



PACIFIC NORTHERN GAS ANNUAL REPORT 2006

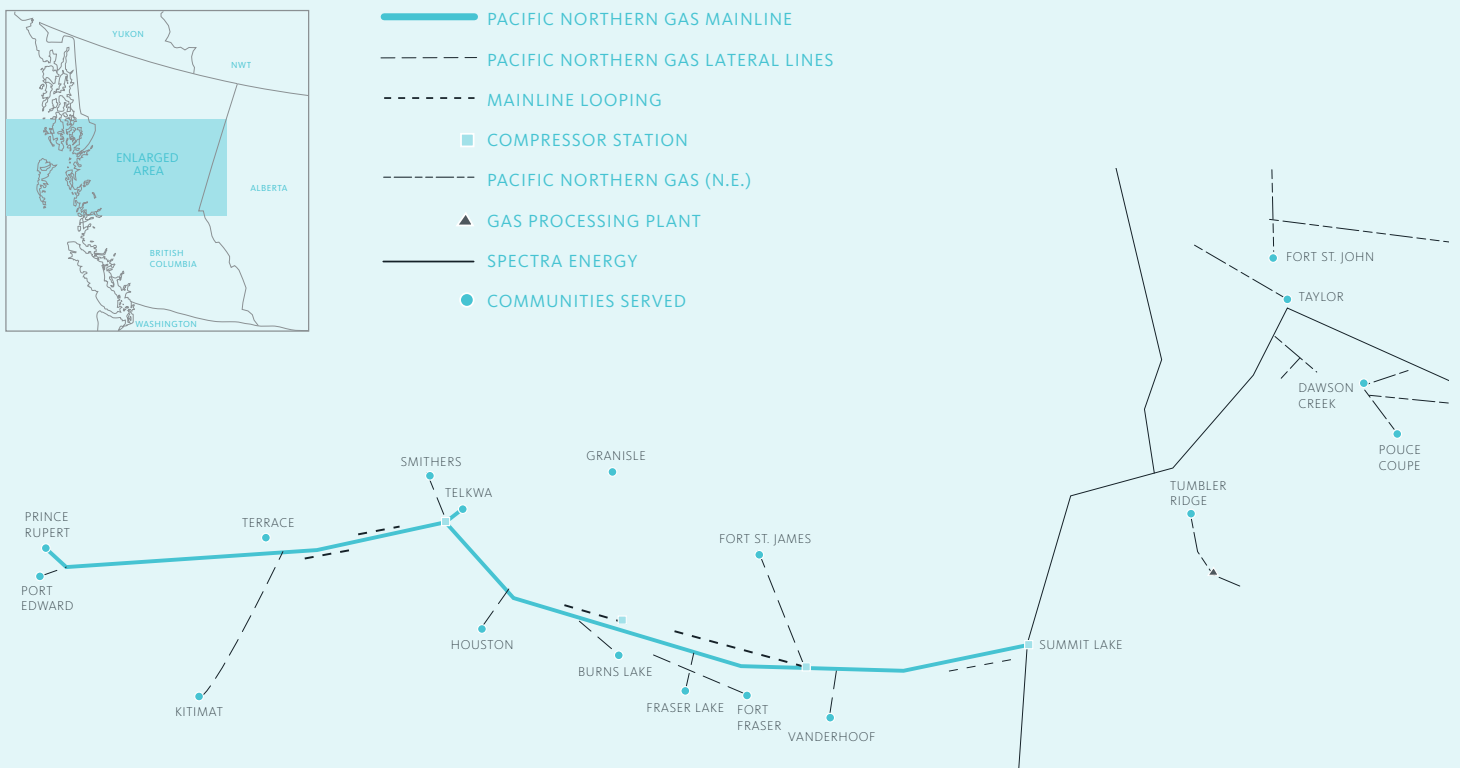
PACIFIC NORTHERN GAS

PACIFIC NORTHERN GAS LTD. DELIVERS NATURAL GAS TO CUSTOMERS IN WEST-CENTRAL BRITISH COLUMBIA, AND THROUGH ITS SUBSIDIARY, PACIFIC NORTHERN GAS (N.E.) LTD., TO CUSTOMERS IN THE PROVINCE'S NORTHEAST.

Pacific Northern's transmission pipeline is connected to the Spectra Energy (formerly Duke Energy) system near Summit Lake, British Columbia and extends 587 kilometers to the west coast. Service is provided to some 23 thousand customers including a number of industrial operations. In addition, propane vapour distribution is provided in the community of Granisle.

Pacific Northern Gas (N.E.) systems serve some 16 thousand customers in the Fort St. John, Dawson Creek, and Tumbler Ridge areas. Gas supply is received at a number of locations within the Fort St. John service area. In the Dawson Creek area the Company's transmission pipeline is used to transport gas from the Spectra Energy system. In Tumbler Ridge the Company operates its own gas processing plant.

Pacific Northern's head office is located in Vancouver, British Columbia. Customer care and administrative functions are supported from a regional centre in Terrace. In addition, personnel responsible for customer service and system construction, operation and maintenance are stationed in nine communities located within the Company's service area.



COMPARATIVE FINANCIAL HIGHLIGHTS

YEARS ENDED DECEMBER 31	2006	2005	2004	2003	2002
Total energy delivered (TJ)	12 395	32 844	38 971	36 638	39 463
Income statement (\$ in thousands)					
Net income	4,951	6,660	5,408	5,668	4,590
Cash flow statement (\$ in thousands)					
Operating cash flow	10,403	15,696	14,634	14,153	14,570
Additions to plant, property and equipment	8,093	6,753	11,276	5,406	5,965
Increase in deferred charges	269	1,799	1,071	2,519	372
Balance sheet (\$ in thousands)					
Total investment in utility plant	172,996	171,351	176,780	174,348	177,314
Total assets	230,065	215,210	207,657	206,414	212,506
Long term debt	71,679	76,560	81,440	85,827	90,224
Common shareholders' equity	79,777	77,692	73,950	71,522	68,966
Common share statistics					
Earnings per common share – Basic	\$ 1.27	\$ 1.75	\$ 1.41	\$ 1.49	\$ 1.20
Earnings per common share – Diluted	\$ 1.26	\$ 1.72	\$ 1.38	\$ 1.46	\$ 1.18
Dividends declared per common share	\$ 0.80	\$ 0.80	\$ 0.80	\$ 0.80	\$ 2.75
Dividends declared per preferred share	\$ 1.69	\$ 1.69	\$ 1.69	\$ 1.69	\$ 1.69
Common shares outstanding (thousands)					
Average for the year	3,631	3,620	3,597	3,583	3,553
End of year	3,641	3,626	3,604	3,584	3,579

EARNINGS PER SHARE



REPORT TO SHAREHOLDERS

2006 has been an encouraging year for Pacific Northern Gas. Outstanding issues such as resolving the regulatory uncertainty around Methanex's terminated contract, and whether it was in our interest to convert to an income trust, have been answered. We can now focus our energy on what we believe is the big, long-term opportunity for both our customers and shareholders – the Kitimat to Summit Lake ("KSL") Project – while maintaining a high standard of performance in our existing operations and service areas.

FINANCIAL REVIEW

Net income for 2006 was \$5.0 million, or \$1.27 per share. The Company's share of pipeline expansion development expenditures for the KSL Project, net of income taxes, amounted to \$1.7 million, or \$0.46 per share. Net income in 2006 would have remained relatively unchanged from 2005 if we had not incurred any KSL Project development costs.

MARKET ENVIRONMENT

Gas prices in the B.C. market place were again quite volatile in 2006, with high prices reaching nearly \$10.00 per gigajoule early in the year but then falling to less than \$4.00 over the summer and autumn seasons. January 2007 monthly gas prices were 35 percent lower than prices the previous year. To reduce volatility of customer rates in the long term, we have refined our hedging program to be able to fix prices for gas nearly two years in advance, currently through to October 2008.

PIPELINE OPERATIONS

We are proud to say that our pipeline systems operated reliably and safely throughout the year. In accordance with the Company's overall pipeline integrity management plan, several improvements were made to the pipeline located between Terrace and Prince Rupert in order to ensure safe and reliable service to these remote locations.

RESOLUTION

The British Columbia Utilities Commission issued a decision in mid-August 2006 approving the Company's application to recover the reduction in revenue that resulted from the closure of the Methanex facility at Kitimat from our other customers. The Commission's duty to set rates that allow utilities the opportunity to recover prudent and reasonable service costs was discussed at length during the decision-making process. The Commission

recognized that we had taken all prudent steps to manage and reduce our costs.

With this decision, in addition to the previous Commission approval to convert to an income trust, the Company was in a strong position to proceed with the income trust conversion.

However, at the end of October 2006, the Federal Minister of Finance announced new taxation rules for income trusts, which were effective immediately for those companies that had not yet converted. Given these recent changes to the Canadian taxation regime, we do not expect to convert to an income trust, even in light of the Commission's supportive decisions.



ROBERT F. CHASE
Chair of the Board

THE KSL OPPORTUNITY

In 2006, we continued to pursue the development project that would require the looping of the mainline transmission system from Kitimat to Summit Lake. This expansion, referred to as the KSL Project, would provide gas transportation services to Kitimat LNG Inc.'s proposed liquefied natural gas ("LNG") import, regasification and send-out terminal to be located on the Douglas Channel, south of Kitimat. On July 17, 2006 we announced the formation of Pacific Trail Pipelines Limited Partnership ("PTP"), created for the purpose of developing the KSL Project. PTP is a 50/50 partnership between the Company and Galveston LNG Inc., the parent company of Kitimat LNG Inc. Under the partnership agreement, the Company and Galveston agreed to share all project development costs equally, and the Company also agreed to take responsibility for obtaining all required permits for construction of the pipeline.

I am pleased to report that we've made significant progress on environmental studies, pipeline routing, First Nations consultation and preliminary engineering work of the KSL Project. We expect to file an application in the second quarter of 2007 with the intention of PTP receiving the KSL Project approval certificate from the British Columbia Environmental Assessment Office ("BCEAO") in early 2008. We have been actively engaged in the approval process with the BCEAO since late 2005.

A key component of the BCEAO process is consultation with and accommodation of First Nations interests, as the KSL Project traverses the claimed traditional territory of 17 First Nations. We are meeting with First Nations representatives to ensure the interests of all affected First Nations are accommodated. Open houses were also conducted along the entire route of the KSL Project pipeline during 2006, with strong community support shown at every public meeting.

If the KSL Project proceeds, the anticipated key benefits include:

- Lower rates to existing customers based on economies of scale and higher utilization of the pipeline system;
- A long term secure supply of gas at competitive prices to support additional industrial development in the northwest corridor of B.C.;
- Advancement of the long term relationship between the Company and First Nations; and
- Improved returns to shareholders.

In 2007, our planned share of KSL Project expenditures via PTP is estimated at \$2.3 million for the environmental permit application process, including costs associated with First Nations consultations and preliminary engineering. Until the project attains some commercial certainty, the project development expenditures will continue to be expensed.

In 2007, we plan to issue new long term debt to fund the capital program as well as pipeline expansion development expenditures. We last issued long term debt in late 2002, which has since been drawn down by \$18 million without any corresponding decline in long term assets.


PTP expects to commence construction of the KSL Project facilities by the fourth quarter of 2008. Construction is subject to a number of conditions including the securing of LNG supply by Kitimat LNG Inc., financing and regulatory approvals.

Looking forward, in 2007 we expect to complete the work required in order to obtain all of the necessary BCEAO environmental approvals for the KSL Project. Once commercial certainty of the project is attained, further regulatory approvals will be sought in 2008.

IN CLOSING

I would like to thank the Company's Board of Directors for their valuable support throughout the year, especially with respect to advancing the KSL Project. I also commend all employees for their strong efforts and continuing commitment to provide high quality service while working safely.

ROY G. DYCE
President and Chief Executive Officer



ROY G. DYCE
President and
Chief Executive Officer

DATE: FEBRUARY 19, 2007

This discussion should be read in conjunction with the enclosed audited consolidated financial statements of Pacific Northern Gas Ltd. (the "Company") for the year ended December 31, 2006. These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All amounts are stated in Canadian dollars unless otherwise indicated.

FORWARD-LOOKING STATEMENTS

Management's discussion and analysis contains certain forward-looking statements that are subject to risks and uncertainties that may cause the results or events predicted in this discussion to differ materially from actual results or events. In addition to the risks outlined in the Risk Management section at the end of the discussion and in the Company's 2006 Annual Information Form under the heading "Risk Factors," factors which could cause the results or events to differ include, but are not limited to: general economic conditions and markets; gas supply availability; gas commodity price volatility; competition; decisions by regulators; seasonal weather patterns; financing of investments as well as the value of such investments; the cost and availability of capital; and the ability of the Company to attract and retain quality employees. No assurance can be given that results, performance or achievement expressed in, or implied by, forward-looking statements within this disclosure will occur, or if they do, that any benefits may be derived from them. The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

BUSINESS OVERVIEW AND OUTLOOK

Pacific Northern Gas Ltd. and its wholly-owned subsidiary Pacific Northern Gas (N.E.) Ltd. are natural gas distribution utilities operating within the Province of British Columbia, Canada.

The Company operates in two service areas, a transmission and distribution system in the west-central portion of northern British Columbia ("Western system") and a distribution system in northeastern British Columbia ("Northeast system"). The Northeast system is comprised of two divisions, the Fort St. John/Dawson Creek division and the Tumbler Ridge division.

The Company continues to monitor the competitiveness of its natural gas retail rates relative to alternative heating sources in its service area. Substantial increases in gas supply commodity prices over the last few years, combined with increases in the Company's delivery margins for residential, commercial and small industrial customers for its Western system, have led to retail gas rates which are similar to, or higher in the case of residential customers, than comparable electricity rates.

On August 30, 2005, Methanex Corporation ("Methanex") gave notice of termination of its transportation service agreement with the Company and on February 28, 2006, Methanex paid approximately \$23.3 million to terminate the agreement. The termination payment was recorded as an interest bearing credit deferral, and will be amortized into income over the period from March 1, 2006 to October 31, 2009. The Company sought and obtained Commission approval in its 2006 revenue requirements application to recover the estimated \$4.8 million Methanex margin reduction in 2006, net of the termination payment amortization in 2006, from its remaining customers. Depending on customer growth, it may be necessary to seek further rate increases commencing in 2010 after the Methanex termination payment has been fully amortized in rates.

The Company's strategic focus in 2007 will be to continue to pursue a potential expansion of the transmission pipeline system to meet the requirements of a proposed LNG regasification facility near Kitimat in order to enhance shareholder value.

