



Interim Statement

For the Three and Nine Months Ended September 30, 2009

October 29, 2009

Pacific Northern Gas Ltd.
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Pacific Northern Gas Ltd.

MANAGEMENT'S DISCUSSION AND ANALYSIS

for the Three and Nine Months Ended September 30, 2009

Dated October 29, 2009

Forward-Looking Statements

This Management's Discussion and Analysis ("MD&A") includes forward-looking statements. Forward-looking statements relate to, among other things, anticipated financial performance, business prospects, strategies, regulatory developments, new services, market forces, commitments and technological developments. Many of these statements can be identified by words such as "believe", "expects", "expected", "will", "intends", "projects", "anticipates", "estimates", "continues" or similar words. Pacific Northern Gas Ltd. ("the Company") believes the expectations reflected in such statements are reasonable but no assurance is given that such expectations will be correct. All forward-looking statements are based on management's beliefs and assumptions based on information available at the time the assumption was made and on its experience and perception of historical trends, current conditions and expected further developments as well as other factors deemed appropriate in the circumstances. In addition to other assumptions made in this MD&A, assumptions have been made in respect of:

- gas commodity prices;
- forecasted gas deliveries;
- regulatory conditions, including decisions by the British Columbia Utilities Commission (the "Commission");
- the Company's ability to access capital;
- capital expenditure estimates, plans, schedules and activities and the development, construction, operations and cost of facilities and infrastructure;
- income tax considerations;
- operating risks and related insurance coverage and inspection and integrity systems; and
- competitive conditions.

By its nature, such forward-looking information is subject to various risks and uncertainties that are known and unknown, including those material risks discussed in this MD&A and in the Company's 2009 Annual Information Form under "Risk Factors" which could cause the Company's actual results and experience to differ materially from the anticipated results or other expectations expressed. Such risks and uncertainties include but are not limited to: general economic conditions and markets; gas supply and availability; gas commodity price volatility; competition; decisions by regulators; seasonal weather patterns; federal and provincial climate change initiatives; financing of investments as well as the value of such investments; the cost and availability of capital; the impact on the Company's liquidity if it were to go offside of the covenants in its debt facilities; successful execution of strategic initiatives; the ability of the Company to attract and retain quality employees; and the impact of accounting changes, including the transition to International Financial Reporting Standards. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this MD&A or otherwise, and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by applicable securities laws.

Non-GAAP Measures

References to "operating margin" are to operating revenues less cost of gas. Operating margin is not a recognized measure under Generally Accepted Accounting Principles ("GAAP") and does not have

a standardized meaning prescribed by GAAP. Therefore, operating margin may not be comparable to similar measures presented by other issuers. Readers are cautioned that operating margin should not replace revenues as a measure of performance. Management believes operating margin is a meaningful measure of performance because the Company's financial results are best measured by excluding the cost of gas which is flowed through to customer rates without a mark-up.

Business of the Company

Capital Structure and Equity Risk Premium Application (the "CAP/ROE Application")

For many years the Company has maintained higher actual common equity than the Commission has allowed for rate making purposes in order to maintain a reasonable minimum level of financial integrity. As a result, the Company's actual rate of return on common equity has been less than the rate of return on common equity approved by the Commission. To address the foregoing and allow the Company the opportunity to earn a fair and reasonable return on its utility investments and achieve improved financial health, on July 16, 2009 the Company and its wholly owned subsidiary, Pacific Northern Gas (N.E.) Ltd. ("PNG(N.E.)"), jointly filed the CAP/ROE Application with the Commission to:

1. Increase the Company's deemed common equity from 40 to 47.5 percent and to increase its risk premium relative to the benchmark utility return on equity ("ROE") by 10 basis points from 65 to 75 basis points.
2. Increase PNG(N.E.)'s deemed common equity from 36 to 42.5 percent and to increase its risk premium relative to the benchmark ROE by 35 basis points from 40 to 75 basis points for the Fort St. John/Dawson Creek division and from 65 to 75 basis points for the Tumbler Ridge division.
3. Record in a return on equity deferral account the difference between the approved 2009 cost of service for the Company and the cost of service determined for 2009 on the basis of the applied for increases in the deemed common equity and risk premium. The deferred amount would be recovered over future rates. A deferral account was not requested for PNG(N.E.).
4. Recover from the \$1.5 million of option fees paid to the Company by Merrill Lynch Commodities Inc. ("Merrill Lynch"), approximately \$0.7 million of foregone return, to the end of 2009, on investment in gas transmission facilities deactivated in 2006 as a result of the loss of load following the closure of the Methanex methanol/ammonia plant.

The Commission is expected to set a regulatory timetable for review of the CAP/ROE Application in December 2009. The Company is recommending the Commission conduct an oral public hearing. The requested changes are reflected in the 2010 revenue requirements applications for all divisions. While the Company is confident in the merits of its application as filed, it can give no assurances that the applied for capital structure and equity risk premium increases from current levels will be approved by the Commission.

Filing of 2010 Revenue Requirements Applications

In early October 2009, the Company filed its 2010 revenue requirements applications for both its PNG-West and PNG(N.E.) divisions. The applications seek approval to increase rates on an interim basis effective January 1, 2010 pending the Commission's review of the CAP/ROE Application. The Western system is projecting a 2010 revenue deficiency of approximately \$7.7 million of which \$5.5 million is due to the Methanex contract termination payment credit amortization ending in October 2009. PNG(N.E.)'s Fort St. John/Dawson Creek division has a forecast revenue deficiency of close to \$0.9 million while the Tumbler Ridge division 2010 revenue deficiency is approximately \$0.1 million. The applied for delivery charge increases compared to October 2009 delivery rates for an average residential customer in each service area are 28.5 percent for the Western system (\$213 per year), 8.9 percent for the Fort St. John/Dawson Creek division (\$32 per year) and 7.8 percent for the Tumbler Ridge division (\$37 per year). However, compared to rates effective January 2009,

when gas supply recovery rates were much higher than current rates, the annual bill increase for a typical residential customer in the Western system is only \$66 per year. The Fort St. John/Dawson Creek and Tumbler Ridge average residential customer annual bills in 2010 are projected to be lower by \$240 and \$213, respectively, compared to annual bills based on January 2009 rates.

KSL Project

The Company continues to pursue a project to loop its mainline transmission system from Kitimat to Summit Lake (the "KSL Project") through its 50 percent ownership of Pacific Trail Pipelines Limited Partnership ("PTP"). The KSL Project would provide gas transportation services for up to 1.0 billion cubic feet per day, primarily for Kitimat LNG Inc.'s proposed liquefied natural gas ("LNG") export terminal ("Terminal") to be located approximately 15 kilometers southwest of Kitimat. The KSL Project entails the construction of approximately 470 kilometers of up to 36 inch diameter pipeline and associated compression facilities, at a cost of \$1.2 billion based on estimates made in 2006.

On April 8, 2009 the Province announced an agreement with 15 of the 16 First Nations' bands whose traditional territories would be traversed by the KSL Project. Under the agreement, the Province will provide the First Nations with \$3 million as an incentive for ratification of the KSL Project and a further \$32 million to acquire an equity position in PTP. PTP is negotiating agreements with the First Nations that will set out the terms and conditions under which the First Nations will have the option to invest in PTP and to realize certain other benefits from the KSL Project.

In the third quarter of 2009, Kitimat LNG Inc. publicly announced the signing of memorandum of understandings ("MOUs") with EOG Resources Canada and Apache Corporation to supply natural gas feedstock to the Terminal. Kitimat LNG Inc. also announced the signing an MOU in the third quarter with Gas Natural SDG, S.A. ("Gas Natural"), a Spanish based natural gas company, under which Gas Natural would purchase LNG produced at the Terminal. These MOUs supplemented an MOU signed with Korea Gas Corporation in the second quarter of 2009 for the purchase of LNG produced at the Terminal. PTP has not signed any agreements with respect to utilization of its planned gas transportation capacity.

Subject to a number of conditions, construction of the KSL Project by PTP is planned to commence in 2011 for completion in 2014 when the Terminal is planned to begin operation. Conditions to construction include the securing of contracts for use of PTP's transportation capacity, financing for construction of the KSL Project, and additional regulatory approvals for the KSL Project, including a Certificate of Public Convenience and Necessity from the Commission and other permits from the B.C. Oil and Gas Commission. The Company can give no assurances that these conditions will be satisfied or that construction of the KSL Project by PTP will proceed.

Capacity on the Western System

PNG filed an application with the Commission on March 12, 2009 for approval of a Letter Agreement with Merrill Lynch. The Letter Agreement provides Merrill Lynch with an option to contract for 75 MMcf per day of firm gas transportation service using existing capacity on PNG's Western pipeline system. If Merrill Lynch exercises its option, it would utilize the transportation service to deliver natural gas to a floating liquefied natural gas ("LNG") vessel to be located on the Douglas Channel near Kitimat, B.C. Merrill Lynch and Teekay Corporation have agreed to jointly develop a project to convert an existing LNG vessel into a floating LNG plant. The LNG would be transferred from the floating LNG plant to other LNG carriers for export.

