

Management's Discussion and Analysis

Pacific Northern Gas Ltd.

December 31, 2006



PACIFIC NORTHERN GAS LTD.
MANAGEMENT'S DISCUSSION AND ANALYSIS
DECEMBER 31, 2006

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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 interconnection 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.

[Dollar amounts in thousands, except per share and per GJ figures]

	2006	2005	2004
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
Transportation service – 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 7.6 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.

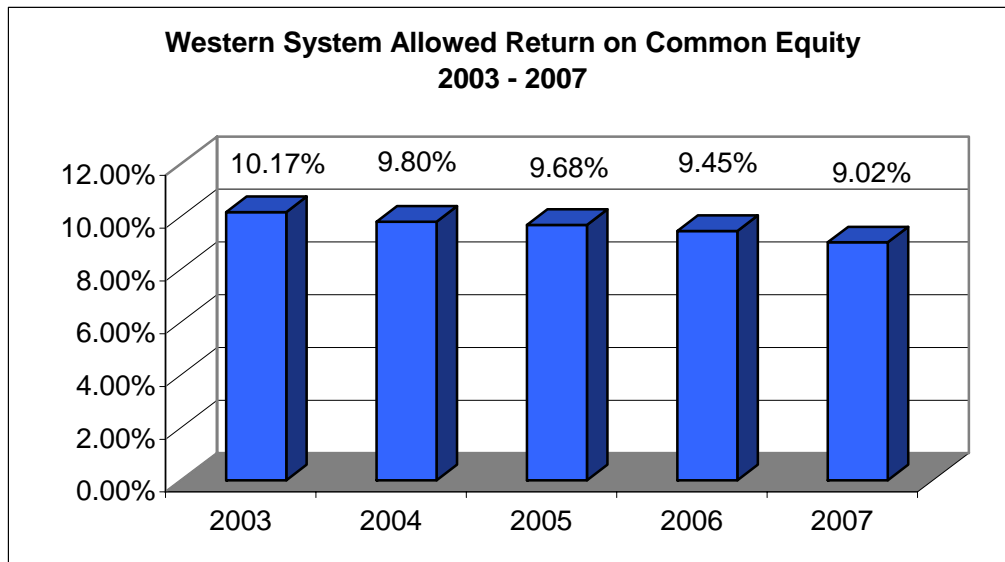
The 2007 revenue requirements application for the Western system was filed with the Commission in October 2006. The application sought approval of an increase in delivery charges of 1.7 percent. The Commission approved interim gas delivery charge increases effective January 1, 2007 at the level set forth 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 7.1 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.



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 7.9 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.

[\$ in thousands, except for per share data]

	2006			
	Mar. 31	June 30	Sept. 30	Dec. 31
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 \$7.5 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

[<i>\$ in thousands</i>]	Payments Due by Period as of December 31, 2006				
	Total	Less than 1 year	1 - 3 years	4 - 5 years	After 5 years
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

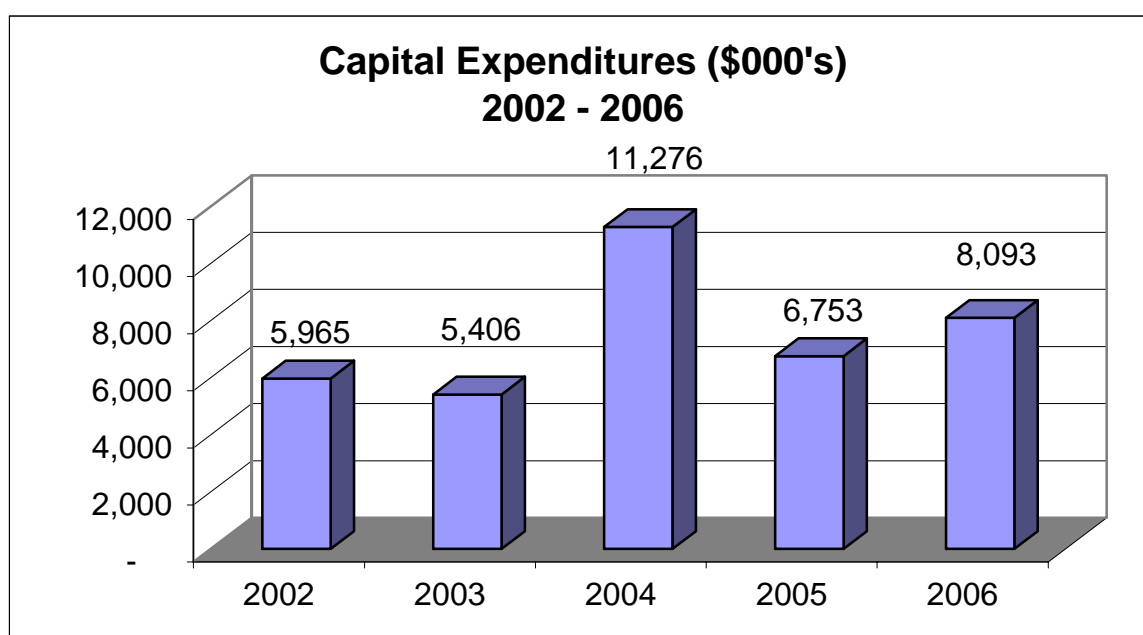
[Dollar amounts in thousands, except percent figures]

	2006	2005	2004
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

[\$ amounts in thousands]

	2006	2005	2004
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	At December 31, 2005	At December 31, 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:

[\$ amounts in thousands, except per share and per GJ figures]

	Q4 2006	Q4 2005	Percent Change
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 5.5 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) (\$000's)
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) (\$000's)
Fixed price contracts	450 000	4.6	Jan. to Mar. 2006	\$10.00	(\$167)
Natural gas swap contracts	1 193 000	12.1	Jan. to Oct. 2006	\$7.85 to \$10.60	\$1,670
Call options	1 219 500	12.3	Jan. to 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.