In 2005, the Company commenced preliminary study and investigation of a project to loop its mainline transmission system from Kitimat to Summit Lake (the "KSL Project"). The KSL Project would provide gas transportation services for up to 1.0 billion cubic feet per day from the proposed Kitimat LNG Inc. liquefied natural gas ("LNG") receiving and regasification terminal (the "Terminal"), to be located on Douglas Channel approximately 15 kilometers southwest of Kitimat, to the Company's existing inter-connection with the Spectra Energy ("Spectra Energy") transmission system. The KSL Project would entail the construction of approximately 470 kilometers of a 30 or a 36 inch diameter pipeline and associated compression facilities, at an estimated cost of \$900 million to \$1.2 billion. In 2006, Kitimat LNG Inc., a private company based in Calgary, Alberta, received a Project Approval Certificate from the British Columbia Environmental Assessment Office as well as approval from the Canadian Environmental Assessment Agency for the construction and operation of the Terminal.

On July 17, 2006, the Company announced the formation of Pacific Trail Pipelines Limited Partnership ("PTP"), a 50/50 partnership between the Company and Galveston LNG Inc., the parent company of Kitimat LNG Inc., for the purpose of developing the KSL Project. In addition, PTP and Kitimat LNG executed a Precedent Agreement to coordinate the process of obtaining authorizations for the KSL Project with the development of the Terminal. The agreement outlines, among other things, the key economic arrangements between PTP and Kitimat LNG, as well as the targeted timeline and key milestones for construction of the KSL Project and the Terminal.

The route for the KSL Project is being determined through technical field studies and consultation with First Nations, the public and regulatory authorities. The Company's existing right-of-way will be used where appropriate. Upon completion of the KSL Project, and subject to regulatory and shareholder approvals, the Company's existing mainline transmission system will be transferred to PTP and integrated with the KSL Project facilities. The Company will continue to own and operate its existing gas distribution systems, including its Customer Care Centre in Terrace. The Company's share of planned development expenditures for the KSL Project in 2007 is expected to be approximately \$2.3 million, of which \$0.7 million is expected to be incurred in the first quarter of 2007. The Company's share of further KSL Project development expenditures will continue to be expensed until suitable commercial arrangements for firm gas transportation services by PTP are in place. If anticipated development expenditures for 2007 are expensed, earnings will be reduced by an estimated \$1.5 million (\$0.41 per share), of which \$0.5 million (\$0.12 per share) is expected to occur in the first quarter of 2007.

PTP expects to commence construction of the KSL Project facilities by the fourth quarter 2008. Commencement of construction is subject to a number of conditions including the securing of LNG supply by Kitimat LNG Inc., financing of the Terminal and KSL Project and regulatory approvals for the KSL Project. The regulatory requirements for the KSL Project include a Project Approval Certificate to be obtained through the Province of British Columbia's environmental assessment process, approvals under the Canadian Environmental Assessment Act, a Certificate of Public Convenience and Necessity from the Commission and other permits required from the B.C. Oil and Gas Commission. The Company can give no assurances that the regulatory approvals will be obtained or that construction of the KSL Project by PTP will proceed.

By decision dated September 9, 2005 and modified on October 28, 2005, the British Columbia Utilities Commission (the "Commission") granted conditional approval of the Company's December 2004 application to recapitalize under an income trust ownership structure. On October 31, 2006, the Federal Minister of Finance announced new rules for the taxation of income trusts, effective immediately for companies who convert to an income trust structure after October 31, 2006. As a result, the Company does not expect to convert to an income trust.

OVERALL PERFORMANCE

Net income for 2006 was \$5.0 million, compared with \$6.7 million for 2005. After providing for preferred share dividends, earnings per common share for 2006 were \$1.27 compared with \$1.75 for 2005. Included in net income for the year are charges, net of income taxes, of \$1.7 million, or \$0.46 per share, relating to the Company share of KSL Project expenditures.

SELECTED ANNUAL INFORMATION

The following financial information has been prepared in accordance with Canadian GAAP and is shown in Canadian dollars.

	2006	2005	2004
(\$ in thousands, except per share and per GJ figures)			
Deliveries (TJ) –			
Sales – Western system	3 466	3 686	3 902
Sales – Northeast system	3 539	3 302	3 436
Transportation service –			
Western system	3 516	24 018	29 803
Northeast system	1 874	1 838	1 830
Total	12 395	32 844	38 971
Customers at period end	39,511	39,295	39,291
Weighted average cost of gas purchased (\$ per GJ)	7.91	8.31	6.42
Operating revenues	138,848	159,950	137,755
Operating margin, consisting of operating revenues less cost of sales	47,730	48,663	48,801
Net income	4,951	6,660	5,408
Basic earnings per common share	1.27	1.75	1.41
Diluted earnings per common share	1.26	1.72	1.38
Total assets	230,065	215,210	207,657
Total long term financial liabilities	95,682	92,214	97,277
Dividends paid per common share	0.80	0.80	0.80
Dividends paid per preferred share	1.69	1.69	1.69

RESULTS OF OPERATIONS

Deliveries to residential and commercial customers in 2006 were higher by 0.1 petajoules, or 1 percent, compared to deliveries in 2005. Increased deliveries to the commercial sector more than offset lower deliveries in the residential sector. Weather in 2006 was approximately 4 percent colder than in 2005, accounting for a portion of the increased deliveries to the commercial sector; however, residential usage declined due to a small net loss of residential customers as well as strong conservation efforts that the Company believes are due, in part, to higher delivered gas prices for its Western system. Deliveries to residential and small commercial customers in 2006 were lower by 0.5 petajoules, or 8.5 percent, compared to the forecast volumes used to set customer rates for 2006. This reduction in deliveries compared to forecast 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 \$1.3 million (\$0.9 million in 2005), arising from differences between actual and forecast volumes for residential and small commercial customers.

Operating revenues in 2006 decreased to \$138.8 million as compared with \$160.0 million in 2005, largely due to the decrease of \$23.4 million in sales of gas surplus to the needs of the Company's sales customers ("off system gas sales"). A 29 percent reduction in off system gas sales resulted from the Company more closely aligning gas purchases with customer demand in the summer of 2006. Natural gas commodity prices, which are passed through to 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, excluding off system gas sales, were higher by \$2.3 million in 2006 due to the higher commodity cost of gas as compared to 2005. In addition, operating revenues from transportation services were lower by \$9.7 million in 2006, due primarily to the closure of Methanex Corporation's ("Methanex") Kitimat facility in the fourth quarter of 2005. Included in other operating revenues in 2006 is \$5.6 million of amortization of the Methanex termination payment, received February 28, 2006.

Operating margin in 2006 decreased to \$47.7 million, as compared with \$48.7 million in 2005. This decrease was due to anticipated reductions in expenses in 2006 that were used to determine customer rates.

NATURAL GAS DELIVERIES

Natural gas deliveries in 2006 totaled 12 395 terajoules* compared with 32 844 terajoules in 2005. A comparison of deliveries for the years 2006, 2005 and 2004 is provided in the following table:

Deliveries in terajoules	2006	2005	2004
Sales:			
Residential	3 066	3 135	3 279
Commercial	2 706	2 659	2 655
Small Industrial	710	689	778
Large Industrial	523	506	626
Total Sales	7 005	6 989	7 338
Transportation Service:			
Commercial	157	61	60
Small Industrial	2 774	2 887	2 958
Large Industrial – Methanex	3	20 497	25 952
Large Industrial – Other	2 456	2 410	2 663
Total Transportation Service	5 390	25 855	31 633
Total Deliveries	12 395	32 844	38 971

*The joule is a metric energy measurement unit. One gigajoule (GJ) is equivalent to 0.94782 British thermal units (BTU). One terajoule (TJ) equals one thousand GJ. One petajoule (PJ) equals one million GJ. In volumetric units, 1000 cubic meters is equivalent to 35,301 thousand cubic feet.

Transportation deliveries to large industrial customers decreased 87 percent from 2005 to 2006, primarily as a result of Methanex permanently shutting down its methanol/ammonia complex in Kitimat in November 2005. Deliveries to large industrial customers other than Methanex increased by 2 percent in 2006 compared to 2005.

Deliveries to residential customers decreased in 2006 by approximately 2.2 percent from 2005 levels notwithstanding that the weather was approximately 4 percent colder in 2006 compared to 2005. Deliveries to commercial customers increased in 2006 by approximately 5.2 percent from 2005 levels. Commercial transportation service deliveries increased significantly from 2005 to 2006 primarily due to several commercial sales customers converting to transportation service during 2006. Given these were conversions by existing sales customers, the increase in commercial transportation service deliveries resulted in a decrease in total operating revenues; however, operating margin was relatively unaffected by the conversions. Gas deliveries to the commercial transportation service sector are forecast to increase in 2007 as many of the conversions occurred in the last two months of 2006. Fewer conversions are expected in 2007 compared to 2006 as the gas marketers carried out their main marketing campaigns in the Company's service areas in 2006.

CUSTOMER ADDITIONS

In 2006, 367 new services were connected to the Company's distribution systems, compared with 420 in 2005. Most of the service additions resulted from continued strong economic activity in the Northeast system. The Company experienced a net increase of only 216 customers as a result of 151 customers leaving the distribution system, primarily in the Company's Western system service area which continues to experience generally poor economic conditions.

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 system service area.

NATURAL GAS SUPPLY

All of the Company's residential customers, most of its commercial customers and a number of its small industrial customers purchase gas from the Company at rates which include the gas commodity cost and the Company's cost of delivering gas to the customers' premises. The gas commodity cost paid by the Company to its gas suppliers is passed through without mark-up to customers.

The Commission 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 actually paid by the Company from the gas cost recovery charge 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 under a gas price management plan that is filed with the Commission on an annual basis.

A gas supply contracting plan is also prepared annually and filed with the Commission for review prior to finalizing annual gas purchase arrangements. The gas contracting plan is designed to ensure the Company has adequate gas supplies to meet the requirements of its customers on the coldest day of the year, normally referred to as "the peak day." Contracted gas that is surplus to customer requirements is sold into other markets at prevailing market prices through off system gas sales. Most of the Company's contracted gas supply is produced in British Columbia.

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

For 2006, approximately 34 percent of gas purchases were hedged pursuant to the Company's gas price management plan (for further information as of December 31, 2006 with regard to 2006 gas supply, see Financial Instruments and Other Instruments below).

Most of the Company's gas supply is comprised of the pooled gas stream available from the Spectra Energy transmission pipeline system. This includes all of the supply to the Company's transmission line serving its Western system service area and approximately 73 percent of the supply for the Fort St. John and Dawson Creek service areas.

In addition to the supply from the Spectra Energy system, the Fort St. John system incorporates two interconnections with Canadian Natural Resources Limited's West Stoddart Pipeline, providing 36 percent of the Fort St. John system's requirements. In Dawson Creek, approximately 10 percent of the required supply is received from a local producer of sweet (pipeline quality) gas at a point where its 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 Canadian Natural Resources and the Company operates its own gas processing facilities.

In 2006, gas was purchased under a number of short term seasonal, base load and spot gas supply arrangements. Short term gas supply contracts are in keeping with current industry practices.

LARGE INDUSTRIAL CUSTOMERS

The Company has firm transportation service and interruptible sales/service agreements with two of its large industrial customers: West Fraser and Alcan Smelters and Chemicals Ltd. ("Alcan"). The transportation service and sales contracts with West Fraser and Alcan are in effect through December 31, 2013 and October 31, 2008, respectively. The agreement with Alcan will continue to be in effect beyond October 31, 2008 unless Alcan or the Company gives notice of termination. During 2006, deliveries to West Fraser and Alcan accounted for 15.9 and 7.9 percent, respectively, of the Company's total gas deliveries and 1.5 and 4.2 percent, respectively, of operating revenues.

West Fraser and Alcan 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 operation during sustained periods of low commodity prices.

Deliveries to Methanex in 2005 accounted for approximately 62 percent of volumes delivered by the Company and approximately 76 percent of the Company's operating revenues. Margin recovery in 2006 from Methanex was approximately \$10.4 million lower than in 2005 due to the Methanex contract termination in February 2006. This reduction was partially offset by credit amortization of \$5.6 million of the contract termination payment in 2006 resulting in a net margin reduction of \$4.8 million. The Company sought and obtained Commission approval in its 2006 revenue requirements application to recover the net \$4.8 million margin reduction from its remaining customers.

The Company delivers gas to its other large industrial customer, British Columbia Hydro and Power Authority ("BC Hydro"), under an interruptible sales/service agreement for emergency electric power generation at BC Hydro's facility in Prince Rupert.

REGULATORY ACTIVITIES

The Company is subject to regulation under the Utilities Commission Act of British Columbia. The Commission regulates the business of the Company, including the construction and operation of major facilities, the issuance of securities, the determination of rates for the sale and transportation of gas, and the terms and conditions of service.

In approving rates, the Commission must determine that the rates reflect a fair and reasonable charge for the nature and quality of service provided to customers. The rates should be sufficient to enable the Company to earn a fair and reasonable compensation for its services and a fair and reasonable return upon the value of its property.

The Commission determines customer rates using a fixed rate approach on the basis of forecasts of both the cost of service and the volumes of gas delivered through the transmission and distribution systems. The cost of service consists of the cost of transporting all gas delivered, including operating, maintenance and administrative expenses, depreciation of facilities, income and other taxes and a return on rate base. Rate base is the sum of the depreciated cost of property, plant and equipment that is used or useful in serving the Company's customers, plus a reasonable allowance for working capital. The Commission 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 Commission, generally on an annual basis. The Commission may consider these applications through a public hearing process (either oral or written), or through Commission staff supervised negotiations between the Company and its customers under negotiated settlement guidelines issued by the Commission. Settlements are subject to final approval by the Commission.

In November 2005, the Company filed revenue requirements applications with the Commission for approval of new rates to take effect January 1, 2006 for all service areas. The revenue requirement applications for 2006 were considered by the Commission through a negotiated settlement and written hearing process for the Western system and a negotiated settlement process for the Fort St. John/Dawson Creek and Tumbler Ridge divisions.

The Commission issued its decision on the 2006 revenue requirements application on August 16, 2006 for the Western system. The 2006 allowed rate of return on common equity was 9.45 percent reflecting a 65 basis point premium over the low risk benchmark utility rate of return and based on a deemed common equity component of rate base of 40 percent.

On August 16, 2006, the Commission approved the settlement agreement reached between the Company and its customers respecting the Company's 2006 revenue requirements application for the Northeast system. The 2006 allowed rate of return on common equity was 9.20 percent for the Fort St. John/Dawson Creek division and 9.45 percent for the Tumbler Ridge division, based on a deemed common equity component of rate base of 36 percent in respect of both divisions. The allowed rates of return on common equity include premiums of 40 and 65 basis points over the low risk benchmark utility rate of return for the Fort St. John/Dawson Creek and Tumbler Ridge divisions, respectively.

WESTERN SYSTEM

For 2006, the Commission continued its direction to defer the difference between actual operating margin from deliveries to Methanex, West Fraser, Alcan and B.C. Hydro and the forecast operating margin used by the Company in its revenue requirement application in an Industrial Customers Deliveries Deferral Account ("ICDDA"). The ICDDA did not impact 2006 net earnings as actual 2006 deliveries to these customers were approximately the same as forecast deliveries used for determining rates. The Commission also accepted the Company's forecast of gas supply costs for 2006. Rate riders were approved in various amounts for 2006 to refund a credit balance accumulated in the gas cost purchase variance payable account. In 2006, the reduction in customer revenue from credit rate riders totalled \$2.1 million, and was applied, on an after tax basis, to reduce the gas cost purchase variance payable account.