The Commission approved the Letter Agreement on April 23, 2009 and a \$1.5 million option fee has been released from escrow to PNG. Merrill Lynch will have an exclusive option until December 31, 2009 to contract for firm gas transportation capacity for a 2 to 5 year primary term, with a right to renew for an additional 2 to 5 year term. Alternatively, Merrill Lynch may extend the initial option period by up to four consecutive six month periods, with payment of \$1 million for each

extension. Negotiation of a transportation service agreement is ongoing and PNG expects to file executed copies of the agreement with the Commission for acceptance as a filed tariff before the end of November 2009. The transportation service agreement would become effective following exercise of the option. However, in the unexpected event that the Commission does not accept the transportation service agreement, PNG would be required to refund the option fee to Merrill Lynch.

If the transportation service agreement comes into effect, PNG's Western pipeline system would be at full capacity utilization, generating approximately \$15 million per year of incremental revenue for the benefit of PNG and its customers. The cost to reactivate the facilities left idle when Methanex Corporation ceased operations in 2005 will be recovered from these incremental revenues. The reactivation costs are in the range of \$1.3 million with the largest single expense being the cost of completing a compressor overhaul at an estimated cost of \$0.5 million. The Company anticipates expensing all reactivation costs in the first year of operation. The commencement date for the transportation service is targeted for between January 1, 2012 and January 1, 2013. If service commences by January 1, 2012 all of the option fees previously paid by Merrill Lynch to the Company will be credited to transportation service fees payable in 2012. The option fee credit to Merrill Lynch will be reduced by \$0.5 million if service commences after January 1, 2012 but before July 1, 2012. A further reduction of \$0.5 million will apply if service commences after July 1, 2012. If service does not commence by January 1, 2013 then the transportation service agreement would terminate.

The Company can give no assurances that Merrill Lynch will extend the initial option or exercise its option to take capacity on the Western system.

Competitiveness of Rates

As a distributor of natural gas, the Company continuously monitors the competitiveness of its natural gas retail rates relative to alternative heating sources in its service area. The Company's current residential rates in all divisions are lower than the comparable residential electricity rate that became effective April 1, 2009. Recent declines in gas commodity prices payable by the Company are helping to make gas rates more competitive relative to electricity. The Province of British Columbia's (the "Province") Energy Plan, released in early 2007, calls for the Province to become self-sufficient in electricity by 2016 with all new generation capacity being carbon neutral and to use demand side management to curtail growing electricity consumption. These policy objectives have resulted in higher electricity rates. The Province implemented a carbon tax on fossil fuel consumption effective July 1, 2008. The carbon tax on natural gas was just under \$0.50 per Gigajoule ("GJ") effective July 1, 2008, rising annually by approximately \$0.25 per GJ to just under \$1.50 per GJ effective July 1, 2012. The Company's gas rates are maintaining their relative competitiveness with electricity rates as electricity rate increases have been higher than the impact of the carbon tax on natural gas prices.

Amendments made to the Utilities Commission Act (British Columbia) in 2008 focus on the energy conservation and demand side management goals and objectives set forth in the Energy Plan. PNG is participating with government stakeholder groups to keep apprised of potential cost effective demand side management initiatives that make sense for its customers.

Closure of West Fraser Eurocan Paper Mill

On October 28th, 2009, West Fraser Timber Co. Ltd., announced the permanent closure of its Eurocan paper mill in Kitimat, BC expected to take place on January 31, 2010. PNG has a transportation service agreement with West Fraser which specifies a daily contract demand volume of 6.8 MMcf per day that expires on December 31, 2013. Under the terms of its transportation agreement, West Fraser pays PNG an annual demand charge of approximately of \$2.1 million and is entitled to cancel its obligations by providing PNG with a termination payment that would recover almost 80 percent of the lost revenues under the remaining term of the agreement.

PNG expects that the termination payment would be given the same regulatory treatment as the Methanex termination payment and would be amortized over the remaining life of the agreement. In addition, as was the case with the closure of the Methanex plant, lost future revenues from the West Fraser contract are expected to be recoverable through standard rate applications to the Commission. If this is the case, PNG's anticipates limited impact on future earnings.

PNG will endeavour to replace the lost revenues through transactions similar to the agreement with Merrill Lynch to contract for the Company's excess pipeline capacity. The Company expects that the majority of revenues generated in new transactions of this nature will flow to the benefit of customers in the form of rate reductions. However, even if the lost revenues are not recovered from market transactions, management believes that, with continuing low commodity costs, PNG's delivered gas costs to customers should remain competitive with and in fact lower than electricity prices.

Overall Performance

Net loss for the three months ended September 30, 2009 was \$1.66 million, compared with a net loss of \$1.53 million for the corresponding period in 2008. After providing for preferred share dividends, the loss per common share in the three months ended September 30, 2009 was \$0.49 compared with a loss per common share of \$0.44 for the same period in 2008.

The net loss for the quarter was higher in 2009 compared to 2008 by \$0.13 million due mainly to the lower allowed ROE rate of 9.12 percent in 2009 compared to 9.27 percent in 2008 in the Western system and the Tumbler Ridge division of the Northeast system and the lower ROE of 8.87 percent in 2009 compared to 9.02 percent in 2008 in the Fort St. John/Dawson Creek division of the Northeast system. In addition, the Company had a lower number of residential customer additions compared to the 2009 anticipated additions, and lower than anticipated deliveries to large commercial customers and small industrial customers in the Western system.

Included in the net loss for the three month periods ended September 30, 2009 and 2008 are charges, net of income taxes, of \$16,000 and \$84,000, respectively for the Company's share of KSL Project development expenditures incurred by PTP. The Company's share of planned development expenditures for the KSL Project in the next three months of 2009 is \$75,000 before income taxes (\$0.01 per share, net of income taxes). 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.

Net income for the nine months ended September 30, 2009 was \$3.1 million, compared to \$2.8 million for the corresponding period in 2008. After providing for preferred share dividends, earnings per common share in the nine months ended September 30, 2009 were \$0.79 compared to \$0.69 for the same period in 2008. Net income for the nine months ended September 30, 2009 was higher by \$0.3 million compared to 2008 due mainly to lower KSL Project development expenditures incurred by PTP in 2009 and higher than anticipated deliveries to small industrial customers on a year to date basis, partially offset by the lower ROE rates in 2009 compared to 2008. Included in net income for the nine months ended September 30, 2009 and 2008 are charges, net of income taxes of \$0.1 million and \$0.4 million, respectively for the Company's share of KSL Project development expenditures. The increase in earnings per share also reflects the reduced number of common shares outstanding over the period due to the 122,416 shares purchased and cancelled by the Company under its normal course issuer bid.

The rate stabilization adjustment mechanism approved by the Commission continues to contribute to the stability of the Company's earnings. This mechanism allows the Company to record the after-tax revenue variances arising from differences between actual and forecast sales volumes for residential and small commercial customers in a deferral account for collection or refund in future rates. As a result of this account, the Company's net income was increased by \$0.1 million for the three month period ended September 30, 2009 and decreased by \$0.3 million for the nine months ended September 30, 2009.

Residential deliveries were at similar levels in the three month period ended September 30, 2009 compared to the same period in 2008 and slightly lower by 0.4 percent in the nine months ended September 30, 2009 compared to deliveries over the same period in 2008. Total commercial deliveries were lower by 6 percent and higher by 1 percent in the three month and nine month periods ended September 30, 2009, respectively, relative to deliveries over the same periods in 2008. Management believes that weather was a factor in the change in commercial deliveries as the weather was approximately 4 percent warmer in degree days in the three month period ended September 30, 2009, and weather was approximately 2 percent colder for the nine months ended September 30, 2009 compared to the same periods in 2008. There was little change in residential deliveries even though the weather was warmer during the three month period ended September 30, 2009 as consumption levels for residential customers are very low during these summer months and there is a minimal level of natural gas that is consumed by each household.

Total industrial deliveries were lower by 9 percent and 7 percent for the three month and nine month periods ended September 30, 2009, respectively, compared to the same periods in 2008 primarily due to lower deliveries to large industrial customers. Specifically, deliveries to large industrial customers were lower by 13 percent and by 18 percent for the three and nine month period ended September 30, 2009, respectively, compared to the same period in 2008, mainly due to lower deliveries to West Fraser Mills Ltd. as the company underwent a planned maintenance shutdown during 2009. Deliveries to small industrial customers were lower by 5 percent and higher by 4 percent for the three and nine month periods ended September 30, 2009, respectively, compared to the same periods in 2008 reflecting lower deliveries to customers during the summer months of 2009 due to some companies scheduling planned shutdowns during this time and higher year to date deliveries mainly due to consumption by a new customer in the Fort St. John service area. Deferral accounts are in place that recover or refund margin differences resulting from deliveries to large industrial customers and to some small industrial customers varying from the forecast approved for ratemaking purposes.

Results of Operations

Operating revenues in the three months ended September 30, 2009 decreased to \$10.5 million, as compared with \$13.8 million in the corresponding period in 2008. The decrease in operating revenues was primarily due to lower natural gas cost recoveries from customers in 2009 compared to 2008, a decrease of \$0.8 million in revenues from the sale of gas surplus to the needs of the Company's sales customers ("off system gas sales"), lower revenues from industrial customers compared with the corresponding period in 2008, offset by a higher cost of service in 2009. Any profit or loss realized on off system gas sales is deferred for future recovery from, or refund to, the Company's sales customers. The decrease in off system gas sales in the third quarter of 2009 reflects the impact of a decrease in the quantity of gas supply purchased on a committed basis in 2009 compared to 2008. Natural gas commodity prices, which are passed through to the Company's sales customers without mark-up, can be very volatile and result in significant variability of the Company's reported operating revenues, but do not affect net income.

