



Interim Report

For the Three Months Ended March 31, 2010

April 29, 2010

Pacific Northern Gas Ltd.
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Pacific Northern Gas Ltd.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the Three Months Ended March 31, 2010

Dated April 29, 2010

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the unaudited consolidated financial statements of Pacific Northern Gas Ltd. (the "Company") as at and for the three months ended March 31, 2010. It should also be read in conjunction with the audited consolidated financial statements and MD&A in the Company's Annual Report for the year ended December 31, 2009. Information contained in the 2009 MD&A that is not addressed in this document remains substantially unchanged.

The financial data included in this discussion has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") and all dollar amounts are in Canadian dollars unless otherwise indicated.

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

Forward-Looking Statements

This MD&A includes forward-looking statements. Forward-looking statements relate to, among other things, (i) anticipated growth, financial performance and business prospects (ii) business and economic conditions, (iii) strategies, (iv) regulatory developments, (v) new services, (vi) market forces and (vii) technological developments. Specifically, forward-looking statements are made with respect to:

- The expected timing and results of regulatory decisions, including the Company's CAP/ROE Application (see "Regulatory Activities – Capital Structure and Equity Risk Premium Application");
- The expected timing of and expenditures for development and construction of the KSL Project (see "Business Overview – KSL Project");
- The expected timing for the commencement of transportation service for the potential Merrill Lynch Commodities Inc. ("Merrill Lynch") floating liquefied natural gas ("LNG") project and the cost of reactivating compressor stations to provide such service (see "Business Overview – Capacity Utilization on the Western System");
- Expectations regarding the benefits of the McNair Creek Acquisition (see "Business of the Company – Launch of Renewable Power Business");
- Expectations for growth of opportunities in renewable energy generation;
- Expectations regarding the trends in customer numbers in the Western and Northeastern service areas;
- Expectations regarding the impact of economic conditions on the Company's performance and prospects for growth; and
- Expectations for the level of and source of funding for capital expenditure requirements.

Many of these statements can be identified by words such as "believe", "expects", "expected", "will", "intends", "projects", "anticipates", "estimates", "continues" or similar words. 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 future growth opportunities;
- 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
- general economic 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 2010 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 (“IFRS”). 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 revenues less cost of gas. Operating margin is not a recognized measure under GAAP and does not have a standardized meaning prescribed by GAAP. Therefore, operating margin may not be comparable to similar measures presented by other issuers. 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

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

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

Interim Negotiated Settlements of the 2010 Revenue Requirements Applications

A negotiated settlement process ("NSP") was conducted over the February 8 to 10, 2010 period in respect of the 2010 revenue requirements applications for all of the Company's operating divisions. On March 4, 2010 the Commission approved the interim negotiated settlement agreements reached by the parties in February. The agreements are interim pending review of the Company's CAP/ROE Application which is described in more detail in the next section of this MD&A.

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 preserve a reasonable level of financial integrity. As a result, the Company's actual rate of return on common equity ("ROE") has been less than the ROE 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 PNG (N.E.) jointly filed the CAP/ROE Application with the Commission primarily to increase the deemed common equity from 40 to 47.5 percent in the Western system and from 36 to 42.5 percent in PNG (N.E.). The Company also requested Commission approval to increase its risk premium relative to the benchmark utility ROE from 65 to 75 basis points for the Western system and 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 of PNG (N.E.).

On December 16, 2009 the Commission issued its decision on an application by Terasen Gas Utilities that resulted in the benchmark ROE for 2009 being increased from 8.47 percent to 9.50 percent effective July 1, 2009. This resulted in an average annual benchmark ROE of 8.98 percent for 2009. The Western system and Tumbler Ridge division 2009 ROE increased from 9.12 to 9.63 percent and the Fort St. John/Dawson Creek division ROE for 2009 increased from 8.87 to 9.38 percent assuming currently approved relative risk premiums of 65 and 40 basis points, respectively.

The Company amended its CAP/ROE Application on December 21, 2009 to reflect the impact of the higher 2009 benchmark ROE. The Commission issued an Order on December 24, 2009 directing the Company to establish separate common equity deferral accounts for all divisions to record potential differences in the approved 2009 costs of service and the 2009 costs of service based on the applied for higher benchmark ROE and the higher relative risk premiums and common equity components applied for under the CAP/ROE Application. The 2009 financial results reflect only the impact of the higher benchmark ROE assuming the currently approved lower common equity components and equity risk premiums.

Under the interim 2010 revenue requirements applications settlement agreements the parties agreed to attempt to negotiate an agreement on the following matters in the context of the CAP/ROE Application:

1. The deemed common equity components used for rate making purposes.
2. The risk premium relative to the benchmark utility ROE.

3. The disposition of the Merrill Lynch option fees which were recorded in a deferral account for future potential disposition as a credit to the Western system cost of service.
4. The level of deferred income taxes draw down in 2010.
5. The disposition of the 2009 ROE deferral accounts established under Commission Order No. G-172-09.