In the 2006 revenue requirements application, the Company identified plant, property and equipment assets which would not be required on an ongoing basis to provide service to its customers, having regard to the closure of the Methanex plant in late 2005. The Company received Commission approval to remove from rate base compressor facilities, pipeline loops and various other fixed assets with a net book value of \$5.05 million and transfer them to a non-rate base, interest bearing deferral account effective December 31, 2005. The deferral account will be amortized on a straight-line basis over ten years commencing in 2006.

The 2007 revenue requirements application for the Western system was filed with the Commission in October 2006. The application sought approval of an increase in delivery charges of 1.7 percent. The Commission approved interim gas delivery charge increases effective January 1, 2007 at the level set forth in the application. The Commission established a written hearing process in January 2007 with final written argument to be filed by the Company on March 29, 2007.

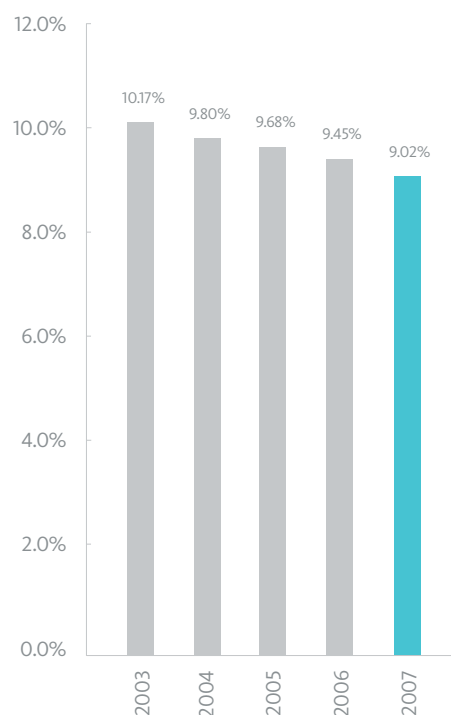
The gas supply commodity charge component of rates did not change as of January 1, 2007 compared to the rates effective October 1, 2006. The Commission reviews the gas supply commodity charges on a quarterly basis. The next potential change to the gas supply charge in rates will be April 1, 2007.

The forecast 2007 residential and commercial deliveries contained in the 2007 revenue requirements application for the Western system are approximately 71 percent higher than actual gas deliveries to these

customer classes in 2006. Deliveries to small industrial customers are projected to be approximately 8.1 percent lower in 2007 compared to actual gas deliveries in 2006. The decrease is primarily due to one sawmill closing in mid 2006 and another sawmill planning to install a new energy system in 2007 that does not use natural gas.

Prior to the commencement of each calendar year, the Commission resets the allowed rate of return on common equity for each of the Company's regulatory divisions by a formula which uses, among other things, a consensus forecast of yields on 10-year Government of Canada bonds for the forthcoming year. Largely as a result of the lower 10-year bond yields which were in effect in the latter part of 2006 relative to the same period in 2005, the consensus forecast of 2007 10-year bond yields declined relative to the late 2005 consensus forecast of 10-year bond yields for 2006. Through application of the formula the approved rates of return on common equity for the Company have declined. In November 2006, the Commission confirmed that the formula resulted in an 8.37 percent rate of return for a low risk benchmark utility in 2007. For the Company, a return on equity risk premium of 65 basis points relative to the low risk benchmark utility return applies to the Western system resulting in an allowable rate of return on common equity of 9.02 percent for 2007.

WESTERN SYSTEM ALLOWED RETURN ON COMMON EQUITY 2003-2007



FORT ST. JOHN / DAWSON CREEK DIVISION

The Commission accepted the Company's forecast of gas supply costs for 2006. Rate riders were approved in 2006 on a quarterly basis to recover/refund debit/credit balances in the gas cost purchase variance account. In 2006, customer recoveries/refunds from rate riders totalled a net recovery of \$61,000, which was applied, on an after tax basis, to the gas cost purchase variance account.

The Fort St. John/Dawson Creek 2007 revenue requirements application, filed in October 2006, sought Commission approval to increase the gas delivery charge component of its gas rates. The Commission approved interim delivery charges effective January 1, 2007 at the level set forth in the application which are higher by approximately 0.7 percent for both residential and small commercial customer classes compared to rates in effect as of December 31, 2006.

The rate increase would have been somewhat higher but for the implementation of a depreciation adjustment credit deferral account in 2006. As a result of a detailed analysis of property, plant and equipment cost and retirement records conducted in 2006, various assets were identified as retired or disposed of in prior years with no retirement being recorded. The Company has reversed this accumulated depreciation, and transferred the balance to a depreciation adjustment credit deferral account. The Company has proposed amortizing the depreciation credit in rates over the 2007/2008 two year period.

The forecast 2007 residential and commercial deliveries contained in the 2007 revenue requirements application for the Fort St. John/Dawson Creek system are approximately 79 percent higher than actual gas deliveries to these customer classes in 2006. Deliveries to small industrial customers are projected to be approximately 0.1 percent lower in 2007 compared to actual gas deliveries in 2006.

The gas supply commodity charge component of rates did not change as of January 1, 2007 compared to the rates effective October 1, 2006. The Commission reviews the gas supply commodity charges on a quarterly basis. The next potential gas supply charge rate changes will be determined as of April 1, 2007. A return on equity risk premium of 40 basis points relative to the low risk benchmark utility return applies to the Fort St. John/Dawson Creek division resulting in an allowable rate of return on common equity of 8.77 percent for 2007.

TUMBLER RIDGE DIVISION

The Tumbler Ridge 2007 revenue requirements application was filed with the Commission in October 2006. The application seeks Commission approval to decrease the gas delivery charge component of rates effective January 1, 2007. The requested decreases in the gas delivery charge component are primarily due to higher credit amortization (see above explanation under Fort St. John/Dawson Creek division of depreciation adjustment credit) and associated lower income tax expense. In addition, gas deliveries are forecast to be higher in 2007, primarily due to Canadian Natural Resources adding a new compressor to their gas well production facilities. The Commission approved interim delivery charges effective January 1, 2007 at the level set forth in the application which are approximately 12.4 percent lower for residential and small commercial customers relative to rates in effect on December 31, 2006.

The gas supply commodity charge component of rates did not change as of January 1, 2007 compared to the rates effective October 1, 2006. However, a commodity credit rate rider of \$0.427/GJ was implemented effective January 1, 2007 to reduce the gas cost purchase variance payable account. A return on equity risk premium of 65 basis points relative to the low risk benchmark utility return applies to the Tumbler Ridge division resulting in an allowable rate of return on common equity of 9.02 percent for 2007.

A written hearing process for the Fort St. John/Dawson Creek and Tumbler Ridge divisions' 2007 revenue requirements applications was established by the Commission in January of 2007 with final written argument to be filed by the Company on March 29, 2007.

SUMMARY OF QUARTERLY RESULTS

The following financial information has been prepared in accordance with Canadian GAAP and is shown in Canadian dollars.

	2006			
	MAR. 31	JUNE 30	SEPT. 30	DEC. 31
(\$ in thousands, except for per share data)				
Operating revenues	56,605	20,203	15,850	46,190
Net income (loss)	4,920	(837)	(1,451)	2,319
Earnings (loss) per common share – basic	1.33	(0.25)	(0.42)	0.61
Earnings (loss) per common share – diluted	1.31	(0.25)	(0.42)	0.60
	2005			
	MAR. 31	JUNE 30	SEPT. 30	DEC. 31
Operating revenues	47,798	30,293	32,238	49,621
Net income (loss)	3,984	137	(772)	3,311
Earnings (loss) per common share – basic	1.08	0.02	(0.24)	0.89
Earnings (loss) per common share – diluted	1.06	0.01	(0.24)	0.88

The Company's natural gas distribution business is very seasonal, with higher sales in the colder winter months and lower sales in warmer months as a result of a substantial portion of its gas sales being used for space heating purposes. As a result, the Company earns the majority of its net income in the first and fourth quarters of its fiscal year and often realizes losses in the other quarters. With the termination of the Methanex contract in 2006, deliveries to residential and commercial customers make up a higher proportion of total deliveries compared to 2005. Deliveries to residential and commercial customers are significantly more temperature sensitive than deliveries to industrial customers. As a result, the Company's net income in the first quarter of 2006 was increased by \$0.8 million compared to the same period in 2005, and similarly, net income in each of the second and third quarters of 2006 was reduced by approximately \$0.4 million compared to the same periods in 2005. In addition, net income in the second, third and fourth quarters of 2006 was reduced by \$0.5 million, \$0.6 million and \$0.6 million, respectively, due to the expensing of KSL Project development expenditures.

LIQUIDITY

Cash and short term investments at December 31, 2006 are \$11.6 million higher than at December 31, 2005 due to receipt of the Methanex termination payment in February 2006, which was partially used to repay outstanding bank indebtedness. Accounts receivable at December 31, 2006 are \$1.1 million higher than at December 31, 2005 due to higher off system sales in December 2006 compared to the same period in 2005. In addition, accounts payable and accrued liabilities at the end of 2006 are \$0.9 million higher due to higher prepayments by customers at December 31, 2006 compared to December 31, 2005. Income and other taxes payable at December 31, 2006 are \$75 million higher than at December 31, 2005 primarily due to the current tax liability associated with the receipt of the Methanex termination payment. The gas purchase variance payable at December 31, 2006 has increased by \$2.2 million compared to December 31, 2005 due to gas commodity costs paid by the Company being less than the gas commodity cost rates paid by customers.

CONTRACTUAL OBLIGATIONS

	PAYMENTS DUE BY PERIOD AS OF DECEMBER 31, 2006				
	TOTAL	LESS THAN 1 YEAR	1 - 3 YEARS	4 - 5 YEARS	AFTER 5 YEARS
(\$ in thousands)					
Long Term Debt	76,559	4,880	9,860	12,960	48,859
Purchase Obligations	41,647	35,854	5,726	67	-
Total Contractual Obligations	118,206	40,734	15,586	13,027	48,859

The purchase obligations in the table above represent commitments by the Company to purchase natural gas or transportation service from third parties. 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 2006, the primary sources of funding were the \$23.3 million Methanex termination payment and \$10.1 million of cash generated from operations.

The Company plans to issue new long term debt in 2007 in a minimum amount of \$12.5 million, to supplement its cash generated from operations. These funds will be used for general corporate purposes including the Company's capital program and for expenditures on the KSL Project. The Company last issued long term debt in late 2002 since which time the Company's long term debt has amortized by \$18 million without any corresponding decline in its long term assets. There is no assurance that the Company will be able to raise the planned debt on acceptable terms and conditions.

The Company purchases gas for resale to its core market customers and passes through the commodity cost of gas to those customers without mark-up. The rates charged to core market 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

At the end of 2006, interest coverage using earnings before interest, income taxes, depreciation, and amortization was 3.08 times compared to 3.68 times in the prior year worsening largely as a result of lower earnings and an increase in total interest expense.

FUNDING COSTS

INTEREST EXPENSE

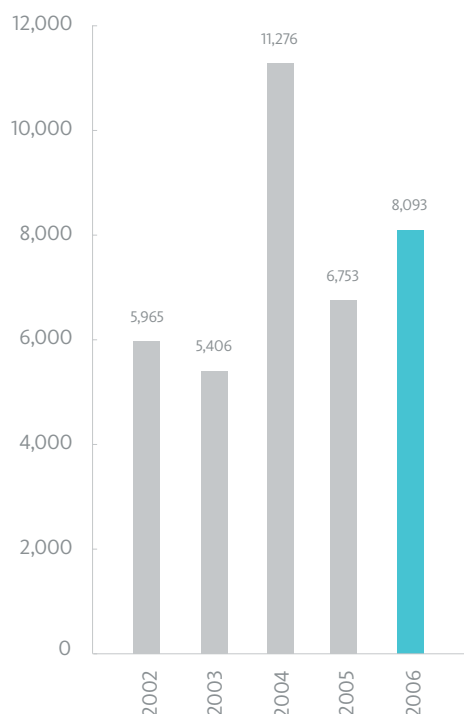
	2006	2005	2004
(\$ in thousands, except percent figures)			
Long term interest expense	6,694	7,083	7,564
Short term interest expense	750	316	450
Total	7,444	7,399	8,014
Effective blended cost of debt (%)	8.1	8.2	8.8

The slight decrease in the effective blended cost of debt is due to lower average long term debt balances as a proportion of total debt, offset by increased interest rates on the Company's floating rate long term debt. The interest rate on short term debt is lower than the interest rate on the Company's long term debt.

CAPITAL EXPENDITURES

Total capital expenditures in 2006 were 20 percent or \$1.3 million higher than those incurred in 2005 and 8 percent above the average level of expenditures for the last five years. In 2006 the Company undertook a \$2.7 million rehabilitation of its facilities in the lower Arden Valley. The work included replacement and/or relocation of several short sections of transmission pipeline to ensure the ongoing integrity of the system. The remainder of the capital expenditures in 2006 was for maintenance capital as well as customer additions to the distribution system on the Northeast system.

CAPITAL EXPENDITURES (\$'000's) 2002-2006



	2006	2005	2004
(\$ in thousands)			
Transmission system	4,572	3,103	7,032
Distribution system	2,119	2,233	2,905
Processing plant	60	112	80
Other	1,342	1,305	1,259
Total	8,093	6,753	11,276

Planned capital spending in 2007 is primarily directed toward installation of distribution mains and services in the Northeast system as well as transmission mainline rehabilitation in the Western system, and is forecast to be approximately \$8.7 million. Contractual commitments have yet to be made for major planned capital expenditures for 2007. These capital expenditures will be funded from cash balances at December 31, 2006, cash flow from operations and a planned long term debt issue in 2007.

The Company's share of planned development expenditures for the KSL Project in 2007 is expected to be approximately \$2.3 million, of which \$0.7 million is expected to be incurred in the first quarter of 2007, to be funded in the same manner as planned capital expenditures.

CAPITAL RESOURCES

COMPOSITION OF CAPITAL STRUCTURE (PERCENT)

AT DECEMBER 31	2006	2005	2004
Preferred shareholders' equity	3.0	2.9	2.9
Common shareholders' equity	48.0	44.6	43.3
Short term debt	3.0	5.8	3.5
Long term debt, including current portion	46.0	46.7	50.3
	100.0	100.0	100.0

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 fixed assets, plus unamortized deferred charges, plus an allowance for working capital, less deferred income taxes. The Commission sets customer rates at a level that is intended to allow the Company to earn its allowed rate of return on common equity. Interim rates for 2006 are based on 36 percent of rate base for the Fort St. John/Dawson Creek and Tumbler Ridge divisions and 40 percent for the Western system.

EQUITY

The book value of the common shares at December 31, 2006 was \$21.92 per share, compared to \$21.43 per share at December 31, 2005.