Operating revenues in the first nine months of 2009 decreased to \$73.0 million as compared with \$91.7 million in the first nine months of 2008. The decrease in operating revenues was primarily due to the lower off system sales of \$9.6 million in the first nine months of 2009 compared to \$25.2 million during the corresponding period in 2008, lower natural gas commodity prices reflected in customer rates during the first nine months of 2009 compared to 2008, and lower deliveries to transportation service customers in the current economic conditions.

Operating margin in the three months ended September 30, 2009 remained unchanged at \$7.1 million compared to the same period in 2008. This was primarily the result of the higher cost of service for 2009 offset by the lower allowed ROE rates in 2009 compared to 2008.

Operating margin in the nine months ended September 30, 2009 increased slightly to \$33.0 million, as compared with \$32.4 million in the same period in 2008. The higher operating margin in the first

nine months of 2009 is primarily the result of the increase in the cost of service in 2009 compared to 2008 and higher than anticipated deliveries to small industrial customers.

Included in project development expenditures and other income deductions for the three month and nine month periods ended September 30, 2009 are the Company's pre-tax share of KSL Project development expenditures expensed by PTP amounting to \$0.02 million (2008: \$0.1 million) and \$0.1 million (2008: \$0.6 million), respectively.

The Company filed quarterly gas cost reports with the Commission in March, 2009, June 2009 and September 2009 on past and projected gas supply costs compared to gas cost recoveries from customers. Each report contained recommended decreases to the Company's gas cost recovery rates. The Commission issued orders accepting the Company's recommended decreases. On a cumulative basis to October 1, 2009, the reductions ranged from \$1.84 to \$5.24 per GJ.

Summary of Quarterly Results for Eight Quarters Ending September 30, 2009

<i>Thousands of dollars except per share amounts</i>	Sept 30, 2009	June 30, 2009	Mar. 31 2009	Dec. 31 2008	Sept 30, 2008	June 30, 2008	Mar. 31 2008	Dec. 31 2007
Operating Revenues	\$10,500	\$14,141	\$48,318	\$41,144	\$13,834	\$20,332	\$57,529	\$40,568
KSL expenditures, net of income taxes	(16)	(28)	(44)	(177)	(84)	(79)	(246)	(266)
Net income (loss) ¹	(1,660)	(400)	5,156	3,159	(1,528)	(205)	4,511	2,636
Earnings per share ²	(\$0.49)	(\$0.13)	1.39	0.84	(\$0.44)	(\$0.08)	\$1.21	\$0.70
- per share diluted ²	(\$0.49)	(\$0.13)	1.38	0.84	(\$0.44)	(\$0.08)	\$1.20	\$0.70

¹ The Company did not have any extraordinary items which impacted net income over the most recently completed eight quarters.

² Per share amounts are after provision for preferred share dividends of approximately \$84,000 per quarter.

The Company's natural gas distribution business is very seasonal, with higher sales in the colder winter months and lower sales in warmer months. Deliveries to residential and commercial customers tend to be more temperature sensitive than deliveries to industrial customers, with deliveries in the first and fourth quarters accounting for more than 75 percent of annual deliveries. Given that a substantial portion of its gas sales are used for space heating purposes, the Company earns in excess of its annual net income in the first and fourth quarters of its fiscal year and generally realizes losses in the other two quarters.

Liquidity

At September 30, 2009, the Company had credit facilities which included a \$25 million operating line, a \$20 million 5-year revolving term facility maturing on August 3, 2012 and a \$15 million risk management facility. The Company's operating line was increased by \$5 million from \$20 million to \$25 million on July 8, 2009 and its term renewed for 18 months. The operating line, which now expires January 7, 2011, is collateralized by a charge on the Company's accounts receivable and inventories. Draws on the operating line may be made by way of prime rate advances at the lender's prime rate plus 1.5 percent or by the issuance of the lender's Bankers' Acceptances which are subject to a credit spread of 3.0 percent. The operating line is also subject to borrowing base requirements and a financial covenant requiring the Company's debt leverage not to exceed 65 percent, or approximately the same level currently approved by the Commission for rate making purposes. As of September 30, 2009, the calculated borrowing base of the operating line was approximately \$6.9 million while actual utilization, which was related solely to the issuance of letters of credit, was \$3.0 million. The Company was in compliance with the financial covenant under its operating line through September 30, 2009.

The \$20 million 5-year revolving term facility available for general corporate purposes, is repayable at maturity and is secured by the pledge of a \$20 million debenture issued by the Company. Draws under the facility are made by prime rate advances or Bankers' Acceptance equivalent loans at the Canadian Deposit Offering Rate ("CDOR") plus 1.325 percent. The 5-year revolving term facility contains a financial covenant requiring the Company's debt leverage not to exceed 65 percent and, if the Company's secured debt rating is less than BBB (low) or the Company has no debt rating, the Company must maintain an interest coverage of 2.0 times or higher using earnings before interest, income taxes and expenditures on the KSL Project to a cumulative maximum of \$10 million. The Company's current interest coverage is greater than 2.0 times and its secured debt is currently rated at BBB (low).

\$6 million was outstanding under the revolving term facility at September 30, 2009 by Bankers' Acceptance equivalent loans. Additional funds available under the facility will be used for general corporate purposes including the Company's capital program and for expenditures on the KSL Project.

The Company's risk management facility allows it to hedge natural gas purchases in accordance with its annual gas contracting and gas price risk management plan and to enter into interest rate hedging transactions to a total maximum exposure of \$15 million, with exposure calculated by the facility provider using its standard methodology. The risk management facility is secured by the pledge of a \$20 million debenture issued by the Company.

Accounts receivable at September 30, 2009 were \$23.6 million lower than at December 31, 2008 due to a reduction in accounts receivable related to off system sales of \$6.6 million and lower receivables from residential and commercial customers of \$16.0 million due to the seasonal nature of natural gas deliveries.

Accounts payable and accrued liabilities at September 30, 2009 were \$14.9 million lower due to lower volumes of natural gas purchases in September 2009 compared to December 2008 and lower gas commodity prices. The gas purchase variance account has decreased from a \$4.2 million recoverable at December 31, 2008 to a \$0.5 million payable at September 30, 2009 due mainly to gas commodity charges recovered through customer rates exceeding the gas commodity costs paid by the Company by approximately \$3.9 million during the first nine months of 2009 and the change in accounting policy made to record deferral accounts on a gross basis instead of a net of tax basis. There was also an increase in the net fair value of the Company's derivative financial instruments recorded in the gas purchase variance account, which changed from a net liability position of \$5.5 million to \$5.3 million at September 30, 2009.

The Company purchases gas for resale to its gas sales customers and passes through the commodity cost of gas to those customers without mark-up. The rates charged to gas sales customers are based, in part, on projected gas supply prices. The Company's liquidity requirements can be 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.

Normal Course Issuer Bid

The Company commenced a normal course issuer bid through the facilities of the Toronto Stock Exchange on March 9, 2009. Under the approved program, the Company is permitted to purchase up to 300,000 of its own common shares over a term of one year. Subject to certain exemptions for block purchases, the Company was permitted to purchase up to 1,627 common shares each trading day through March 31, 2009 and is permitted to purchase 1,000 common shares each trading day thereafter. As at September 30, 2009, the Company had purchased 122,416 common shares at an average price of \$14.69 per share. Common shares purchased under the program are cancelled.

Capital Resources

The Company does not have material commitments for capital expenditures at this time. Planned capital expenditures in the last quarter of 2009 are approximately \$3.8 million in order to maintain the transmission and distribution system and to provide for expansions of its distribution system to service new customers. A new distribution system is being installed in Tomslake, a low density rural area located in the Dawson Creek service area. Just over \$1.7 million of the planned capital expenditures in last quarter of 2009 are in respect of the Tomslake system. In addition, the Company's share of funding of the development expenditures for the KSL Project through PTP is expected to be approximately \$0.1 million in the last three months of 2009. The Company expects to finance these expenditures from cash flow from operations and draws on the Company's debt facilities as required.

Business Risk Management

A detailed discussion of the Company's significant business risks is provided in the MD&A for the year ended December 31, 2008 and in the Company's 2009 Annual Information Form, both of which can be found at www.sedar.com. There were no changes to the Company's significant business risks during the nine months ended September 30, 2009 except as described below:

Impact of Global Economic Downturn

Usage Risk and Impact of Changes in Economic Conditions: In particular, economic conditions in the Company's service areas affect the Company's results of operations and financial condition. Deliveries are affected by economic factors such as changes in employment levels, personal disposable income and level of business activity. New customer additions are related to the level of business activity, population growth and housing starts in the service area. Management cannot estimate the level of growth or contraction for the economy as a whole or for the economy of any particular region the Company serves. Adverse changes in the Company's financial condition and results of operations may occur as a result of continuing negative economic conditions, a decline in business activity, unemployment, contraction of credit availability or other factors affecting economic conditions generally.

