prior to January 1998 until June 2003; Ms. K.E. Stark-Anderson is Senior Solicitor and Corporate Secretary of Westcoast Energy Inc.

ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities, options to purchase securities and interests of insiders in material transactions, is contained in the Management Proxy Circular dated March 15, 2004 for the Company's 2004 Annual and Special Meeting of Shareholders. Additional financial information is provided in the Company's consolidated financial statements for the year ended December 31, 2003. Management's Discussion and Analysis, which appears on pages 12 to 28, inclusive, of the Company's 2003 Annual Report, is incorporated by reference into and forms an integral part of this annual information form. Copies of these documents may be obtained upon request from the Secretary, Pacific Northern Gas Ltd., 950 -1185 West Georgia Street, Vancouver, British Columbia, V6E 4E6.