The Company's preferred shares are currently rated Pfd-3 (low) by Dominion Bond Rating Service ("DBRS"). On September 1, 2005, DBRS placed the ratings of the Company's preferred shares under review with negative implications, following the announcement of the termination of the Methanex agreement.

DIVIDENDS

Preferred dividends totaling \$1.6875 per share were paid in 2006, the same as in 2005. Common dividends totaling \$0.80 per share were paid in 2006, the same as in 2005 and 2004. A total of \$3.2 million preferred and common dividends were paid in 2006, the same as in 2005 and 2004.

SHORT TERM DEBT

The Company has 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 operating line of credit and the risk management facility are collateralized by the pledge of a \$40 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 operating line of credit. At December 31, 2006, the amount available under the facility was \$20 million, of which \$6.9 million had been used. The Company provided covenants to its operating lender, all of which were complied with during 2006.

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.

LONG TERM DEBT

The Company's secured debentures are currently rated BBB (low) by DBRS. On September 1, 2005, DBRS placed the ratings of the Company's secured debentures under review with negative implications, following the announcement of the termination of the Methanex agreement.

OFF BALANCE SHEET ARRANGEMENTS

As of December 31, 2006, the Company had no off-balance sheet arrangements, other than the natural gas hedging contracts described in Financial and Other Instruments below.

TRANSACTIONS WITH RELATED PARTIES

The Company had no transactions with related parties during 2006, 2005 or 2004.

Accounts receivable at December 31, 2006 include \$7,000 due from PTP, and relate to expenditures made by the Company which are to be reimbursed by PTP.

FOURTH QUARTER

The following table compares the results for the fourth quarters of 2006 and 2005:

	Q4 2006	Q4 2005	PERCENT CHANGE
(\$ in thousands, except per share and per GJ figures)			
Deliveries (TJ)			
Sales	2 466	2 191	12.6
Transportation service	1 548	3 293	(53.0)
Total Deliveries	4 014	5 484	(26.8)
Customers at period end	39,511	39,295	0.01
Weighted average cost of gas purchased (\$ per GJ)			
	7.25	10.20	(28.9)
Operating revenues	46,190	49,621	(6.9)
Operating margin, consisting of Operating revenues less cost of sales			
	14,074	14,259	(1.3)
Income before income taxes	4,014	5,042	(20.4)
Net income	2,319	3,311	(30.0)
Operating cash flow	3,711	5,278	(29.7)
Basic Earnings per common share	0.61	0.89	(31.5)
Dividends paid per common share	0.20	0.20	-

Net income for the quarter ended December 31, 2006 was \$2.3 million, compared with \$3.3 million for the quarter ended December 31, 2005. After providing for preferred share dividends, earnings per common share in the fourth quarter of 2006 were \$0.61, compared with \$0.89 for the quarter ended December 31, 2005. Included in the results for the fourth quarter of 2006 are charges, net of income taxes, totalling \$0.6 million relating to the Company's share of KSL Project expenditures, or \$0.15 per share. In addition, operating and maintenance expenses were higher by \$0.2 million in the fourth quarter of 2006 compared to the same period in 2005.

Operating revenues in the fourth quarter of 2006 decreased to \$46.2 million as compared with \$49.6 million in the same period in 2005. The decrease in operating revenue in the fourth quarter is primarily attributed to a decrease in transportation services of \$3.5 million, offset by \$1.7 million of amortization of the Methanex termination payment deferral, as well as a reduction in off system sales of \$0.7 million. While sales revenue from residential and commercial customers was \$0.9 million lower in the fourth quarter of 2006, deliveries to those customer classes were 16 percent higher, reflecting weather that was 21 percent colder in 2006 compared to 2005 and a lower commodity cost of gas embedded in rates.

Operating margin in the fourth quarter of 2006 decreased to \$14.1 million, compared to \$14.3 million in the corresponding period in 2005, due to the reduction in transportation service revenue resulting from the Methanex closure, offset by higher margin recoveries from the other customer classes.

Capital expenditures in the fourth quarter of 2006 were \$2.4 million, compared to \$3.0 million in the comparable period in 2005, due to fewer mainline rehabilitation expenditures in the fourth quarter of 2006 compared to the same period in 2005.

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 55 percent of the Company's operating revenues for 2006. 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.

CHANGES IN ACCOUNTING POLICIES INCLUDING INITIAL ADOPTION

CHANGES ADOPTED IN 2005

Disclosure by entities subject to rate regulation

Effective December 31, 2005, the Company adopted, on a prospective basis, the new Accounting Guideline AcG-19, Disclosure by Entities subject to Rate Regulation, which applies to years ending on or after December 31, 2005. AcG-19 provides guidance about certain aspects of the disclosure and presentation of information of entities providing services or products for which customer rates are established or approved by a regulator. The objective is to ensure that financial statement users are better informed about the existence, nature and effects of all forms of rate regulation. If rate regulation has an impact on the accounting treatment of a transaction, the entity should make mention of it and provide additional information about the impact on its financial statements.

CHANGES APPLICABLE IN 2007

Comprehensive income

In April 2005, the Canadian Institute of Chartered Accountants (CICA) issued Section 1530 of the CICA Handbook, "Comprehensive Income", which applies to years beginning on or after October 1, 2006. The Section establishes standards for reporting and display of comprehensive income, which is the change in equity (net assets) of an enterprise during a period from transactions from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. The Company intends to comply with the new presentation standards as of January 1, 2007.

Financial instruments – recognition and measurement

In April 2005, the CICA issued Section 3855 of the CICA Handbook, "Financial Instruments – Recognition and Measurement", which applies to years beginning on or after October 1, 2006. This Section establishes when a financial instrument should be recognized in the balance sheet and the valuation method – fair value or cost-based value. It also specifies the presentation of gains and losses on financial instruments. The Company does not expect the adoption of this standard will have a material impact on net income.

Hedges

In April 2005, the CICA issued Section 3865 of the CICA Handbook, "Hedges", effective for years beginning on or after October 1, 2006. This Section establishes standards for when and how hedge accounting may be applied. Hedging is an activity designed to modify an entity's exposure to one or more risks. Hedge accounting modifies the normal basis for recognizing the gains, losses, revenues and expenses associated with a hedged item or a hedging item in an entity's income statement. It ensures that counterbalancing gains, losses, revenues and expenses are recognized in the same period. The Company does not expect that the adoption of this standard will have a material impact on its net income.

FINANCIAL INSTRUMENTS 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 utilizes interest rate hedging contracts to reduce the volatility of the interest expense associated with its floating rate debt instruments. As of December 31, 2006, the Company had no interest rate hedging contracts outstanding.

During the second quarter the Company completed its annual gas contracting and gas supply price risk management plan and filed it with the Commission for review and acceptance. The annual gas contracting plan covered proposed gas purchases over the November 1, 2006 to October 31, 2007 period while the gas price risk management plan provided for hedging gas purchases over the November 1, 2006 through October 31, 2008 period. The Company proposed implementing the hedges in stages over the May

2006 to January 2008 period. The Commission accepted the plan as filed. Each hedging transaction was approved by the Company's price risk management plan committee and reported on a monthly basis to the Commission.

At December 31, 2006, the Company had outstanding fixed price contracts, natural gas swap contracts, collar contracts and call options relating to natural gas supply as follows:

FINANCIAL INSTRUMENT	NOTIONAL QUANTITY (GJ'S)	PERCENT OF ANNUAL GAS PURCHASES	DELIVERY PERIOD	PRICE RANGE (PER GJ)	ESTIMATED FAIR VALUE RECEIVABLE (PAYABLE)
					(\$ in thousands)
Fixed price contracts	450 000	4.5	Jan. - Mar. 2007	\$7.317	(542)
Natural gas swap contracts	4 308 000	43.4	Jan. 2007 - Oct. 2008	\$6.84 to \$10.28	(5,876)
Collar contracts	500 500	5.0	Jan. 2007 - Oct. 2008	Floors from \$6.05 to \$8.55; Caps from \$8.65 to \$10.65	250
Call options	174 500	1.8	Jan. - Oct. 2007	Caps from \$8.40 to \$8.99	53
Total	5 433 000	54.7			(6,115)

The fair value reflects the estimated amounts that the Company would receive or pay at December 31, 2006 to terminate the fixed price contracts, natural gas swap contracts, costless collars or call options, based on the estimated 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 gas hedging instruments would be treated as part of the flow through of gas supply costs in customer rates.

At December 31, 2005, the Company had outstanding fixed price contracts, natural gas swap contracts and call options relating to natural gas supply as follows:

FINANCIAL INSTRUMENT	NOTIONAL QUANTITY (GJ'S)	PERCENT OF ANNUAL GAS PURCHASES	DELIVERY PERIOD	PRICE RANGE (PER GJ)	ESTIMATED FAIR VALUE RECEIVABLE (PAYABLE)
					(\$ in thousands)
Fixed price contracts	450 000	4.6	Jan. - Mar. 2006	\$10.00	(167)
Natural gas swap contracts	1 193 000	12.1	Jan. - Oct. 2006	\$7.85 to \$10.60	1,670
Call options	1 219 500	12.3	Jan. - Mar. 2006	Caps from \$10.00 to \$15.00	633
Total	2 862 500	29.0			2,136

The fair value reflects the estimated amounts that the Company would receive or pay at December 31, 2005 to terminate the fixed price contracts or collar contracts based on the estimated net cash flows under the terms of each contract.

Natural gas prices for 2007 forecast gas purchases by the Company, based on forward gas prices as at February 16, 2007, are forecast to be approximately 3.4 percent (\$0.26 per GJ) higher than the actual corresponding prices in 2006.

CEO AND CFO CERTIFICATIONS

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), on a timely basis so that appropriate decisions can be made regarding public disclosure.

An evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures was conducted as of December 31, 2006, by and under the supervision of management, including the CEO and the CFO. Based on this evaluation, the CEO and the CFO have concluded that the Company's disclosure controls and procedures, as defined by Multilateral Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, are effective to ensure that information required to be disclosed in reports filed or submitted under Canadian securities legislation is recorded, processed, summarized and reported within the time period specified in those rules and forms.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with Canadian generally accepted accounting principles ("GAAP"). Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company.

An evaluation of the design of the Company's internal control over financial reporting was conducted as of December 31, 2006, by and under the supervision of management, including the CEO and the CFO. Based on this evaluation, the CEO and the CFO have concluded that the Company's design of internal control over financial reporting, as defined by Multilateral Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, is sufficient to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with Canadian GAAP.

There have been no changes in internal control over financial reporting during the quarter ended December 31, 2006 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

OUTSTANDING SHARE DATA

At February 19, 2007, there were 200,000 preferred shares and 3,641,180 common shares outstanding. The common shares are the only issued voting securities of the Company, and it has no securities outstanding which may be converted into voting or equity securities.

RISK FACTORS

Industrial customer concentration and potential for termination of contracts

In 2006, 24 percent of energy deliveries were made to the Company's three largest industrial customers, compared to 70 percent in 2005. The Company's contract with Methanex was terminated effective February 28, 2006. The Company's contract with West Fraser specifies a December 31, 2013 expiry date subject to termination prior to that date upon payment of an amount calculated in accordance with the early termination provisions of the contract, or without payment if West Fraser notifies the Company prior to July 1, 2008 of its intent to close the facility and the closure activities are completed prior to December 31, 2009. Deliveries to West Fraser accounted for approximately 16 percent of annual deliveries in 2006.

Alcan, whose deliveries account for approximately 8 percent of annual deliveries, has a firm gas transportation agreement that would expire October 31, 2008 if either party gives twelve months notice of termination by October 31, 2007. 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 and price competitiveness 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 largely dependent upon industrial customers for its economic stability. These customers produce commodities that are subject to world commodity price fluctuations. 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 system service area many of the Company'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.

Commodity price and supply risk

Over the last three years, the commodity cost of natural gas has been highly volatile. The Company's average cost of natural gas in 2006 was approximately 5 percent lower than in 2005 and 23 percent higher than in 2004. When prices are high, the prospects of fuel-switching and increased energy conservation pose a risk, as other energy sources can become more cost competitive. Fluctuations in the price of natural gas may increase the Company'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, and/or failure of a counterparty to perform.

Usage risks

Natural gas competes with other forms of energy available to the Company'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 Company's service areas. 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 system region.

Regulatory risk

The Company's asset base is subject to regulation by the Commission (see "Regulatory Activities"). 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 charges 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 rate stabilization adjustment mechanism deferral account approved by the Commission 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 Commission 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 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.

Liquidity, cash flow, and capital availability risks

The Company's credit facilities include a \$20 million operating line and a \$15 million risk management facility. The operating line is subject to borrowing base requirements which may restrict the amount that the Company 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 that can be borrowed 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 the Company can pay in the absence of access to new long term debt, which is exacerbated by expenditures on the KSL Project, in the absence of access to new long term debt.

The Company is currently relying on operating cash flow to fund capital expenditures, scheduled amortizations of long term debt, payment of dividends, and KSL Project development expenditures. While operating cash flow has been adequate for those purposes, there is no assurance that it will be in the future. As noted in the *Liquidity* section under Funding Requirements, the Company is planning a new debt issue for 2007 to supplement its operating cash flow; however there is no assurance that the new debt issue can be completed on acceptable terms and conditions. Any constraint on the Company's ability to raise capital, including a credit downgrade, may negatively impact its investment and development activities, capital expenditures and hedging program.

Facility and insurance risk

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 or increased maintenance or capital costs.

The Company maintains insurance against exposures 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 for damage to the pipeline caused by slides, washouts, and other natural events, the Company's deductibles have remained high. Depending on the number and severity of future outages, the financial impact on the Company could be material.

Environmental and safety risks

The Company 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, the Company could be exposed to significant operational disruptions and environmental liability in the event of an accident involving natural gas. The Company believes it has taken all reasonable and prudent steps to minimize its exposure in the case of safety or environmental incidents.

Derivatives risk

The Company uses derivative and other financial instruments in connection with the management of gas supply prices and interest rates. Forward, future, swap, fixed price and option contracts are used to manage the impact of market fluctuations on assets, liabilities or other contractual commitments. The Company 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 the Company's valuation and potentially resulting in financial losses. This risk could affect the Company's liquidity, and regulatory approval would be required for the recovery of related costs through future rate adjustments.

Additional information concerning the Company, including its most recent Annual Information Form, can be found at www.sedar.com.

TO THE SHAREHOLDERS OF PACIFIC NORTHERN GAS LTD.

The consolidated financial statements and all information in this report are the responsibility of management and have been approved by the Board of Directors. These consolidated financial statements have been prepared by management in conformity with accounting principles generally accepted in Canada ("Canadian GAAP") and, where appropriate, include certain estimated amounts that are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management has prepared Management's Discussion and Analysis which is based on the Company's financial results prepared in accordance with Canadian GAAP. It compares the Company's financial performance in 2006 to 2005 and should be read in conjunction with the consolidated financial statements and accompanying notes.

Management has developed and maintains a system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. The internal accounting control process includes management's communication to employees of policies which govern ethical business conduct.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and for final approval of the consolidated financial statements. The Board of Directors performs this responsibility primarily through its Audit Committee.