Liquidity, Cash Flow, and Capital Availability Risks: Current global economic conditions have had significant adverse impacts on financial markets, including the equity and debt markets accessed by the Company to maintain liquidity. On July 8, 2009, the Company increased its operating line by \$5 million to \$25 million and renewed its term for 18 months to help manage these risks. The Company experienced significant increases in fees and credit spreads upon renewal of its operating line with these new terms.

Employee Future Benefits Plan Risk: The Company has a defined benefit pension plan for the majority of its employees and retirees. Contributions to the plan are established by actuarial valuations prepared every three years and filed with the appropriate regulatory authorities. The most recently filed valuation was prepared on December 31, 2006. The next valuation is required to be prepared at December 31, 2009 and will determine the contributions required from 2010 onwards. If the plan experiences negative returns, it may result in increased contribution requirements beyond 2009. As at September 30, 2009, the fair value of the pension plan assets increased by approximately 12 percent from the fair value at December 31, 2008 and has recovered a majority of the market losses experienced during 2008.

Off-Balance Sheet Arrangements

As of September 30, 2009, the Company had no off-balance sheet arrangements.

Transactions with Related Parties

There were no transactions with related parties during the three month and nine month periods ended September 30, 2009.

Critical Accounting Estimates

The preparation of the Company's consolidated financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures. These estimates are based on historical experience and current assumptions, and actual results may differ from these estimates under different assumptions and conditions. There were no material changes in the nature of the Company's critical accounting estimates during the nine months ended September 30, 2009 from those disclosed in the Company's MD&A for the year ended December 31, 2008.

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, adjusted for weather variations, which may differ from actual consumption patterns. The estimates of unbilled operating revenue at September 30, 2009 comprise 20 percent and 3 percent of the Company's operating revenues for the three and nine month periods ended September 30, 2009, respectively. Through future meter readings, the usage estimates are replaced with actual delivered volumes which will be reflected in the Company's financial results at that time.

Financial and Other Instruments

The Company utilizes natural gas commodity hedging contracts in order to manage the volatility inherent in the prices of its natural gas purchases. It may also utilize interest rate hedging contracts to reduce the volatility of the interest expense associated with its floating rate debt instruments. As of September 30, 2009, the Company had no interest rate hedging contracts outstanding.

The Company's annual gas contracting and gas price risk management plan was filed with and accepted by the Commission during the second quarter of 2009. The plan calls for gas price hedging, covering purchases over the November 1, 2009 through October 31, 2011 period, to be completed in stages beginning in May 2009. Each hedging transaction is subject to approval by the Company's price risk management plan committee.

At September 30, 2009, the Company had outstanding natural gas swap contracts, natural gas collar contracts and natural gas 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 Derivative Asset (\$000's)	Estimated Fair Value Derivative Liability (\$000's)
Natural gas swap contracts	4,280,550	43.4	Oct. 2009 to Oct. 2011	\$5.66 to \$10.87	—	5,100
Natural gas call options	12,400	0.1	Oct. 2009	Cap at \$10.08	—	—
Collar contracts	393,600	4.0	Oct. 2009 to Oct. 2010	Floors from \$6.24 to \$8.38; Caps from \$6.76 to \$11.46	—	225
Total	4,686,550	47.6			—	5,325

The fair value reflects the estimated amounts that the Company would receive or pay at September 30, 2009 to terminate the natural gas swap contracts, natural gas collar contracts, 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. As a result of the recognition of the derivative liability, the gas cost variance payable account was decreased by \$5.3 million, in accordance with specific regulatory treatment.

At December 31, 2008, the estimated fair value of these derivative instruments was a liability of \$5.5 million as follows:

Financial Instrument	Notional Quantity (GJ's)	Percent of Annual Gas Purchases (%)	Delivery Period	Price Range (per GJ)	Estimated Fair Value Derivative Asset (\$000's)	Estimated Fair Value Derivative Liability (\$000's)
Fixed price contracts	900,000	9.1	Jan. 2009 to Mar. 2009	\$9.31	—	2,885
Natural gas swap contracts	3,453,800	35.1	Jan. 2009 to Oct. 2010	\$6.25 to \$10.87	—	2,228
Natural gas call options	66,300	0.7	Jan. 2009 to Oct. 2009	\$10.08 to \$11.79	\$4	—
Collar contracts	406,600	4.1	Jan. 2009 to Oct. 2010	Floors from \$6.24 to \$8.38; Caps from \$8.40 to \$11.46	—	367
Total	4,826,700	49.0			\$4	5,480

Dividends

The Board of Directors declared a semi-annual dividend of 84.375 cents per share on the Company's 6-3/4 percent cumulative, redeemable, preferred shares, payable January 1, 2010 to the shareholders of record at the close of business on December 17, 2009.

The Board of Directors also declared a quarterly dividend of 25 cents per share on the Company's common shares, payable December 23, 2009 to shareholders of record at the close of business on December 8, 2009.

Pacific Northern Gas Ltd., for purposes of the Income Tax Act (Canada), and any similar provincial or territorial legislation, designates all dividends paid by Pacific Northern Gas Ltd. after December 31, 2005 to be "eligible dividends" unless otherwise notified by the Company. An eligible dividend paid to a Canadian resident is entitled to the enhanced dividend tax credit.

Changes in Accounting Policies

Accounting for Rate-Regulated Operations

In December 2007, the Canadian Institute of Chartered Accountants (“CICA”) issued the following new guidance in accounting for rate-regulated operations which applies to fiscal years beginning on or after January 1, 2009:

- the removal of the temporary exemption in Section 1100, Generally Accepted Accounting Principles, providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation ;
- the amendment to Section 3465, Income Taxes, to remove the exception for entities subject to rate regulation so they are required to recognize future income tax liabilities and assets as well as a regulatory asset or liability for the amount of future income taxes expected to be recovered or refunded to customers in future rates; and
- slight amendments to Accounting Guideline AcG-19, Disclosures by Entities Subject to Rate Regulation to reflect the above changes.

On January 1, 2009, the Company adopted these new standards retrospectively without restating prior year’s figures which resulted in the following:

- The Company recognized \$15.4 million of future income tax liabilities as well as a related regulatory asset for the amount of future income taxes expected to be recovered from customers in future rates. The regulatory deferral accounts recorded on the balance sheet are now presented on a gross basis. Previously they were presented net of deferred income taxes.
- The Company also recognized \$2.2 million of post retirement benefit liabilities composed of non-contributory health care and life insurance plans and a corresponding and offsetting regulatory asset for the same amount for non-pension post retirement benefits expected to be included in future rates and recovered from customers. Previously, the Company followed a partial accrual basis method of accounting for its non-pension post retirement benefits as directed by the Commission.

Goodwill and Intangible Assets

On January 1, 2009, the Company adopted the CICA Handbook Section 3064, Goodwill and Intangible Assets, which replaced Sections 3062, Goodwill and Other Intangible Assets, and 3450, Research and Development Costs. The new standard is aligned with International Financial Reporting Standards (“IFRS”) and provides more comprehensive guidance on the recognition, measurement, presentation and disclosure of goodwill and intangible assets in accordance with the definition of an asset and the criteria for asset recognition, in particular for internally generated intangible assets. The adoption of this standard had no impact on the Company’s consolidated financial statements.

Fair Value of Financial Assets and Liabilities

On January 20, 2009, the CICA published the Emerging Issues Committee (“EIC”) Abstract 173, Credit Risk and the Fair Value of Financial Assets and Liabilities. The EIC states that an entity’s own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. This recommendation is to be applied retrospectively without restatement of prior periods to all financial assets and liabilities measured at fair value in interim and annual financial statements ending on or after the date of issuance of the Abstract. The Company has adopted this standard and determined that it had no material impact on the Company’s consolidated financial statements.

Transition to International Financial Reporting Standards (IFRS)

In February, 2008, the Accounting Standards Board confirmed that publicly accountable enterprises are required to prepare financial statements in accordance with IFRS for years beginning on or after January 1, 2011, with comparative figures for the previous year. The Company expects the transition to IFRS to impact accounting, financial reporting, business processes and information systems.

PNG started its IFRS conversion project during the third quarter of 2008 and has established a formal project team. Regular reporting to the Audit Committee is taking place throughout the project.

The IFRS conversion project is composed of three phases: project planning, scoping and preliminary impact analysis; detailed diagnostics and evaluation of financial impacts, selection of accounting policies, and design of operational and business processes; and implementation and review.

The Company has completed the first phase of its transition plan which entailed a review of the major differences between Canadian GAAP and IFRS and has identified the following as the areas that are expected to have the most significant impact on its financial reporting: regulatory assets and liabilities, plant, property and equipment, employee future benefit plans, income taxes, the development of the opening balances in the consolidated balance sheets and significantly more disclosure in its financial statements.

The Company is currently in the process of assessing the impact of policy alternatives on its consolidated financial statements, determining its significant accounting policies under IFRS, and executing necessary modifications to financial systems and business processes, and is also determining their impact on internal controls.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Disclosure controls and procedures are controls and other procedures that are designed to: (a) provide reasonable assurance that material information required to be disclosed by the Company is accumulated and communicated to management to allow timely decisions regarding required disclosure; and (b) ensure that information required to be disclosed by the Company is recorded, processed, summarized, and reported within the time periods specified in applicable securities legislation.

Management is responsible for designing, establishing and maintaining the Company's system of internal control over financial reporting. The Company's internal control system was designed based on the framework outlined in Internal Control – Integrated Framework released by the Committee of Sponsoring Organizations of the Treadway Commission to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with Canadian GAAP.

The Company's Chief Executive Officer and Vice President, Finance (as chief financial officer) certified the appropriateness of the financial disclosures in the interim MD&A and unaudited interim consolidated financial statements for the period ended September 30, 2009. These executives also certified that they are responsible for the design of disclosure controls and procedures and internal control over financial reporting. There have been no changes in internal control over financial reporting during the nine months ended September 30, 2009 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. As in prior quarters, the Company's Audit Committee reviewed this MD&A and the attached unaudited interim consolidated financial statements and the Board of Directors approved the documents prior to their release.

Other

The Company files an Annual Information Form on SEDAR which can be accessed at www.sedar.com.

Pacific Northern Gas Ltd. had 3,542,164 common shares and 200,000 preferred shares outstanding as of October 29, 2009. These are the only issued securities of the Company and it has no securities outstanding which may be converted into voting or equity securities. As at October 29, 2009, under the normal course issuer bid, the Company repurchased on the open market and cancelled 122,416 common shares.

As at October 29, 2009 there were 346,040 options granted and outstanding (representing 9.8 percent of issued and outstanding common shares). Each option is exercisable for one common share.

"Roy G. Dyce"

President and Chief Executive Officer

October 29, 2009

PACIFIC NORTHERN GAS LTD.

Interim Consolidated Financial Statements

(Unaudited)

For the Three and Nine Months Ended September 30, 2009

PACIFIC NORTHERN GAS LTD.
CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)
(in thousands, except shares and per share data)

(UNAUDITED)	For the nine months ended September 30		For the three months ended September 30	
	<u>2009</u>	<u>2008</u>	<u>2009</u>	<u>2008</u>
Operating revenues:				
Gas sales and transportation services	\$58,135	\$61,228	\$8,704	\$11,213
Off system gas sales	9,603	25,208	66	876
Other [note 7]	5,221	5,259	1,730	1,745
	<u>72,959</u>	<u>91,695</u>	<u>10,500</u>	<u>13,834</u>
Cost of gas:				
Gas sales	30,380	34,057	3,326	5,822
Off system sales	9,603	25,208	66	876
	<u>39,983</u>	<u>59,265</u>	<u>3,392</u>	<u>6,698</u>
Operating margin	<u>32,976</u>	<u>32,430</u>	<u>7,108</u>	<u>7,136</u>
Operating and maintenance	9,318	8,542	3,117	2,763
Administrative and general	5,436	5,016	1,684	1,717
Amortization of deferred charges and credits	(161)	428	(39)	143
Municipal and other taxes	3,438	3,532	1,146	1,178
Depreciation	6,207	6,040	2,069	2,020
	<u>24,238</u>	<u>23,558</u>	<u>7,977</u>	<u>7,821</u>
Operating income	8,738	8,872	(869)	(685)
Investment and other income	27	51	6	2
	<u>8,765</u>	<u>8,923</u>	<u>(863)</u>	<u>(683)</u>
Income deductions:				
Interest on long term debt	4,234	4,875	1,432	1,656
Interest on short term debt	53	367	39	101
Project development expenditures	124	589	22	117
	<u>4,411</u>	<u>5,831</u>	<u>1,493</u>	<u>1,874</u>
Income (loss) before income taxes	<u>4,354</u>	<u>3,092</u>	<u>(2,356)</u>	<u>(2,557)</u>
Income taxes: [note 11]				
Currently payable (recoverable)	1,717	(437)	(597)	(1,028)
Deferred income taxes	—	885	—	2
Future income taxes	(459)	(134)	(99)	(3)
	<u>1,258</u>	<u>314</u>	<u>(696)</u>	<u>(1,029)</u>
Net income (loss) for the period	<u>\$3,096</u>	<u>\$2,778</u>	<u>(\$1,660)</u>	<u>(\$1,528)</u>
Comprehensive income (loss) for the period	<u>\$3,096</u>	<u>\$2,778</u>	<u>(\$1,660)</u>	<u>(\$1,528)</u>
For common shares:				
Net income (loss) for the period	\$3,096	\$2,778	(\$1,660)	(\$1,528)
Dividends on preferred shares	253	253	84	84
Net income (loss) applicable to common shares	<u>\$2,843</u>	<u>\$2,525</u>	<u>(\$1,744)</u>	<u>(\$1,612)</u>
Per common share:				
Basic	<u>\$0.79</u>	<u>\$0.69</u>	<u>(\$0.49)</u>	<u>(\$0.44)</u>
Diluted	<u>\$0.78</u>	<u>\$0.68</u>	<u>(\$0.49)</u>	<u>(\$0.44)</u>
Weighted average number of common shares outstanding:				
Basic	<u>3,610,584</u>	<u>3,664,580</u>	<u>3,559,746</u>	<u>3,664,580</u>
Diluted	<u>3,638,305</u>	<u>3,697,298</u>	<u>3,559,746</u>	<u>3,664,580</u>

See accompanying notes

PACIFIC NORTHERN GAS LTD.
CONSOLIDATED BALANCE SHEETS
AS AT SEPTEMBER 30, 2009 AND DECEMBER 31, 2008
(in thousands)

(UNAUDITED)	September 30,	December 31,
ASSETS	<u>2009</u>	<u>2008</u>
Current assets:		
Cash and cash equivalents <i>[note 12]</i>	\$ 2,090	\$577
Short term investments	2,000	—
Accounts receivable <i>[note 13]</i>	4,422	28,047
Gas purchase variance recoverable	—	4,171
Inventory of supplies and natural gas	955	2,227
Prepaid expenses	1,426	958
Derivative financial instruments <i>[note 13]</i>	—	1,843
Future income taxes <i>[note 11]</i>	2,363	—
	<u>13,256</u>	<u>37,823</u>
Plant, property and equipment	<u>177,121</u>	<u>177,773</u>
Other Items:		
Deferred charges	5,187	5,588
Other regulatory assets	6,141	581
Future income taxes <i>[note 11]</i>	—	284
	<u>11,328</u>	<u>6,453</u>
	<u>\$201,705</u>	<u>\$222,049</u>
LIABILITIES		
Current liabilities:		
Bank indebtedness	\$ —	\$ 2,998
Accounts payable and accrued liabilities	9,013	23,897
Gas purchase variance payable	493	—
Income taxes payable	690	486
Other taxes payable	1,892	4,064
Other current liabilities	225	—
Methanex Termination Payment deferral	548	3,781
Long term debt due within one year	2,500	2,400
Derivative financial instruments <i>[note 13]</i>	5,325	7,319
	<u>20,686</u>	<u>44,945</u>
Other liabilities	3,333	217
Long term debt, non-current portion	74,014	74,533
Deferred income taxes <i>[note 11]</i>	—	13,630
Future income taxes <i>[note 11]</i>	16,320	—
	<u>93,667</u>	<u>88,380</u>
	<u>114,353</u>	<u>133,325</u>
SHAREHOLDERS' EQUITY		
Preferred shares <i>[note 5]</i>	5,000	5,000
Common shares <i>[note 6]</i>	8,855	9,161
Share capital	13,855	14,161
Contributed surplus	3,588	3,610
Retained earnings	69,909	70,953
	<u>87,352</u>	<u>88,724</u>
	<u>\$201,705</u>	<u>\$222,049</u>

ON BEHALF OF THE BOARD

"Robert F. Chase"
Director

"Roy G. Dyce"
Director

See accompanying notes

PACIFIC NORTHERN GAS LTD.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(in thousands)

(UNAUDITED)	For the nine months ended September 30		For the three months ended September 30	
	<u>2009</u>	<u>2008</u>	<u>2009</u>	<u>2008</u>
Preferred shares	\$5,000	\$5,000	\$5,000	\$5,000
Common shares				
Balance at beginning of period	\$9,161	\$9,161	\$8,949	\$9,161
Share repurchase under normal course issuer bid [note 6]	(306)	—	(94)	—
Balance at end of period	\$8,855	\$9,161	\$8,855	\$9,161
Contributed surplus				
Balance at beginning of period	\$3,610	\$3,490	\$3,601	\$3,571
Stock option expense [note 3]	76	102	17	21
Share repurchase under normal course issuer bid [note 6]	(98)	—	(30)	—
Balance at end of period	\$3,588	\$3,592	\$3,588	\$3,592
Retained earnings				
Balance at beginning of period	\$70,953	\$68,578	\$72,983	\$71,103
Share repurchase under normal course issuer bid [note 6]	(1,409)	—	(522)	—
Net income (loss) for the period	3,096	2,778	(1,660)	(1,528)
Dividends — Preferred shares	(169)	(169)	—	—
Dividends — Common shares	(2,562)	(2,418)	(892)	(806)
Balance at end of period	\$69,909	\$68,769	\$69,909	\$68,769
Total Shareholders' equity	\$87,352	\$86,522	\$87,352	86,522

See accompanying notes

PACIFIC NORTHERN GAS LTD.
CONSOLIDATED STATEMENTS OF CASH FLOW
(in thousands)