The Audit Committee is comprised solely of unrelated, independent directors and meets regularly with management and the external auditors as well as independently with the external auditors to review the consolidated financial statements, the Auditors' Report and other auditing and accounting matters. The Audit Committee reviews the Annual Report, including the consolidated financial statements, before the consolidated financial statements are submitted to the Board of Directors for approval. The Audit Committee reports its findings to the Board of Directors. The external auditors have free access to the Audit Committee without obtaining prior management approval.

With respect to the external auditors, Deloitte & Touche LLP, the Audit Committee approves the terms of engagement and reviews the annual audit plan, the Auditors' Report and results of the audit. It also recommends to the Board of Directors the external audit firm to be appointed by the shareholders.

The independent external auditors, Deloitte & Touche LLP, have been appointed by the shareholders to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's financial position, results of operations and cash flows in accordance with Canadian GAAP. The auditors' report of Deloitte & Touche LLP outlines the scope of their examination and their opinion on the consolidated financial statements.



ROY G. DYCE
President and Chief Executive Officer

February 19, 2007



ELIZABETH A. FLETCHER
Chief Financial Officer

TO THE SHAREHOLDERS OF PACIFIC NORTHERN GAS LTD.

We have audited the consolidated balance sheets of **Pacific Northern Gas Ltd.** as at December 31, 2006 and 2005 and the consolidated statements of income, retained earnings and cash flows for each of the years in the three year period ended December 31, 2006. 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, 2006 and 2005 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2006 in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

CHARTERED ACCOUNTANTS

Vancouver, Canada

February 12, 2007

consolidated statements of income

YEARS ENDED DECEMBER 31	2006	2005	2004
(\$ in thousands, except for per share data)			
Operating revenues			
Gas sales and transportation services	100,104	103,280	93,295
Off system sales	32,713	56,159	43,949
Other (note 3)	6,031	511	511
	138,848	159,950	137,755
Cost of sales			
Gas sales	58,405	55,128	45,005
Off system sales	32,713	56,159	43,949
	91,118	111,287	88,954
Operating margin	47,730	48,663	48,801
Operating and maintenance	10,386	10,756	12,093
Administrative and general	6,640	6,410	6,623
Amortization of deferred charges	691	755	763
Municipal and other taxes	4,755	4,120	3,941
Depreciation	7,687	8,011	7,877
	30,159	30,052	31,297
Operating income	17,571	18,611	17,504
Investment and other income	787	27	48
	18,358	18,638	17,552
Income deductions			
Interest on long term debt	6,694	7,083	7,564
Interest on short term debt	750	316	460
Project development expenditures and other income deductions (note 12)	3,016	165	-
	10,460	7,564	8,024
Income before income taxes	7,898	11,074	9,528
Income taxes (note 5) – current	10,052	2,775	2,646
– deferred	(7,105)	1,639	1,474
	2,947	4,414	4,120
Net income for the year	4,951	6,660	5,408
For common shares			
Net income for the year	4,951	6,660	5,408
Dividends on preferred shares	337	337	337
Net income applicable to common shares, basic and diluted	4,614	6,323	5,071
Earnings per common share (note 1)			
Basic	1.27	1.75	1.41
Diluted	1.26	1.72	1.38
Weighted average number of common shares outstanding			
Basic	3,631,464	3,619,579	3,596,706
Effect of dilutive stock options	45,213	56,592	70,389
Diluted	3,676,677	3,676,171	3,667,095

See accompanying notes

AS AT DECEMBER 31	2006	2005
(\$ in thousands)		
ASSETS (notes 7 and 8)		
Current assets		
Cash and short term investments	11,574	-
Accounts receivable (note 3)	29,907	28,831
Income taxes recoverable (note 5)	-	375
Inventories of supplies and natural gas	2,603	2,688
Prepaid expenses	4,334	1,800
	48,418	33,694
Plant, property and equipment (note 4)	172,996	171,351
Deferred charges (note 2)		
Debt costs	499	615
Rate stabilization adjustment mechanism	2,936	2,311
Pipeline rehabilitation costs	859	1,011
Deactivated assets	4,667	5,050
Other	(310)	1,178
	8,651	10,165
	230,065	215,210
LIABILITIES Commitments and guarantees (notes 15 and 16)		
Current liabilities		
Bank indebtedness (note 7)	5,075	10,159
Accounts payable and accrued liabilities	22,094	21,121
Gas purchase variance payable (note 2)	3,115	881
Income and other taxes payable	10,377	3,263
Methanex termination payment deferral, current portion (note 3)	4,065	-
Long term debt due within one year (note 8)	4,880	4,880
	49,606	40,304
Non-current liabilities (note 6)	477	224
Methanex termination payment deferral, non-current portion (note 3)	8,096	-
Long term debt (note 8)	71,679	76,560
Deferred income taxes (note 5)	15,430	15,430
	95,682	92,214
	145,288	132,518
SHAREHOLDERS' EQUITY		
Preferred shares (note 9)	5,000	5,000
Common shares (notes 10 and 11)	9,103	9,065
Contributed surplus (notes 10 and 11)	3,168	2,828
Retained earnings	67,506	65,799
Common shareholders' equity	79,777	77,692
	84,777	82,692
	230,065	215,210

See accompanying notes

On behalf of the Board:



ROY G. DYCE
Director



ROBERT F. CHASE
Director

consolidated statements of cash flows

YEARS ENDED DECEMBER 31	2006	2005	2004
(\$ in thousands)			
OPERATING ACTIVITIES			
Net income for the year	4,951	6,660	5,408
Add (deduct) items not involving cash:			
Deferred income taxes	(7,105)	1,639	1,474
Depreciation and amortization (note 17)	8,494	8,905	8,800
Amortization of Methanex termination payment deferral, net of income taxes (note 3)	(3,890)	-	-
Stock option expense (note 11)	179	132	93
Deferred income taxes on deferred charges	7,105	(1,639)	(1,474)
Imputed interest on deferred charges	416	62	(25)
Other	253	(63)	358
Operating cash flow	10,403	15,696	14,634
Non-cash working capital changes (note 17)	7,171	(3,827)	1,708
Net cash provided by operating activities	17,574	11,869	16,342
INVESTING ACTIVITIES			
Additions to plant, property and equipment (note 4)	(8,093)	(6,753)	(11,276)
Increase in deferred charges and credits (note 2)	(269)	(1,799)	(1,071)
Methanex termination payment deferral, net of income taxes (note 3)	15,372	-	-
Net cash provided by (used in) investing activities	7,010	(8,552)	(12,347)
FINANCING ACTIVITIES			
Increase (decrease) in bank indebtedness	(5,084)	4,113	3,146
Repayment of long term debt	(4,881)	(4,380)	(4,380)
Issue of common shares (note 10)	199	185	143
Dividends paid	(3,244)	(3,235)	(3,217)
Net cash used in financing activities	(13,010)	(3,317)	(4,308)
Decrease in cash and cash equivalents during the year	11,574	-	(313)
Cash and cash equivalents, beginning of year	-	-	313
Cash and cash equivalents, end of year	11,574	-	-

Supplemental cash flow information (note 17)

See accompanying notes

consolidated statements of retained earnings

YEARS ENDED DECEMBER 31	2006	2005	2004
(\$ in thousands)			
Balance, beginning of year	65,799	62,374	60,183
Net income for the year	4,951	6,660	5,408
	70,750	69,034	65,591
Preferred share dividends	337	337	337
Common share dividends	2,907	2,898	2,880
	3,244	3,235	3,217
Balance, end of year	67,506	65,799	62,374

See accompanying notes

1 SUMMARY OF ACCOUNTING POLICIES

REGULATION AND RELATED DISCLOSURE

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 for non rate-regulated entities.

The financial effects of rate regulation relate principally to balances and the accounting policies noted below. Disclosure of the impact of rate regulation on these balances and policies are included in the related notes as referenced:

- ~ Deferred charges and liabilities (notes 2 and 4)
- ~ Property, plant and equipment and related depreciation rates (note 4)
- ~ Income taxes (notes 2 and 5)
- ~ Employee future benefit plans for post-retirement non-pension benefits (notes 2 and 6)
- ~ Hedges, derivatives and other financial instruments (note 2)

PRINCIPLES OF CONSOLIDATION

The financial statements of entities which are controlled by the Company through voting equity interest, referred to as subsidiaries, are consolidated. Variable interest entities ("VIEs"), which include, but are not limited to, special purpose entities, trusts, partnerships and other legal structures, as defined by the Accounting Standards Board in Accounting Guideline 15 "Consolidation of Variable Interest Entities", are entities in which equity investors do not have the characteristics of a "controlling financial interest" or there is not sufficient equity at risk for the entity to finance its activities without additional subordinated financial support. VIEs are subject to consolidation by the primary beneficiary who will absorb the majority of the entities' expected losses and/or residual returns. The Company has determined that it is not the primary economic beneficiary of any VIEs.

The consolidated financial statements include the accounts of Pacific Northern Gas Ltd., its wholly owned subsidiary Pacific Northern Gas (N.E.) Ltd., as well as the Company's proportionate interest in the assets, liabilities, revenue and expenses of all incorporated and unincorporated joint ventures, to the extent that the Company is not the primary economic beneficiary and they are subject to joint control. All intercompany transactions and balances are eliminated on a pro rata basis for joint ventures.

Significant subsidiaries and joint ventures are as follows, as at December 31:

DIRECT AND INDIRECT INTEREST HELD BY THE COMPANY (PERCENT)		
	2006	2005
Subsidiaries:		
Pacific Northern Gas (N.E.) Ltd.	100	100
Joint Ventures and Non-Controlled Partnerships (note 12):		
Pacific Trail Pipelines Limited Partnership	50	-
Pacific Trail Pipelines Management Inc.	50	-

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.

Significant balances impacted by estimates include operating revenues which include estimates of customer usage from the last meter reading date to the end of the reporting period, and accounts receivable which are recorded net of an estimated allowance for doubtful accounts. Actual results could differ from these estimates.

REVENUE RECOGNITION

The Company's operations are subject to rate-regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as mandated by the Commission. This may result in the recognition of regulatory assets and liabilities.

1 SUMMARY OF ACCOUNTING POLICIES (CONT'D)

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 CASH EQUIVALENTS

Cash and cash equivalents are held for the purpose of meeting short term cash commitments and include bank balances, and bankers' acceptances and term deposits with maturities of less than 90 days.

INVENTORIES OF SUPPLIES AND NATURAL GAS

Inventories of natural gas (line-pack) are valued at the supply rate approved by the Commission. The rate is adjusted quarterly in accordance with a method approved by the Commission whereby all costs are billed entirely to customers, including the impact of the risk management activities related to the price of natural gas. Inventory of supplies 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.

DEFERRED CHARGES AND LIABILITIES

The Company defers certain charges which the Commission or contractual arrangement require or permit to be recovered through future rates. Deferred charges and credits are amortized over various periods as approved by the Commission, depending on the nature of the charges or credits (see note 2).

Deferred charges include long term debt issue costs which are amortized over the term of the related debt which approximates the effective interest method.

DEVELOPMENT ACTIVITIES

The costs related to development activities are capitalized except in those cases where the Company does not have reasonable assurance that these costs will be recovered in the future.

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 approved by the Commission (note 4).

ASSET RETIREMENT OBLIGATIONS

The fair value of asset retirement obligations associated with the retirement of long-lived assets is recognized in the period when it can be reasonably determined. The fair value, which approximates the cost a third party would charge in performing the tasks necessary to retire such assets, is recognized at the present value of expected future cash flows and is added to the carrying value of the associated asset and depreciated over the asset's useful life. The liability is accreted over time through periodic charges to earnings and is reduced by actual costs of decommissioning and reclamation.

The Company's natural gas transmission and distribution long-lived assets are comprised principally of mains, service lines, compressors, and measuring and regulating equipment. No amount has been recorded for asset retirement obligations relating to the Company's assets as it is not possible to make a reasonable estimate of the fair value of the liability due to the indeterminate timing and scope of the asset retirements. Management expects all retirement costs associated with the regulated assets will be recovered through tolls in future periods and therefore any liability recorded would be offset by an asset.

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 5).

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 the 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

The Company uses derivative and other financial instruments in connection with the management of gas supply and interest rates. The Company enters into forward, future, swap, fixed price and option contracts to manage the exposure to the volatility of natural gas prices for sales customers. The prices paid for natural gas are based on variable indices. The instruments used make it possible to fix, or define, the price of natural gas for delivery to customers. The gains or losses on these instruments are included in gas supply costs as these costs are recognized, and are recovered through the gas supply rate in accordance with the method approved by the Commission.

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.

1 SUMMARY OF ACCOUNTING POLICIES (CONT'D)

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 135,100 (2005 - 96,000; 2004 - 84,200) 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 prices were greater than the average market price of the common shares.

STOCK BASED COMPENSATION

Stock options granted after January 1, 2003 are accounted for under the fair value method. Under this method, compensation expense is measured at fair value at the grant date using the Black-Scholes option pricing model and recognized over the vesting period with a corresponding credit to contributed surplus. Stock options granted prior to January 1, 2003 continue to be accounted for as capital transactions when the options are exercised, which does not give rise to compensation expense.

NEW ACCOUNTING STANDARDS

Applied in 2005

Effective December 31, 2005, the Company adopted, on a prospective basis, the new Accounting Guideline AcG-19, *Disclosure by Entities subject to Rate Regulation*, which applies to years ending on or after December 31, 2005. AcG-19 provides guidance about certain aspects of the disclosure and presentation of information of entities providing services or products for which customer rates are established or approved by a regulator. The objective is to ensure that financial statement users are better informed about the existence, nature and effects of all forms of rate regulation. If rate regulation has an impact on the accounting treatment of a transaction, the entity should make mention of it and provide additional information about the impact on its financial statements (see note 2).

Applicable in 2007

Comprehensive income

In April 2005, the Canadian Institute of Chartered Accountants (CICA) issued Section 1530 of the CICA Handbook, "Comprehensive Income", which applies to years beginning on or after October 1, 2006. The Section establishes standards for reporting and display of comprehensive income, which is the change in equity (net assets) of an enterprise during a period from transactions from non-owners sources. The Company intends to comply with the new presentation standards as of January 1, 2007.

Financial instruments – recognition and measurement

In April 2005, the CICA issued Section 3855 of the CICA Handbook, "Financial Instruments – Recognition and Measurement," which applies to years beginning on or after October 1, 2006. This Section establishes when a financial instrument should be recognized in the balance sheet and the valuation method – fair value or cost-based value. It also specifies the presentation of gains and losses on financial instruments. The Company does not expect that the adoption of this standard will have a material impact on net income.

Hedges

In April 2005, the CICA issued Section 3865 of the CICA Handbook, "Hedges", effective for years beginning on or after October 1, 2006. This Section establishes standards for when and how hedge accounting may be applied. Hedging is an activity designed to modify an entity's exposure to one or more risks. Hedge accounting modifies the normal basis for recognizing the gains, losses, revenues and expenses associated with a hedged item or a hedging item in an entity's income statement. It ensures that counterbalancing gains, losses, revenues and expenses are recognized in the same period. The Company does not expect that the adoption of this standard will have a material impact on its net income.