(UNAUDITED)	For the nine months ended September 30		For the three months ended September 30	
	<u>2009</u>	<u>2008</u>	<u>2009</u>	<u>2008</u>
Operating activities:				
Net income (loss) for the period	\$3,096	\$2,778	(\$1,660)	(\$1,528)
Add (deduct) items not involving cash:				
Deferred income taxes	—	885	—	2
Future income taxes	(459)	(134)	(99)	(3)
Depreciation and amortization <i>[note 12]</i>	6,127	6,553	2,057	2,192
Amortization of Methanex Termination Payment deferral <i>[note 7]</i>	(4,917)	(4,967)	(1,642)	(1,663)
Stock option expense <i>[note 3]</i>	76	102	17	21
Deferred income taxes on deferred charges	—	(89)	—	271
Imputed interest on deferred charges	(55)	97	(12)	19
Other	(123)	(341)	(21)	(108)
	3,745	4,884	(1,360)	(797)
Non-cash working capital changes <i>[note 12]</i>	10,775	9,560	(101)	2,921
Net cash provided (used) by operating activities	14,520	14,444	(1,461)	2,124
Investing activities:				
Additions to short term investments	(2,000)	—	—	—
Additions to plant, property and equipment	(5,246)	(7,743)	(2,094)	(3,529)
Decrease in deferred charges and credits (2008 amounts are net of income taxes)	2,281	594	91	(143)
Net cash used in investing activities	(4,965)	(7,149)	(2,003)	(3,672)
Financing activities:				
Increase (decrease) in bank indebtedness	(2,998)	(4,478)	—	2,992
Issue of long term debt	3,000	—	—	—
Repayment of long term debt	(3,500)	(500)	(500)	(500)
Share repurchase under normal course issuer bid <i>[note 6]</i>	(1,813)	—	(646)	—
Dividends paid	(2,731)	(2,587)	(892)	(806)
Net cash used in financing activities	(8,042)	(7,565)	(2,038)	1,686
Increase (decrease) in cash during the period	1,513	(270)	(5,502)	138
Cash and cash equivalents, beginning of period	577	802	7,592	394
Cash and cash equivalents, end of period	\$2,090	\$532	\$2,090	\$532

Supplemental cash flow information [note 12]

See accompanying notes

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

These unaudited interim consolidated financial statements are prepared, from the records of the Company, in accordance with Canadian generally accepted accounting principles (“GAAP”), except that disclosures do not conform, in all respects, to the requirements for annual consolidated financial statements. While management believes that the disclosures presented are adequate to make the information not misleading, these consolidated financial statements and notes should be read in conjunction with the Company’s most recent annual consolidated financial statements.

These interim consolidated financial statements follow the same accounting policies and methods of their application as the Company’s most recent annual consolidated financial statements, except as described in note 1 below.

Earnings for the interim periods may not be indicative of results for the fiscal year due to weather variations and other factors.

1. CHANGES IN ACCOUNTING POLICIES

Accounting for Rate-Regulated Operations

In December 2007, the Canadian Institute of Chartered Accountants (“CICA”) issued the following new guidance in accounting for rate-regulated operations which applies to fiscal years beginning on or after January 1, 2009:

- the removal of the temporary exemption in Section 1100, Generally Accepted Accounting Principles, providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation ;
- the amendment to Section 3465, Income Taxes, to remove the exception for entities subject to rate regulation so they are required to recognize future income tax liabilities and assets as well as a regulatory asset or liability for the amount of future income taxes expected to be recovered or refunded to customers in future rates; and
- slight amendments to Accounting Guideline AcG-19, Disclosures by Entities Subject to Rate Regulation to reflect the above changes.

On January 1, 2009, the Company adopted these new standards retrospectively without restating prior year’s figures which resulted in the following:

- The Company recognized \$15.4 million of future income tax liabilities as well as a related regulatory asset for the amount of future income taxes expected to be recovered from customers in future rates (see note 11). The regulatory deferral accounts recorded on the balance sheet are now presented on a gross basis. Previously they were presented net of deferred income taxes.
- The Company also recognized \$2.2 million of post retirement benefit liabilities composed of non-contributory health care and life insurance plans and a corresponding and offsetting regulatory asset for the same amount for non-pension post retirement benefits expected to be included in future rates and recovered from customers. Previously, the Company followed a partial accrual basis method of accounting for its non-pension post retirement benefits as directed by the British Columbia Utilities Commission (the “Commission”).

1. CHANGES IN ACCOUNTING POLICIES (cont'd)

Goodwill and Intangible Assets

On January 1, 2009, the Company adopted the CICA Handbook Section 3064, Goodwill and Intangible Assets, which replaced Sections 3062, Goodwill and Other Intangible Assets, and 3450, Research and Development Costs. The new standard is aligned with International Financial Reporting Standards ("IFRS") and provides more comprehensive guidance on the recognition, measurement, presentation and disclosure of goodwill and intangible assets in accordance with the definition of an asset and the criteria for asset recognition, in particular for internally generated intangible assets. The adoption of this standard had no impact on the Company's consolidated financial statements.

Fair Value of Financial Assets and Liabilities

On January 20, 2009, the CICA published the Emerging Issues Committee ("EIC") Abstract 173, Credit Risk and the Fair Value of Financial Assets and Liabilities. The EIC states that an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. This recommendation is to be applied retrospectively without restatement of prior periods to all financial assets and liabilities measured at fair value in interim and annual financial statements ending on or after the date of issuance of the Abstract. The Company has adopted this standard and determined that it had no material impact on the Company's consolidated financial statements.

2. PRINCIPLES OF CONSOLIDATION

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, that 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 September 30:

	Direct and Indirect Interest Held by the Company (percent)	
	2009	2008
Subsidiaries:		
Pacific Northern Gas (N.E.) Ltd.	100	100
Joint Ventures and Non-Controlled Partnerships [note 9]:		
Pacific Trail Pipelines Limited Partnership	50	50
Pacific Trail Pipelines Management Inc.	50	50

3. STOCK-BASED COMPENSATION

The Company does not have any plans which result in the direct award of stock, stock appreciation rights and awards that call for settlement in cash or other assets, except as described below.

Stock Option Plan

The Company has one stock option plan. No options were issued in the third quarter of 2009. The compensation cost that has been charged against income (and credited to contributed surplus) in the three months and nine months ended September 30, 2009 is \$17,000 and \$76,000 (2008 - \$21,000 and \$102,000), respectively, and represents expense for options issued in the current and previous periods which are being amortized over their vesting period. 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:

	Nine months ended September 30, 2009	Three months ended September 30, 2009
Risk free interest rate	2.2%	—
Expected volatility (annualized)	22.3%	—
Expected years of option life (average)	7.5	—
Expected annual rate of dividends	7.5%	—

The fair value of the options granted at the time of the grants was \$50,000 in 2009 and \$114,000 in 2008. During 2009, 62,800 options were issued at an average exercise price of \$12.24. The fair value of each option granted was \$0.80.

Deferred Share Unit Plan

The Company has a deferred share unit plan for outside directors of the Company. Under this plan, an outside director may elect to defer all or a portion of total compensation as stock units of the Company's common shares. Director compensation expense is recorded in the period in which the compensation is earned. Changes in the amount of the compensation as a result of dividends and share price movement are recorded as director compensation expense in the period of the change.

There were 1,434 (2008 - 2,208) deferred share units granted for the three months ended September 30, 2009 and all units granted under the plan remained outstanding at that date, except for 2,395 units, which were redeemed with the retirement of a director on April 30, 2009. Liabilities related to this plan are recorded in accounts payable and accrued liabilities on the balance sheet and amounted to \$425,000 (2008 - \$255,000) at September 30, 2009. Directors' compensation related to this plan for the three month and nine month periods ended September 30, 2009 amounted to \$27,000 and \$93,000 (2008 - \$34,600 and \$99,400), respectively.

4. SEASONALITY

Due to the seasonal nature of natural gas sales, the Company generally reports net income in the first and fourth quarters of the year, and losses in the second and third quarters, reflecting the typical timing of the heating season.

5. PREFERRED SHARES

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

6. COMMON SHARES

On March 9, 2009, the Company commenced a normal course issuer bid to repurchase up to 300,000 of the Company's common shares at market prices over a period up to 12 months. As at September 30, 2009, the Company repurchased on the open market and cancelled 122,416 common shares at an average price of \$14.69 per share.

The Company has outstanding stock options for 346,040 common shares, of which 248,340 are exercisable at September 30, 2009. There were 183,640 (2008 – 178,100) stock options outstanding at September 30, 2009 that could potentially dilute basic earnings per share in the future for the nine months ended September 30, 2009, but 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. There were 182,200 (2008 – 298,100) stock options outstanding at September 30, 2009 that could potentially dilute basic earnings per share in the future for the three months ended September 30, 2009 but were not included in the computation of diluted earnings per share because for the three months ended September 30, 2009 the Company reported a net loss and therefore including these shares would have an anti-dilutive effect on earnings per share.

During the nine month period ended September 30, 2009, no common shares were issued by the Company.

7. METHANEX TERMINATION PAYMENT DEFERRAL

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 \$23.3 million on February 28, 2006, the effective date of the termination. As approved by the Commission, the termination payment was recorded in 2006, net of income taxes of \$7.96 million, as an interest bearing credit deferral, and is being amortized into income over the period from March 1, 2006 to October 31, 2009. For the three month and nine month periods ended September 30, 2009, \$1.6 million (2008 \$1.7 million) and \$4.9 million (2008 \$5.0 million) of the termination payment was included in other operating revenues, respectively.

8. COMMITMENTS

The Company's purchase commitments at September 30, 2009 under various gas supply and transportation service contracts expiring through 2012 were as follows:

	(in thousands)
2009	\$ 9,513
2010	20,249
2011	9,035
2012	4,049
2013	—
Thereafter	—
Total	<u>\$42,846</u>

9. 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.

9. JOINT VENTURES (cont'd)

The following amounts represent the Company's proportionate interest in Pacific Trail Pipelines Limited Partnership and its general partner, Pacific Trail Pipelines Management Inc. as at September 30, 2009 and December 31, 2008:

(in thousands)	At September 30, 2009	At December 31, 2008
Balance Sheet		
Current assets	\$ 80	\$110
Non-current assets	—	—
<hr/>		
Current liabilities	1	6
Non-current liabilities	—	—

Income Statement	For the nine months ended September 30		For the three months ended September 30	
	2009	2008	2009	2008
Revenues	\$ —	\$ —	\$ —	\$ —
Expenses	124	589	22	117
Net loss	(124)	(589)	(22)	(117)

Cash Flow				
Cash Provided by (Used In):				
Operations	(\$184)	(\$639)	(\$27)	(\$102)
Financing	100	500	—	250
Investments	—	—	—	—
Proportionate share of increase (decrease) in cash of joint ventures	(\$84)	(\$139)	(\$27)	\$148

10. RELATED PARTY TRANSACTIONS

There were no transactions with related parties during the three and nine month periods ended September 30, 2009 and September 20, 2008.

11. FUTURE INCOME TAXES

For rate setting purposes, the Company recovers tax expense based on the taxes payable method, as prescribed by the Commission. Under the income taxes currently payable method, no provisions are made for future income taxes as a result of temporary differences between the accounting basis and tax basis of assets and liabilities. Therefore, current rates do not include the recovery of future income taxes related to temporary differences. Consequently, the Company did not previously 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 (note 1). The Company does record future income taxes related to non-regulated activities.

11. FUTURE INCOME TAXES (cont'd)

From July 1, 1978 until November 1, 1986, the Company used the deferral income tax method for the purposes of rate setting and collected \$15.4 million of deferred tax liabilities from its customers. In its 2009 revenue requirement application for the Western system, the Company requested approval to draw down deferred income taxes by \$900,000 during 2009 with a credit applied to the cost of service. A drawdown of \$900,000 was also approved during each of the 2008 and 2007 revenue requirement applications. During the nine month period ended September 30, 2009, the previously collected deferred tax liabilities were drawn down by \$675,000 and as a result of the change in accounting for income taxes has been reflected in amortization of deferred charges and other.

As described in Note 1, the amendment to Section 3465 Income Taxes results in the recognition of future income tax assets and liabilities and related regulated liabilities and assets for the amount of the expected future income taxes to be refunded or recovered in future rates. The previously collected deferred tax liabilities has been offset against the regulated asset established for amounts expected to be recovered from customers in future rates. Accordingly, the Company will use the asset and liability method of accounting for income taxes for both its regulated and non regulated activities.

As at January 1, 2009, the impact of this amendment is the recognition of a \$15.4 million future income tax liability on regulated operations.

Future income tax assets and liabilities are comprised of the following:

(in thousands)	September 30, 2009	December 31, 2008
Plant, property & equipment	\$(14,140)	—
Employee future benefits	(224)	—
Methanex termination payment deferral	164	—
Gas purchase variance account	1,745	—
Deferred charges and credits	(794)	—
Other	(708)	\$284
Total	\$(13,957)	\$284
Current Future Income Taxes	\$2,363	—
Non current Future Income Taxes	(16,320)	\$284
Total	\$(13,957)	\$284

12. SUPPLEMENTAL CASH FLOW INFORMATION

(in thousands)	For the nine months ended September 30		For the three months ended September 30	
	2009	2008	2009	2008
Depreciation and amortization:				
Depreciation, per income statement	\$6,207	\$6,040	\$2,069	\$2,020
Amortization of deferred charges, per income statement	(161)	428	(39)	143
Amortization of debt issue costs, included in long term interest expense	81	85	27	29
Total depreciation and amortization	\$6,127	\$6,553	\$2,057	\$2,192

12. SUPPLEMENTAL CASH FLOW INFORMATION (cont'd)

(in thousands)	For the nine months ended September 30		For the three months ended September 30	
	2009	2008	2009	2008
Non-cash working capital changes:				
(Increase) decrease in:				
Accounts receivable	\$23,625	\$20,507	\$1,413	\$2,062
Income taxes recoverable	—	(595)	—	(1,036)
Inventories of supplies and natural gas	1,272	1	(67)	(218)
Prepaid expenses	(468)	112	(897)	(644)
Increase (decrease) in:				
Accounts payable and accrued liabilities	(15,623)	(8,528)	867	4,135
Gas purchase variance account	3,937	(789)	1,780	738
Income and other taxes payable	(1,968)	(1,148)	(3,197)	(2,116)
Attributable to operating activities	\$10,775	9,560	\$(101)	\$2,921
Interest and tax payments:				
Income taxes paid	\$1,461	\$150	\$285	—
Interest paid	\$3,731	\$4,381	\$961	\$1,114
Non-cash transactions:			At September 30	
			2009	2008
Property, plant and equipment purchases included in accounts payable and accrued liabilities			\$556	\$217

Cash and cash equivalents included in the consolidated statements of cash flow comprise the following balance sheet amounts:

	At September 30	
	2009	2008
Cash	\$ 1,084	\$ 532
Cash equivalents	1,006	—
Total cash and cash equivalents	\$ 2,090	\$ 532

Cash equivalents are comprised of highly liquid short term investments with original maturities of 90 days or less.

13. FINANCIAL INSTRUMENTS

Fair Values

Due to the short term nature of cash and cash equivalents, short term investments, accounts receivable, bank indebtedness, and accounts payable and accrued liabilities, their respective carrying amounts in the consolidated balance sheet approximate their fair value.

The fair value of the Company's floating rate long term debt instruments is estimated to be equal to their carrying amounts in the consolidated balance sheet due to the regular resetting of interest rates applicable to the instruments in relation to current market rates. The fair value of the Company's fixed rate long term debt instruments is estimated by reference to quoted market prices for instruments of similar credit quality and term. As of September 30, 2009, the estimated fair value of the long term debt is \$86.0 million.

At September 30, 2009, the Company had outstanding natural gas swap contracts and natural gas collar contracts 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 Derivative Asset (\$000's)	Estimated Fair Value Derivative Liability (\$000's)
Natural gas swap contracts	4,280,550	43.4	Oct. 2009 to Oct. 2011	\$5.66 to \$10.87	—	5,100
Natural gas call options	12,400	0.1	Oct. 2009	Cap at \$10.08	—	—
Collar contracts	393,600	4.0	Oct. 2009 to Oct. 2010	Floors from \$6.24 to \$8.38; Caps from \$6.76 to \$11.46	—	225
Total	4,686,550	47.6			—	5,325

The fair value reflects the estimated amounts that the Company would receive or pay at September 30, 2009 to terminate the natural gas swap contracts and natural gas collar contracts 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. As a result of the recognition of the derivative liability, the gas cost variance payable account was decreased by \$5.3 million in accordance with specific regulatory treatment.

13. FINANCIAL INSTRUMENTS (cont'd)

At December 31, 2008, the estimated fair value of these derivative instruments was a liability of \$5.5 million as follows:

Financial Instrument	Notional Quantity (GJ's)	Percent of Annual Gas Purchases (%)	Delivery Period	Price Range (per GJ)	Estimated Fair Value Derivative Asset (\$000's)	Estimated Fair Value Derivative Liability (\$000's)
Fixed price contracts	900,000	9.1	Jan. 2009 to Mar. 2009	\$9.31	—	2,885
Natural gas swap contracts	3,453,800	35.1	Jan. 2009 to Oct. 2010	\$6.25 to \$10.87	—	2,228
Natural gas call options	66,300	0.7	Jan. 2009 to Oct. 2009	\$10.08 to \$11.79	\$4	—
Collar contracts	406,600	4.1	Jan. 2009 to Oct. 2010	Floors from \$6.24 to \$8.38; Caps from \$8.40 to \$11.46	—	367
Total	4,826,700	49.0			\$4	5,480

Credit Risk

The Company is exposed to credit risk in the event that a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises mainly from its accounts receivable and derivative financial instruments. There has been no change to the Company's credit risk from the prior year. In accordance with established credit approval practices, the Company deals only with recognized high credit quality institutions as counterparties to its derivative instruments and physical off system gas sales and does not expect any counterparties to fail to meet its obligations. Should the Company incur a financial loss as a result of the failure of a counterparty to meet its obligations, the Company would require regulatory approval to recover related costs through future rate adjustments.