COMPARATIVE FIGURES

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

2 FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

The Company and its subsidiary are regulated by the Commission. Customer rates are set under a cost of service methodology that allows revenues to be set to recover the Company's forecast costs and to earn a rate of return on common equity. Applications for changes to rates are made annually and are submitted to the Commission for their review and approval.

Forecast costs include gas commodity and transportation, operation and maintenance, depreciation, property taxes, interest and income taxes. The rate base is the average level of investment in all recoverable assets used in gas transmission and distribution, and an allowance for working capital. Under cost of service regulation, it is the responsibility of the Company to demonstrate to the Commission the prudence of the costs it has incurred. For 2006, the Company's average approved rate of return on the rate base was 8.58 percent after tax, and the average approved rate of return on common equity was 9.40 percent after tax, based on weighting using the respective rate bases of the Company and its subsidiary. The Company's deemed common equity was 40 percent, but the deemed common equity of its subsidiary was 36 percent in 2006.

REGULATORY ASSETS AND LIABILITIES

Certain regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate-setting process. In the absence of rate regulated accounting, generally accepted accounting principles would not permit deferral of regulatory assets and therefore the earnings impact would be recorded in the period of recovery. Long term regulatory assets are recorded in deferred charges in the consolidated balance sheets.

Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting process. The treatment under generally accepted accounting principles of regulatory liabilities and the resulting earnings impact is the same as that under rate regulated accounting because the liabilities represent contractual obligations. Regulatory liabilities are shown on the consolidated balance sheets in liabilities.

REGULATORY RISK AND UNCERTAINTIES AFFECTING RECOVERY OR SETTLEMENT

The regulatory assets and liabilities recorded in the financial statements are based upon an expectation of the future actions of the regulator. To the extent that the regulator's future actions are different from the Company's expectations, the timing and amount of recovery or settlement of amounts recorded on the consolidated balance sheets could be significantly different from the timing and amounts that are eventually recovered or settled.

FINANCIAL STATEMENT EFFECTS

In order to recognize the economic effects of the actions or expected actions of the regulator, the timing of recognition of certain revenues and expenses may differ from that otherwise expected under generally accepted accounting principles ("GAAP") for non rate-regulated entities.

The income statement effects noted in the following table indicates the effect, either increase or (decrease), on 2006 or 2005 after tax net income as a result of the treatment under rate regulated accounting as compared to the corresponding treatment under GAAP for non rate-regulated entities. The carrying amount for 2006 and 2005 is the cost amount of the deferral, less income taxes and accumulated amortization, at December 31, 2006 and December 31, 2005, respectively.

2 FINANCIAL STATEMENT EFFECTS OF RATE REGULATION (CONT'D)

DEFERRED CHARGES AND LIABILITIES

DESCRIPTION	PERIOD OF RECOVERY	INCREASE	CARRYING	INCREASE	CARRYING
		(DECREASE)	AMOUNT	(DECREASE)	AMOUNT
		IN NET	DECEMBER	IN NET	DECEMBER
		INCOME	31	INCOME	31
		2006	2006	2005	2005
(\$ in thousands)					
Deferrals included in rate base					
Rate Stabilization Adjustment Mechanism ¹	Over three-years, based on forecast customer deliveries	1,341	2,936	876	2,311
Pipeline rehabilitation costs²:					
Extraordinary pipeline losses	Straight-line over 10 years, between 2007 and 2014	-	53	-	62
Pipeline breaks	Straight-line over 10 years, between 2007 and 2014	-	647	21	739
Stress Corrosion Cracking	Straight-line over 10 years, between 2007 and 2016	8	159	42	210
Total pipeline rehabilitation costs		8	859	63	1,011
Other rate base deferrals:					
Preliminary surveys and investigations ³	Depreciated over the life of the related asset commencing when placed into service	(350)	5	350	355
Property taxes ⁴	1 year, 2007	(47)	(47)	80	80
Industrial customer deliveries ⁵	Straight-line over 3 years, 2007 to 2009	30	264	311	696
Commission hearing costs ⁶	1 year, 2007	(107)	361	485	409
Other	Straight-line over 3 to 10 years	99	79	143	252
Total other rate base deferrals		(375)	662	1,369	1,792
Deferrals excluded from rate base					
Deactivated assets ⁷	Straight-line over 10 years, to 2015	285	4,667	5,050	5,050
Other deferrals excluded from rate base:					
Depreciation adjustment liability for prior year retirements ⁸	Straight-line over 1 to 2 years	(1,293)	(1,272)	(637)	(637)
Propane air plant ⁹	Straight-line over 10 years, to 2014	26	376	(318)	412
Interest ¹⁰	Straight-line over 2 years, 2007 to 2008	101	8	(186)	(315)
Other	1 year, 2007	(85)	(84)	(59)	(74)
Other deferrals excluded from rate base		(1,251)	(972)	(1,200)	(614)
Total deferred charges		8	8,152	6,158	9,550
Regulatory liabilities excluded from rate base					
Gas purchase variance payable ¹¹	Based on forecast deliveries over 1 year	(3,615)	(3,115)	(283)	(2,232)
Methanex Termination Payment	Straight-line over the period March 1, 2006 to October 31, 2009	(12,161)	(12,161)	-	-
Total regulatory liabilities excluded from rate base		(15,776)	(15,276)	(283)	(2,232)

1. Rate Stabilization Adjustment Mechanism

The Company is authorized by the Commission to maintain a rate stabilization adjustment mechanism ("RSAM") deferral account to mitigate the effect on its earnings of volatility in deliveries to certain customers caused principally by weather and natural gas cost volatility. The RSAM deferral account accumulates the margin impact of variations in the actual versus forecast use for residential and small commercial customers. Balances in the RSAM deferral account are recovered in customer rates over a three year period based on forecast deliveries. During 2006, approximately \$716,000 of the December 31, 2005 RSAM balance was recovered in customer rates (2005 - \$353,000; 2004 - \$282,000).

2. Pipeline rehabilitation costs

The cost of carrying out temporary repairs of pipeline breaks as well as the related undepreciated net book value of pipeline assets destroyed as a result of pipeline breaks is recorded in deferral accounts for future recovery from customers. In addition, the cost of investigative work and repair of pipeline assets at risk due to stress corrosion cracking or other material defects is deferred for future recovery in customer rates.

3. Preliminary surveys and investigations

The Company defers costs associated with the development of new projects that would be beneficial to its customers. In 2005, the Company commenced preliminary study and investigation of a project to loop its main line transmission system from Kitimat to Summit Lake (the "KSL Project"). The KSL Project would be required to provide gas transportation services for liquefied natural gas to be imported and regasified at the proposed Kitimat LNG Inc. terminal to be located on the Douglas Channel approximately 15 kilometers southwest of Kitimat. In 2005, the Company incurred costs of \$0.9 million associated with the KSL Project, which were deferred with the approval of the Commission. On July 17, 2006, the Company announced the formation of Pacific Trail Pipelines Limited Partnership ("the partnership"), a partnership between the Company and Galveston LNG Inc., the parent company of Kitimat LNG Inc., for the purpose of developing the KSL Project. The development costs deferred prior to the formation of the partnership were transferred as part of the Company's initial investment in the partnership and subsequently expensed by the partnership, pursuant to the partnership agreement. As the partnership is not a regulated utility, there is no longer reasonable assurance that these costs will be recovered in the future.

4. Property taxes

As directed by the Commission, a deferral account is used to recover the difference between actual and forecast property taxes, to be recovered from (or refunded to) customers in rates over the following year.

5. Industrial customer deliveries

As directed by the Commission, a deferral account is used to recover the lost margin from certain large industrial customers whose deliveries varied from the forecast used for rate setting. The amount deferred during the year ended December 31, 2003 is being amortized over three years, commencing in 2004. The credit amount deferred in 2004 was amortized entirely in 2005. Amortization of \$476,000 has been included in net income during 2006 related to these deferred costs (2005 - \$230,000). The Company has applied to the Commission for a three-year amortization period for the 2006 deferral, commencing in 2007.

6. Commission hearing costs

The Company's annual revenue requirements application contains a forecast of the costs that the Company will incur relating to the Commission's review of the application. The total actual costs are usually not known by the Company until a few months after the conclusion of the Commission's review process and the implementation of new customer rates. Therefore, customer rates reflect forecast costs of the review process and the Company records in a deferral account the difference between forecast and actual costs for future recovery from or refund to customers.

7. Deactivated assets

In its 2006 revenue requirements application, the Company identified plant, property and equipment assets which would not be required on an ongoing basis to provide service to its customers, having regard to the closure of the Methanex Corporation plant in late 2005 (see note 3). In 2006, the Commission approved the removal from rate base of compressor facilities, pipeline loops and various other fixed assets with a net book value of \$5.05 million. This amount was transferred to a non-rate base, interest bearing deferral account effective December 31, 2005. The deferral account is being amortized on a straight-line basis over ten years commencing in 2006.

8. Depreciation adjustment for prior year retirements

As a result of detailed analysis of property, plant and equipment cost and retirement records conducted in 2005 and 2006, various assets were identified as retired or disposed in prior years, between 1989 and 2001; however, no retirement was recorded at the time. Approximately \$1,239,000 (2005 - \$637,000) of accumulated depreciation was identified which should not have been recorded in the years 1989 to 2005. The Company reversed this accumulated depreciation in 2005 and 2006, and transferred the balance to a deferred credit. The deferred credit recorded in 2005 was refunded to customers, with the approval of the Commission, in 2006. The Company has applied to the Commission to allow the deferred credit recorded in 2006 to be refunded to customers over a one or two year period, commencing in 2007. The ultimate realization of this deferred credit is subject to a future decision of the Commission.

2 FINANCIAL STATEMENT EFFECTS OF RATE REGULATION (CONT'D)

9. Propane air plant

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. As part of the negotiated settlement process for determining 2005 customer rates, the Company agreed to expense \$165,000 of the relocation expenses previously deferred in 2004. This amount has been included in other income deductions in the 2005 statement of income. In addition, \$242,000 of the amounts deferred in 2004 were returned to rate base and reclassified to plant property and equipment, effective January 1, 2005.

10. Interest

As directed by the Commission, the Company has an interest deferral mechanism that mitigates exposure to fluctuations in floating interest rates on both short term and long term debt instruments.

11. Gas purchase variance payable

Gas purchase variance payable amounts arise due to unanticipated commodity cost and demand fluctuations between actual natural gas costs and forecast natural gas costs as recovered in rates. As directed by the Commission, gas purchase variance payable amounts are being refunded to customers on a straight-line basis generally over one year of forecast deliveries. The amount of such credits included in cost of sales in 2006 was \$2,096,000 before income taxes (2005 - \$2,466,000; 2004 - \$2,319,000).

OTHER ITEMS AFFECTED BY RATE REGULATION

Future income taxes

The Company recovers tax expense based on the taxes payable method, as prescribed by the Commission, for rate-setting purposes. Under the income taxes currently payable method, no provisions are made for future or deferred income taxes as a result of differences in timing between the treatment for income tax and accounting purposes of the various income and expenditure items. Therefore, rates do not include the recovery of future income taxes related to temporary differences. Consequently, the Company does not record future income taxes for its regulated activities as the Company expects that all future income taxes will be recovered in rates when they become payable. Generally accepted accounting principles require the recognition of future income tax liabilities and future income tax assets in the absence of rate regulation.

Deferred income tax expenses shown on the consolidated statements of income arise from temporary differences related to the regulatory deferral accounts identified above. The regulatory deferral accounts are recorded on the balance sheet at December 31, 2006 net of deferred income tax assets of \$5.4 million (2005 - liabilities of \$2.0 million). In the absence of rate regulated accounting, regulatory deferrals would not be recorded nor would the associated deferred or future income tax liabilities or assets. However, future income taxes associated with certain assets, primarily property, plant and equipment, would be recorded, in the absence of rate regulated accounting, resulting in the recognition of \$21.0 million (2005 - \$20.2 million) in future income tax liabilities. As a result of these impacts, earnings would decrease by \$0.8 million in the year ended December 31, 2006 (2005 - increase by \$1.1 million).

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

	2006	2005
(\$ in thousands)		
Deferred income tax liabilities, as reported	15,430	15,430
Adjustment to reflect liability method	(4,901)	(5,246)
Unrecorded future income tax liabilities, beginning of year	9,998	10,633
Unrecorded future income tax expense (recovery)	447	(635)
Future income tax liability, end of year	20,974	20,182

Allowance for funds used during construction (AFUDC) and other capitalized costs

AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and a cost of equity component, as approved by the Commission. In the absence of rate regulation, generally accepted accounting principles would permit the capitalization of only the interest component. Therefore, the recording of the equity component as a capitalized asset and the corresponding earnings recognized during the construction phase would not be recognized nor would the subsequent depreciation of the capitalized equity component. It is not possible to make a reasonable estimate of the carrying value of the equity component of AFUDC included in property, plant and equipment. In 2006, the Company capitalized AFUDC amounting to \$11,000 (2005 - \$258,000; 2004 - \$47,000).

As directed by its regulator, when a fixed asset is retired or otherwise disposed of, the Company does not reflect a gain or loss in income. Entities not subject to rate regulation write off the net book value of the retired asset and include any resulting gain or loss in current operating results. Since the Company does not calculate depreciation expense for individual assets, it cannot identify or quantify gains or losses on the retirement of a fixed asset in any given year which would have been recorded had the Company not been subject to rate regulation.

Interest capitalization

The Company is permitted to earn a short term interest return on deferrals excluded from rate base. For the years 2004 through 2006, interest was capitalized at 6 percent on all regulatory deferrals excluded from rate base. In the absence of rate regulation, generally accepted accounting principles would not permit the capitalization of interest on deferrals. Therefore, the recording of the interest component as a deferred asset or liability and the corresponding earnings adjustment would not be recognized nor would the subsequent amortization of the capitalized interest component. In 2006, this resulted in a charge to income of \$605,000 (2005 - charge of \$175,000; 2004 - charge of \$135,000).

Overhead capitalization

With the approval of the Commission, the Company capitalizes a percentage of certain operating, administrative and general costs into the rate base on an ongoing basis. Such treatment is accorded in recognition of the significance of plant, property and equipment constructed by the Company. The Company is authorized to charge depreciation and earn a rate of return on the net book value of such capitalized costs in future years. In the absence of rate regulated accounting, such overhead costs would be charged to the consolidated statement of earnings in the period in which they occurred. In 2006, the Company capitalized \$1.69 million of overhead costs to plant, property and equipment (2005 - \$1.42 million; 2004 - \$1.53 million).

Non-pension post retirement benefits

The Company provides for post-retirement benefits other than pensions. The cost of providing these benefits are expensed when paid. In addition, since 2004 the Company has expensed the current service cost relating to benefits earned by employees in the current year. Under generally accepted accounting principles, the Company would also expense the annual interest cost and amortize any actuarial gains and losses into income. Had these costs been accrued and their recovery not permitted in customers' rates, earnings in 2006 would have decreased by \$272,000 (2005 - \$221,000; 2004 - \$315,000) (see note 6).