The Company's credit policy requires a review of each customer for creditworthiness and often will require residential and commercial customers to pay a customer deposit based on two times the highest estimated monthly gas consumption prior to the installation of service. For industrial customers, the Company has the right to require securities such as letters of credit should a customer fail to pay its bills. No letters of credit or alternate security are currently in place with any individual industrial customer.

13. FINANCIAL INSTRUMENTS (cont'd)

The Company establishes an allowance for doubtful accounts that represents its estimate of accounts receivable which may not be recoverable. The main components of this allowance are a specific provision that relates to individual significant exposures and a general provision for the core market (residential and commercial) customers based on past experience. The Company actively reviews the adequacy of its allowance for doubtful accounts.

The following table shows the breakdown of accounts receivables by major customer class:

(in thousands)

	September 30, 2009	December 31, 2008
Core Market – Residential and Commercial	\$5,552	\$21,513
Industrial customers	647	1,347
Off-system sales customers	—	6,580
Other	190	342
Accounts Receivable	\$6,389	\$29,782

The following table sets forth details of the aging of receivables:

(in thousands)

	September 30, 2009	December 31, 2008
Unbilled revenues	\$2,075	\$12,551
Past due 0 to 30 days (current)	2,344	15,431
Past due 31 to 90 days	137	212
Past due over 91 days	1,833	1,588
Sub-total accounts receivables	6,389	29,782
Less: Allowance for doubtful accounts	(1,967)	(1,735)
Total accounts receivables	\$4,422	\$28,047

Changes in the allowance for doubtful accounts are as follows:

(in thousands)

	Nine months ended September 30, 2009
Balance at January 1, 2009	\$1,735
Provision for doubtful accounts	235
Write-off of bad debts, net of recoveries, and other	(3)
Balance at September 30, 2009	\$1,967

13. FINANCIAL INSTRUMENTS (cont'd)

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet obligations associated with financial liabilities and commitments as they become due. The Company manages liquidity risk through the management of its capital structure and financial leverage. It also regularly monitors actual and projected cash flows. The Company believes that future cash flows generated from operations and access to additional liquidity through capital and banking markets will be adequate to meet its financial obligations in the foreseeable future.

At September 30, 2009, the Company had credit facilities which included a \$25 million operating line, a \$20 million 5-year revolving term facility maturing August 3, 2012, and a \$15 million risk management facility. The Company's operating line was increased by \$5 million to \$25 million on July 8, 2009, and its term renewed for 18 months such that it expires on January 7, 2011. As of September 30, 2009, the calculated borrowing base of the operating line was approximately \$6.9 million and actual utilization, all by way of issued letters of credit, was \$3.0 million. \$6.0 million was outstanding under the \$20 million revolving term facility at September 30, 2009 via Bankers' Acceptance equivalent loans. The Company's overall liquidity risk has not changed significantly from December 31, 2008.

Overall Market Risk

Market risk is the risk that changes in market prices, including foreign exchange, interest rates and commodity prices will affect the fair value of the Company's financial instruments. The Company is not exposed to any foreign exchange risks. The Company's overall market risk has not changed significantly from the prior year.

Market Risk - Commodity Prices

The commodity cost of natural gas can be highly volatile. The Company utilizes derivative and other financial instruments in connection with the management of gas supply. The Company enters into forward, future, swap, fixed price and option contracts to manage the impact of market fluctuations on assets, liabilities or other contractual commitments. Based on the current regulatory process, any gains or losses arising from utility related derivative financial instruments are treated as part of the flow through of gas supply costs in customer rates.

Market Risk - Interest Rates

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

14. CAPITAL MANAGEMENT

The Company's objective in managing capital remains unchanged from December 31, 2008. The capital structure consisted of the following components at September 30, 2009 and December 31, 2008: bank indebtedness, long term debt, preferred shares and common shareholders' equity.

The Company's objectives with its capital structure are:

- to maintain the proportion of common equity in its capital structure at the level approved by the Commission for the purpose of determining rates which is necessary to ensure that the Company has the opportunity to earn the rate of return on common equity allowed by the Commission; and,
- to maintain a credit rating at which the Company has sufficient access to capital and to natural gas and other supplies on reasonable terms to be able to provide safe, secure and reliable service to its customers, which in turn is critical to the Company's ongoing prosperity.

However, the Company is not currently able to meet both objectives as it believes that the proportion of common equity approved by the Commission is not sufficient to allow the Company to maintain a satisfactory credit rating. The Company currently carries approximately \$20 million more common equity on its balance sheet than is allowed by the Commission for the purpose of determining rates. The normal course issuer bid announced by the Company on March 4, 2009, for the purchase of up to 300,000 of its common shares on the facilities of the Toronto Stock Exchange, is expected to stabilize its common equity capitalization ratio this year following increases from 40.9 percent at December 31, 2002 to 49.6 percent at the end of 2008. Based on discussions with its rating agency, the Company does not believe that the normal course issuer bid will impact its credit rating. To further address this situation the Company has sought and will continue to seek relief from the Commission, including the filing of an application with the Commission in the third quarter of 2009 requesting an increase in the common equity allowed for the purpose of determining rates.

The financial terms and conditions of the Company's debentures and credit facilities remain unchanged since December 31, 2008, other than the changes to the Company's operating line per note 13 above. The operating line and \$20 million 5-year revolving term facility are subject to a financial covenant requiring the Company's debt leverage not to exceed 65 percent. The 5-year revolving term facility contains an additional covenant which states that if the Company's secured debt rating is less than BBB (low) or the Company has no debt rating, the Company must maintain an interest coverage of 2.0 times or higher using earnings before interest, income taxes and expenditures on the KSL Project to a cumulative maximum of \$10 million. The Company is in compliance with its debt covenants.

15. COMPARATIVE FIGURES

Certain items in the consolidated financial statements have been reclassified to conform to the 2009 presentation.

**PACIFIC NORTHERN GAS LTD.
FORM 52-109F2
CERTIFICATION OF INTERIM FILINGS**

I, Roy Dyce, the Chief Executive Officer of Pacific Northern Gas Ltd., certify that:

1. **Review:** I have reviewed the interim financial statements and interim MD&A (together, the "interim filings") of Pacific Northern Gas Ltd., ("the issuer") for the interim period ended September 30, 2009.
2. **No misrepresentations:** Based on my knowledge, having exercised reasonable diligence, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings.
3. **Fair presentation:** Based on my knowledge, having exercised reasonable diligence, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.
4. **Responsibility:** The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, for the issuer.
5. **Design:** Subject to the limitations, if any, described in paragraphs 5.2 and 5.3, the issuer's other certifying officer and I have, as at the end of the period covered by the interim filings
 - (a) designed DC&P, or caused it to be designed under our supervision, to provide reasonable assurance that
 - (i) material information relating to the issuer is made known to us by others, particularly during the period in which the interim filings are being prepared; and
 - (ii) information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation; and
 - (b) designed ICFR, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP.
- 5.1 **Control framework:** The control framework the issuer's other certifying officer and I used to design the issuer's ICFR is the Committee of Sponsoring Organizations of the Treadway Commission (COSO) Internal Control – Integrated Framework.

5.2 **ICFR – material weakness relating to design:** N/A

5.3 **Limitation on scope of design:** N/A

6. **Reporting changes in ICFR:** The issuer has disclosed in its interim MD&A any change in the issuer's ICFR that occurred during the period beginning on January 1, 2009 and ended on September 30, 2009 that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

“Roy G. Dyce”

Roy G. Dyce
Chief Executive Officer

Date: October 29, 2009

PACIFIC NORTHERN GAS LTD.
FORM 52-109F2
CERTIFICATION OF INTERIM FILINGS

I, Janet P. Kennedy, the Vice President, Finance of Pacific Northern Gas Ltd. (certifying as the chief financial officer of the Company), certify that:

1. **Review.** I have reviewed the interim financial statements and interim MD&A (together, the "interim filings") of Pacific Northern Gas Ltd., ("the issuer") for the interim period ended September 30, 2009.
2. **No misrepresentations:** Based on my knowledge, having exercised reasonable diligence, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings.
3. **Fair presentation:** Based on my knowledge, having exercised reasonable diligence, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.
4. **Responsibility:** The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, for the issuer.
5. **Design:** Subject to the limitations, if any, described in paragraphs 5.2 and 5.3, the issuer's other certifying officer and I have, as at the end of the period covered by the interim filings
 - (a) designed DC&P, or caused it to be designed under our supervision, to provide reasonable assurance that
 - (i) material information relating to the issuer is made known to us by others, particularly during the period in which the interim filings are being prepared; and
 - (ii) information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation; and
 - (b) designed ICFR, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP.
- 5.1 **Control framework:** The control framework the issuer's other certifying officer and I used to design the issuer's ICFR is the Committee of Sponsoring Organizations of the Treadway Commission (COSO) Internal Control – Integrated Framework.

5.2 **ICFR – material weakness relating to design:** N/A

5.3 **Limitation on scope of design:** N/A

6. **Reporting changes in ICFR:** The issuer has disclosed in its interim MD&A any change in the issuer's ICFR that occurred during the period beginning on January 1, 2009 and ended on September 30, 2009 that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

“Janet Kennedy”

Janet Kennedy
Vice President, Finance
(certifying as chief financial officer)

Date: October 29, 2009