Derivative instruments and hedging

To be recorded as a hedging instrument under GAAP for non rate-regulated entities, a derivative instrument has to be designated as such and be effective. If a derivative instrument does not meet either the designation criterion or the effectiveness criterion, it is recorded at its fair value and any resulting realized or unrealized gains and losses are included in income. In the absence of rate regulation, the Company would have had to choose whether to adopt hedge accounting as outlined in CICA Handbook Section 3865, "Hedges" and its predecessor, Accounting Guideline 13, "Hedging Relationships" and ensure its documentation and effectiveness testing met the specified criteria. Since the accounting for these derivative instruments is determined by rate regulation, the Company chose not to make the required designations nor ensure it meets all of the documentation and other criteria required to treat these instruments as hedging transactions under GAAP.

3 MAJOR CUSTOMERS

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

	2006		2005		2004	
	ENERGY	OPERATING REVENUES	ENERGY	OPERATING REVENUES	ENERGY	OPERATING REVENUES
(Percent)						
Methanex Corporation	-	5	62	7	67	9
West Fraser Mills Ltd., Alcan Inc. and British Columbia Hydro and Power Authority	24	6	9	5	8	6

At December 31, 2006, 4% (2005 - 7%; 2004 - 9%) 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.

On August 30, 2005, Methanex Corporation gave notice of termination of its Firm and Interruptible Gas Transportation Service Agreement with

the Company. Under the terms of the agreement, Methanex made a termination payment to the Company of approximately \$233 million on February 28, 2006, the effective date of the termination. As approved by the British Columbia Utilities Commission, the termination payment has been recorded, net of income taxes of \$796 million, as an interest bearing credit deferral, and will be amortized into income over the period from March 1, 2006 to October 31, 2009. Approximately \$5.6 million of the termination payment has been amortized in 2006 and is included in other operating revenues.

4 PLANT, PROPERTY AND EQUIPMENT

AS AT DECEMBER 31, 2006	AVERAGE	COST	ACCUMULATED	NET BOOK
	DEPRECIATION		DEPRECIATION	VALUE
(\$ in thousands)	RATE (PERCENT)			
Transmission plant	2.7	176,689	73,307	103,382
Distribution plant	2.6	87,920	32,591	55,329
General plant	4.2	20,729	7,617	13,112
Processing plant	5.9	806	226	580
Construction in progress	-	593	-	593
	2.8	286,737	113,741	172,996

AS AT DECEMBER 31, 2005	AVERAGE	COST	ACCUMULATED	NET BOOK
	DEPRECIATION		DEPRECIATION	VALUE
(\$ in thousands)	RATE (PERCENT)			
Transmission plant	2.8	172,212	68,618	103,594
Distribution plant	2.6	86,200	30,784	55,416
General plant	4.3	21,146	9,394	11,752
Processing plant	4.9	745	458	287
Construction in progress	-	302	-	302
	2.8	280,605	109,254	171,351

During the year, the Company received contributions in aid of construction of \$233,000 (2005 - \$278,000; 2004 - \$257,000), which have been recorded as a reduction of distribution plant.

The following table provides information on the changes in the balance of plant, property and equipment cost:

	2006	2005
(\$ in thousands)		
Cost, beginning of year	280,605	291,141
Capital expenditures, net of contributions in aid of construction	8,211	6,847
Depreciation capitalized	217	191
Plant retirements	(2,296)	(2,235)
Deactivated assets (note 2)	-	(15,581)
Cost transferred from (to) deferred charges (note 2)	-	242
Cost, end of year	286,737	280,605

The following table provides information on the changes in the balance of accumulated depreciation:

	2006	2005
(\$ in thousands)		
Accumulated depreciation, beginning of year	109,254	114,361
Depreciation expense	7,687	8,011
Depreciation capitalized	217	191
Plant retirements	(2,296)	(2,235)
Salvage on plant retirements	118	94
Deactivated assets (note 2)	-	(10,531)
Depreciation adjustments for prior year retirements (note 2)	(1,239)	(637)
Accumulated depreciation, end of year	113,741	109,254

5 INCOME TAXES

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

	2006	2005
(\$ in thousands)		
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	15,430	15,430

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:

	2006	2005	2004
(Percent)			
Combined Canadian federal and provincial statutory income tax rates, including surtaxes	34.1	34.9	35.6
Increase (decrease) in income taxes resulting from:			
Large corporations tax	-	2.2	3.1
Depreciation in excess of capital cost allowance	5.2	5.4	7.0
Amortization of intangibles	3.3	2.5	2.7
Deferred charge expenditures	(3.0)	-	-
Capitalized overhead deducted for tax purposes	(6.6)	(3.8)	(4.9)
Imputed interest on deferred charges and credits	2.6	0.5	0.5
Other items	1.7	(2.0)	(0.8)
Effective rate of income taxes	37.3	39.7	43.2

6 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. Benefits earned under the defined benefit plans are principally based on years of service and average earnings.

6 EMPLOYEE FUTURE BENEFIT PLANS (CONT'D)

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:

	2006	2005
Measurement date of the plan assets and accrued benefit obligation	September 30, 2006	September 30, 2005
Effective date of the most recent actuarial valuation report for funding purposes	December 31, 2003	December 31, 2003
Effective date of the next required actuarial valuation report for funding purposes	December 31, 2006	December 31, 2006

(a) Information about the defined benefit pension plans is as follows:

	2006	2005	2004
(\$ in thousands)			
Accrued benefit obligations			
Balance, beginning of year	22,577	19,235	17,224
Current service cost	830	682	595
Employees' contributions	9	7	8
Interest cost	1,186	1,148	1,028
Benefits paid	(804)	(889)	(777)
Actuarial losses (gains)	(8)	2,394	1,157
Balance, as at measurement date	23,790	22,577	19,235
Plan assets			
Fair value, beginning of year	16,106	14,038	12,720
Actual return on plan assets	1,142	1,785	1,590
Employer contributions	1,089	1,165	497
Employees' contributions	9	7	8
Benefits paid	(804)	(889)	(777)
Fair value, as at measurement date	17,542	16,106	14,038
Funded status – plan deficit	(6,248)	(6,471)	(5,197)
Unamortized net actuarial losses	5,777	6,216	4,749
Unamortized transitional asset	(30)	(28)	(26)
Accrued benefit obligation as at measurement date	(501)	(283)	(474)
Employer contribution between measurement date and year end	248	374	593
Accrued benefit assets (liability) end of year	(253)	91	119

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

	2006	2005	2004
(Percent)			
Accrued benefit obligation as of December 31, with a measurement date of September 30:			
Discount rate	5.25	5.25	6.00
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	6.00	6.00
Expected long term rate of return on plan assets	7.50	7.50	7.50
Rate of compensation increase	3.25	3.25	3.25

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

	2006	2005
(Percent)		
Asset category:		
Equity securities	58	59
Debt securities	37	35
Real estate	–	–
Other	5	6
	100	100

The Company's pension plan expense is as follows:

	2006	2005	2004
(\$ in thousands)			
Current service cost	830	682	595
Interest cost	1,186	1,148	1,028
Expected return on plan assets	(1,113)	(1,069)	(930)
Amortization of past service costs	–	–	1
Amortization of net actuarial loss	402	211	214
Amortization of transitional asset	2	2	2
Net defined benefit pension plan expense	1,307	974	910
Defined contribution pension plan expense	65	58	46
Total pension expense	1,372	1,032	956

(b) The following is a summary of the significant actuarial assumptions used in measuring the Company's accrued non-pension post retirement benefit obligations:

	2006	2005	2004
(percent)			
Accrued benefit obligation as of December 31, with a measurement date of September 30:			
Discount rate	5.25	5.25	6.00
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	6.00	6.00
Expected long term rate of return on plan assets	3.75	7.50	7.50
Rate of compensation increase	3.25	3.25	3.25

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

	2006	2005	2004
(\$ in thousands)			
Accrued benefit obligations			
Balance, beginning of year	5,083	4,162	4,739
Current service cost	165	115	180
Interest cost	266	247	284
Benefits paid	(211)	(199)	(192)
Actuarial loss (gain)	18	758	(849)
Balance, as at measurement date	5,321	5,083	4,162
Plan assets			
Fair value, beginning of year	-	-	-
Employer contributions	633	199	192
Benefits paid	(211)	(199)	(192)
Fair value, as at measurement date	422	-	-
Funded status – plan deficit	(4,899)	(5,083)	(4,162)
Unamortized net actuarial losses	4,860	4,788	3,982
Accrued benefit obligation as at measurement date	(39)	(295)	(180)
Employer contribution between measurement date and year end	41	295	-
Accrued benefit assets (liability) end of year	2	-	(180)

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. Commencing in 2005, the amounts expensed in 2004, 2005 and 2006 have been funded through contributions to a retirement compensation arrangement, as directed by the Commission.

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:

	2006	2005	2004
(\$ in thousands)			
Current service cost	165	115	180
Benefits paid	211	199	192
Non-pension post-retirement benefit expense, as reported	376	314	372
Interest cost	266	247	284
Expected return on plan assets	(8)	-	-
Amortization of transitional obligation	123	123	123
Amortization of net actuarial loss	94	50	100
Less benefits paid, expensed above	(211)	(199)	(192)
Non-pension post-retirement benefit plan expense, accrual method	640	535	687

Total cash payments for employee future benefits are \$1,518,000 in 2006 (2005 - \$1,489,000; 2004 - \$1,153,000), 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 and non-pension post retirement benefit plans.

7 BANK INDEBTEDNESS

	2006	2005
(\$ in thousands)		
Bank overdraft	5,075	10,159
Bank demand operating line of credit	-	-
Bank indebtedness	5,075	10,159

7 BANK INDEBTEDNESS (CONT'D)

The Company has lines of credit that provide for a bank operating facility and hedge line of credit totalling \$35 million (2005 - \$35 million; 2004 - \$25 million). The lines of credit have a term of 18 months, expiring July 22, 2007. The amount available under the operating facility is subject to borrowing base requirements. The lines of credit are collateralized by the pledge of a \$40 million debenture and a charge on certain accounts receivable and inventories. The operating facility bears interest at prime rate or bankers' acceptance rates (December 31, 2006 - 6.0%; December 31, 2005 - 5.0%) and provides funds for working capital requirements. At December 31, 2006, the amount available under the facility was \$20 million, \$6.9 million of which had been utilized.

8 LONG TERM DEBT

	2006	2005
(\$ in thousands)		
Secured Debentures (a)		
RoyNat Debenture due January 15, 2011, bearing interest at a floating rate (December 31, 2006 - 7.338%), payable in monthly instalments of \$110,000, with a final instalment of \$120,000 at maturity.	5,400	6,720
RoyNat Debenture due December 15, 2012, bearing interest at a floating rate (December 31, 2006 - 7.838%), payable in monthly instalments of \$105,000, with a final instalment of \$2,505,000 at maturity.	9,960	11,220
2011 Series Debenture, 10.75% due December 13, 2011, payable in annual instalments of \$700,050 and \$799,500 in each of years 2009 and 2010 with a final instalment of \$4,999,500 at maturity.	7,999	8,700
2018 Series Debenture, 8.75% due November 15, 2018, payable in annual instalments of \$600,000 and \$1,000,000 in each of the years 2014 to 2017, with a final instalment of \$7,000,000 at maturity.	15,200	15,800
2025 Series Debenture, 9.30% due July 18, 2025, payable in annual instalments of \$500,000 with a final instalment of \$9,500,000 at maturity.	18,500	19,000
2027 Series Debenture, 6.90% due December 2, 2027, payable in annual instalments of \$500,000 with a final instalment of \$9,500,000 at maturity.	19,500	20,000
	76,559	81,440
Long term debt due within one year (b)	4,880	4,880
	71,679	76,560

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

(\$ in thousands)	
2007	4,880
2008	4,880
2009	4,980
2010	4,980
2011	7,980
Thereafter	48,859
	76,559

9 PREFERRED SHARES

	2006	2005
(\$ in thousands)		
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.

10 COMMON SHARES AND CONTRIBUTED SURPLUS

	2006	2005
(\$ in thousands)		
Authorized		
6,020,000	Voting common shares with a par value of \$2.50 each	
Issued		
3,641,180	9,103	9,065
	Common shares (2005 - 3,626,180)	

During 2006, the Company issued 15,000 common shares (2005 - 22,600) for cash consideration of \$199,000 (2005 - \$185,000) upon the exercise of employee options. Of this amount, \$161,000 (2005 - \$129,000) has been credited to contributed surplus, representing the excess of the issue price over the par value of the shares.

The following table describes the changes in contributed surplus during the year:

	2006	2005
(\$ in thousands)		
Contributed surplus, beginning of year	2,828	2,567
Excess of cash consideration over par value of common shares issued	161	129
Stock option expense	179	132
Contributed surplus, end of year	3,168	2,828

11 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 closing price of the common shares on the

Toronto Stock Exchange determined as of the trading day immediately preceding the date of the option 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, 2006, there are 347,618 (2005 - 307,980) shares reserved for issuance pursuant to options that may be granted under the stock option incentive plan.

In 2006, 47,600 options were issued at an average exercise price of \$18.84.

Since January 1, 2003, the Company has accounted 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 2006 is \$179,000 (2005 - \$132,000; 2004 - \$93,000).

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:

	2006	2005	2004
Dividend yield	4.2%	4%	4%
Expected volatility (annualized)	28.0%	29%	44%
Risk free interest rate	4.1%	3.7%	3.0%
Expected years of option life (average)	7.5	7.5	7.5

A summary of the changes to of the Company's stock option plan during the years ended December 31, 2006, 2005 and 2004 is as follows:

	2006		2005		2004	
	NUMBER OF SHARES	WEIGHTED- AVERAGE EXERCISE PRICE \$	NUMBER OF SHARES	WEIGHTED- AVERAGE EXERCISE PRICE \$	NUMBER OF SHARES	WEIGHTED- AVERAGE EXERCISE PRICE \$
Outstanding at beginning of year	267,600	16.40	278,400	15.61	272,200	14.52
Granted	47,600	18.84	31,200	19.70	25,900	20.80
Exercised	(15,000)	13.24	(22,600)	8.20	(19,700)	7.28
Forfeited	(9,100)	20.10	-	-	-	-
Expired	(13,200)	18.75	(19,400)	20.00	-	-
Outstanding at end of year	277,900	16.75	267,600	16.40	278,400	15.61
Options exercisable at end of year	208,660	16.04	206,560	15.91	212,600	15.78
Weighted average remaining contractual life	5.7 years		5.8 years		5.9 years	

11 STOCK OPTION PLAN (CONT'D)

The following table summarizes information about the stock options outstanding and exercisable as at December 31, 2006:

EXPIRY DATE	OPTIONS OUTSTANDING	OPTIONS EXERCISABLE	EXERCISE PRICE \$
March 14, 2007	12,700	12,700	20.75
March 24, 2008	11,500	11,500	30.50
March 11, 2009	13,200	13,200	24.50
March 16, 2010	22,900	22,900	15.50
March 21, 2011	18,800	18,800	7.85
April 27, 2011	11,700	11,700	6.50
March 15, 2012	28,800	28,800	13.50
July 4, 2012	30,000	30,000	13.50
March 13, 2013	30,600	24,240	14.15
March 2, 2014	23,800	14,280	20.80
August 5, 2015	28,800	11,520	19.70
March 2, 2016	33,100	6,620	18.70
October 19, 2016	12,000	2,400	19.26
	277,900	208,660	

12 JOINT VENTURES

In 2005 the Company commenced preliminary study and investigation of a project to loop its main line transmission system from Kitimat to Summit Lake (the "KSL Project"). On July 17, 2006, the Company announced the formation of Pacific Trail Pipelines Limited Partnership, an equal partnership between the Company and Galveston LNG Inc., the parent company of Kitimat LNG Inc., for the purpose of developing the KSL Project.

The following amounts represent the Company's proportionate interest in Pacific Trail Pipelines Limited Partnership and its general partner, Pacific Trail Pipelines Management Inc. at December 31, 2006:

	2006
(\$ in thousands)	
Balance Sheet	
Current assets	596
Non-current assets	–
Current liabilities	604
Non-current liabilities	–

FOR THE PERIOD JULY 14, 2006 TO DECEMBER 31, 2006

(\$ in thousands)	
Income Statement	
Revenues	–
Expenses	2,843
Net loss	2,843
Cash Flow	
Cash provided by (used in):	
Operations	(1,200)
Financing	1,641
Investing	(50)
Proportional share of increase in cash of joint venture	391

13 RELATED PARTY TRANSACTIONS

Accounts receivable at December 31, 2006 include \$7,000 due from Pacific Trail Pipelines Limited Partnership, and relate to expenditures made by the Company which are to be reimbursed by the partnership.

14 FAIR VALUES OF FINANCIAL INSTRUMENTS

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

	CARRYING VALUE		FAIR VALUE	
	2006	2005	2006	2005
(\$ in thousands)				
Short term investments	10,971	–	10,968	–
Long term debt	76,560	81,440	88,129	90,566

The fair value of the Company's short term investments and long term debt is estimated by reference to quoted market prices for 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.

15 NATURAL GAS CONTRACTS

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

The Company had outstanding fixed price contracts, natural gas swap and collar contracts, and call options relating to natural gas supply as follows:

As at December 31, 2006

FINANCIAL INSTRUMENT	NOTIONAL QUANTITY (GJ'S)	PERCENT OF ANNUAL GAS PURCHASES	DELIVERY PERIOD	PRICE RANGE (PER GJ)	ESTIMATED FAIR VALUE RECEIVABLE (PAYABLE)
					(\$ in thousands)
Fixed price contracts	450 000	4.5	Jan. - Mar. 2007	\$7.317	(542)
Natural gas swap contracts	4 308 000	43.4	Jan. 2007 - Oct. 2008	\$6.84 to \$10.28	(5,876)
Costless Collars	500 500	5.0	Jan. 2007 - Oct. 2008	Floors from \$6.05 to \$8.55; Caps from \$8.65 to \$10.65	250
Call options	174 500	1.8	Jan. - Oct. 2007	Caps from \$8.40 to \$8.99	53
Total	5 433 000	54.7			(6,115)

As at December 31, 2005

FINANCIAL INSTRUMENT	NOTIONAL QUANTITY (GJ'S)	PERCENT OF ANNUAL GAS PURCHASES	DELIVERY PERIOD	PRICE RANGE (PER GJ)	ESTIMATED FAIR VALUE RECEIVABLE (PAYABLE)
					(\$ in thousands)
Fixed price contracts	450 000	4.6	Jan. - Mar. 2006	\$10.00	(167)
Natural gas swap contracts	1 193 000	12.1	Jan. - Oct. 2006	\$7.85 to \$10.60	1,670
Call options	1 219 500	12.3	Jan.- Mar. 2006	Caps from \$10.00 to \$15.00	633
Total	2 862 500	29.0			2,136

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 Company's purchase commitments at December 31, 2006 under various gas supply contracts expiring through 2011 were as follows:

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

(\$ in thousands)	
2007	35,854
2008	4,791
2009	935
2010	67
2011	-
Thereafter	-

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 gas.

16 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.

17 SUPPLEMENTAL CASH FLOW INFORMATION

	2006	2005	2004
(\$ in thousands)			
Depreciation and amortization:			
Depreciation, per income statement	7,687	8,011	7,877
Amortization of deferred charges, per income statement	691	755	763
Amortization of debt issue costs, included in long term interest expense	116	139	160
Total depreciation and amortization	8,494	8,905	8,800
Non-cash working capital changes:			
(Increase) decrease in:			
Accounts receivable	(1,076)	(5,527)	1,796
Income taxes recoverable	375	(13)	(362)
Inventories of supplies and natural gas	85	(963)	490
Prepaid expenses	(2,534)	(1,585)	(82)
Increase (decrease) in:			
Accounts payable and accrued liabilities	973	5,075	924
Gas purchase variance payable	2,234	(1,351)	(1,047)
Income and other taxes payable	7,114	537	(11)
Attributable to operating activities	7,171	(3,827)	1,708
Interest and tax payments:			
Income taxes paid	2,680	2,790	2,993
Interest paid	6,790	7,181	7,269

18 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.

YEARS ENDED DECEMBER 31	2006	2005	2004	2003	2002
OPERATING DATA					
DELIVERIES (TJ)					
Sales					
Residential	3 066	3 135	3 279	3 464	3 503
Commercial	2 706	2 659	2 655	2 845	2 898
Small industrial	710	689	778	825	1 050
Large industrial	523	506	626	620	594
	7 005	6 989	7 338	7 754	8 045
Transportation					
Commercial	157	61	60	64	69
Small industrial	2 774	2 887	2 958	2 764	2 755
Large industrial – Methanex	3	20 497	25 952	23 820	25 552
Large industrial – other	2 456	2 410	2 663	2 236	3 042
	5 390	25 855	31 633	28 884	31 418
TOTAL DELIVERIES	12 395	32 844	38 971	36 638	39 463
Customers at year end	39,511	39,295	39,291	39,106	39,254
Degree days					
Actual	4,856	4,655	4,895	5,153	5,204
Normal	5,070	5,123	5,148	5,155	5,104
Actual as a percent of normal	96%	91%	95%	100%	102%
Degree day is a measure of coldness. It is calculated by accumulating for each day in the fiscal period the total number of degrees by which the daily mean temperature fell below 18 degrees Celsius. The figures given are the average for all service areas, weighted by deliveries.					
FINANCIAL DATA (\$ in thousands)					
REVENUE					
Sales					
Residential	44,919	42,354	37,627	38,815	30,204
Commercial	34,241	31,546	26,488	28,196	22,213
Small industrial	7,152	5,599	5,746	6,840	7,151
Large industrial	5,087	5,370	5,032	5,026	3,292
	91,399	84,869	74,893	78,877	62,860
Transportation					
Commercial	630	217	197	182	182
Small industrial	3,308	3,188	2,839	2,705	2,328
Large industrial – Methanex	1,822	12,182	12,191	12,344	20,589
Large industrial – other	2,945	2,824	3,175	5,688	3,670
	8,705	18,411	18,402	20,919	26,769
Off-system sales	32,713	56,159	43,949	33,403	18,763
Methanex termination amortization	5,552	–	–	–	–
Other	479	511	511	528	671
TOTAL REVENUES	138,848	159,950	137,755	133,727	109,063
EXPENSES					
Cost of sales	91,118	111,287	88,954	84,417	56,820
Operating	17,026	17,166	18,716	18,471	19,164
Interest	9,673	7,537	7,976	8,053	7,642
Municipal and other taxes	4,755	4,120	3,941	3,982	4,259
Depreciation and amortization	8,378	8,766	8,640	8,376	9,653
Income taxes	2,947	4,414	4,120	4,760	6,935
	133,897	153,290	132,347	128,059	104,473
NET INCOME	4,951	6,660	5,408	5,668	4,590
Net income applicable to common shares	4,614	6,323	5,071	5,331	4,253

YEARS ENDED DECEMBER 31	2006	2005	2004	2003	2002
(\$ in thousands, except for per share data)					
CASH FLOW DATA					
Operating cash flow	10,403	15,696	14,634	14,153	14,570
Additions to plant, property and equipment	(8,093)	(6,753)	(11,276)	(5,406)	(5,965)
(Increase) decrease in deferred charges	(269)	(1,799)	(1,071)	(2,519)	(372)
Issue of long term debt	-	-	-	-	15,037
Repayment of long term debt	(4,881)	(4,380)	(4,380)	(3,880)	(2,623)
Dividends paid on common shares	(2,907)	(2,898)	(2,880)	(12,719)	-
CAPITALIZATION					
Non-current liabilities	477	224	407	224	-
Methanex termination payment deferral	8,096	-	-	-	-
Long term debt	71,679	76,560	81,440	85,827	90,224
Deferred income taxes	15,430	15,430	15,430	15,430	15,453
Preferred shares	5,000	5,000	5,000	5,000	5,000
Common equity	79,777	77,692	73,950	71,522	68,966
	180,459	174,906	176,227	178,003	179,643
UTILITY PLANT					
In service (net)	172,403	171,049	172,201	173,699	176,711
Construction in progress	593	302	4,579	649	603
	172,996	171,351	176,780	174,348	177,314
COMMON SHARE TRADING (TSX)					
High	19.75	24.00	22.00	19.50	18.00
Low	16.96	17.37	17.28	14.00	9.35
Close	18.05	19.55	20.93	19.46	17.75
Volume (in shares)	1,601,034	2,150,589	929,506	709,592	809,778
PER COMMON SHARE DATA					
Earnings applicable to common shareholders	1.27	1.75	1.41	1.49	1.20
Dividends declared on common shares	0.80	0.80	0.80	0.80	2.75
FINANCIAL RATIOS					
Return on average shareholders' equity ⁽¹⁾	5.8%	8.2%	6.9%	7.5%	5.6%
Return on average capital employed ⁽²⁾	6.4%	6.2%	5.7%	5.8%	5.0%
Earnings coverage of interest ⁽³⁾	2.5	2.5	2.2	2.3	2.5
Dividend payout ratio	63.0%	45.7%	56.7%	53.7%	229.2%
(1) Net income applicable to common shareholders divided by average common equity (weighted quarterly during the year).					
(2) Sum of net income and after-tax interest expense divided by average capital employed (weighted quarterly during the year). Capital employed is equal to the sum of shareholders' equity, deferred income taxes, deferred credits, and total debt.					
(3) Earnings before interest and taxes divided by total interest.					
ALLOWED RETURN ON COMMON EQUITY:					
Western system	9.45%	9.68%	9.80%	10.17%	9.88%
Fort St. John / Dawson Creek division	9.20%	9.43%	9.55%	9.82%	9.63%
Tumbler Ridge division	9.45%	9.68%	9.80%	10.07%	9.88%

DIRECTORS

DIRECTOR SINCE

ROBERT F. CHASE ^{1,2,4} President and Chief Executive Officer Lexacal Investment Corp. West Vancouver, British Columbia	1995
ROY G. DYCE President and Chief Executive Officer Pacific Northern Gas Ltd. Coquitlam, British Columbia	1982
DIANE M. FULTON ^{2,5} Executive Director, Investments University of British Columbia Faculty Pension Plan Vancouver, British Columbia	2005
HUGH C. MORRIS ^{1,3} Chair Eldorado Gold Corporation Delta, British Columbia	1986
DAVID J. ROWNTREE ^{3,5} Managing Director Tricor Pacific Capital, Inc. West Vancouver, British Columbia	2003
DAVID G. UNRUH ^{3,4} Director Westcoast Energy Inc. and Union Gas Limited West Vancouver, British Columbia	2002
ARTHUR H. WILLMS ^{1,4,5} Director Westcoast Energy Inc. and Union Gas Limited Vancouver, British Columbia	1983
JANET P. WOODRUFF ² Chief Financial Officer and Vice President, Systems Development and Performance Vancouver Coastal Health West Vancouver, British Columbia	2006

¹ Executive Committee

² Audit Committee

³ Environment, Health and Safety Committee

⁴ Corporate Governance Committee

⁵ Human Resources and Compensation Committee

OFFICERS

R.F. Chase	Chair of the Board
R.G. Dyce	President and Chief Executive Officer
G.B. Weeres	Vice President, Operations and Engineering
E.A. Fletcher	Chief Financial Officer
C.P. Donohue	Director, Regulatory Affairs and Gas Supply and Assistant Secretary
K.R. Teitge	Director, Corporate Development and Treasurer
K.E. Stark-Anderson	Secretary

INVESTOR INFORMATION

Stock Exchange, Securities and Symbols

Common and preferred shares are listed on the Toronto Stock Exchange under the symbols: PNG and PNG.PRA, respectively.

Annual Meeting

The Annual Meeting of the Shareholders of Pacific Northern Gas Ltd. will be held at The Terminal City Club, President's Room, 837 West Hastings Street, Vancouver, British Columbia on April 26, 2007 at 10:30 a.m. (Pacific Daylight Time).

Annual Information Form

The Company's 2006 Annual Information Form, as filed with Canadian securities commissions, is available on our web site at www.png.ca.

Registrar and Transfer Agent

Computershare Investor Services Inc. (Vancouver, Calgary, Winnipeg, Toronto and Montreal).

Shareholder Assistance

If you are a registered shareholder and have questions regarding your account, please contact our transfer agent in writing, by telephone, fax or email at:

Computershare Investor Services Inc., 100 University Avenue, 9th Floor, Toronto, Ontario, Canada M5J 2Y1

Phone Toll-free North America 1.800.564.6253
International 514.982.7555

Fax Toll-free North America 1.866.249.7775
International 416.263.9524

Email service@computershare.com

Internet www.computershare.com – the Investors section offers enrolment for self-service account management for registered shareholders through *Investor Centre*.

If you hold your shares in a brokerage account (beneficial shareholder), questions should be directed to your broker on all administrative matters.

The Company's corporate and financial information, including quarterly reports, news releases, and utilities regulatory applications, is available on our website at www.png.ca.

Corporate Governance

Please refer to the Company's Notice of 2007 Annual Meeting of Shareholders and Management Information Circular for the Company's report on corporate governance. The Audit Committee of the Board of Directors has established an anonymous and confidential toll-free telephone number and web-based reporting tool for employees, contractors and others to call with respect to accounting irregularities and ethical violations. The telephone number is 1.800.661.9675 and the web address is www.png-eweb.com.

Additional information relating to the Company is filed with securities regulators at www.sedar.com.

PACIFIC NORTHERN GAS LTD.

Head Office

Suite 950, 1185 West Georgia Street,
Vancouver, BC, Canada V6E 4E6
T 604 691 5680 F 604 697 6210

www.png.ca

Principal Field Operating Office

2900 Kerr Street, Terrace, BC, Canada V8G 4L9