The parties agreed that the permanent rates effective January 1, 2010 would be finalized having regard to the terms of settlement reached in respect of the above matters. The CAP/ROE Application negotiated settlement process commenced on April 26, 2010. The Company expects the negotiated settlement process will be completed in late May 2010 with the Commission approving permanent rates, effective January 1, 2010, that reflect the terms of settlement reached in respect of both the Company's 2010 revenue requirements applications and the CAP/ROE Application.

Launch of Renewable Power Business

On April 7, 2010, the Company announced a partnership with Skookum Power Holdings Corp. ("Skookum Power") to acquire the 9.8 megawatt McNair Creek "run of river" hydro-electricity generation facility from Kiewit Hydropower Investors Inc. and Renewable Power Corp. The McNair Creek facility is located on B.C.'s Sunshine Coast and has been in operation for more than 5 years. The facility's generation is committed for sale under a long-term contract to BC Hydro.

The Company has also entered into a joint development and operating agreement with Skookum Power gaining access to extensive expertise in hydrology, engineering and commercial development to support its new renewable power business platform. The principals of Skookum Power are former power company executives with collectively more than 50 years experience in the hydro-electricity and energy sectors.

The investment in the McNair Creek facility represents the launch of the Company's renewable power business as part of its business diversification strategy. The key elements of this strategy are to diversify the Company's risk profile, grow its asset base and enhance its cash flows.

The transaction was closed on April 19, 2010 with the Company acquiring a 97 percent interest in the McNair facility. The purchase price was approximately \$17 million and has been funded in part by the assumption of approximately \$9 million in non-recourse debt and the remainder in cash payments. The Company's cash purchase obligations were met through drawings on its existing financial resources. The Company's debt to capitalization will now be approximately 51 percent after the transaction. The transaction is expected to be cash flow positive and EPS accretive in 2011.

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 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 January 13, 2010 Apache Corporation's subsidiary Apache Canada Ltd. ("Apache") acquired 51 percent of the Terminal. Apache also acquired a 25.5 percent interest in PTP from Galveston LNG Inc., the parent company of Kitimat LNG Inc.

Subject to a number of conditions, construction of the KSL Project by PTP is planned to commence in 2012 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 such as a Certificate of Public Convenience and Necessity ("CPCN") from the Commission and other permits from the B.C. Oil and Gas Commission. The Company will be working to finalize transportation reservation agreements for the KSL Project in the second quarter of 2010 at which point it would file its CPCN application with the Commission. The Company can give no assurances that such agreements will be signed or other conditions will be satisfied or that construction of the KSL Project by PTP will proceed.

The Company's share of development expenditures for the KSL Project in the first quarter of 2010 were approximately \$276,000 (\$197,000 after income taxes). Following environmental certification, expenditures on the KSL Project have been minimized and will continue to be expensed until suitable commercial arrangements for firm gas transportation services by PTP are in place at which point development costs of the project would be capitalized. If, as expected by the Company, PTP completes commercial arrangements for the KSL Project in the second quarter of 2010, the Company expects its 50 percent share of KSL Project development costs in 2010 will total approximately \$5.5 million, of which approximately 90 percent would be capitalized. These costs would primarily relate to additional engineering and technical studies for the KSL Project pipeline.

Capacity Utilization on the Western System

A Letter Agreement with Merrill Lynch, approved by the Commission on April 23, 2009 provides Merrill Lynch with an option to contract for 75 MMcf per day of firm gas transportation service using existing capacity on the Company's Western pipeline system. If Merrill Lynch exercises its option, it would utilize the transportation service to deliver natural gas to a floating LNG vessel to be located on the Douglas Channel near Kitimat, B.C. The LNG would be transferred from the floating LNG plant to other LNG carriers for export.

In consideration of the payment of option fees of \$2.5 million, Merrill Lynch has an exclusive option until June 30, 2010 to contract for firm gas transportation capacity for a two to five year primary term, with a right to renew for an additional two to five year term. Merrill Lynch may extend the option period by up to three further six month periods, with payment of \$1 million for each extension. Negotiation of a transportation service agreement is ongoing and when finalized, it would be submitted to the Commission for acceptance as a filed tariff. The transportation service agreement would become effective following exercise of the option. In the unexpected event that the Commission does not accept the transportation service agreement, the Company would be required to refund the option fees to Merrill Lynch.

If the transportation service agreement comes into effect, the Company's Western pipeline system would be at full capacity utilization, generating approximately \$15 million per year of incremental revenue for the benefit of the Company and its customers. The cost to reactivate the facilities left idle when Methanex 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 continue to extend the 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 current comparable residential electricity rate. PNG expects gas commodity prices payable by the Company during 2010 will continue at existing levels which will maintain the relative competitiveness of gas 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 contributed to and are expected to result in higher electricity rates over the long term. 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 each July 1, to just under \$1.50 per GJ effective July 1, 2012. Notwithstanding the impacts of carbon tax on natural gas, the cessation of the Methanex Corporation ("Methanex") termination payment credit amortization and the closure of the West Fraser Eurocan Kitimat liner board mill in January 2010, the Company expects its retail gas rates will maintain their relative competitiveness with electricity rates as electricity rate increases have been higher than the impact of the carbon tax on natural gas prices and electricity rates are expected to rise over time to meet the Province's energy policy objectives as evidenced by the 9 percent increase in residential electricity prices on April 1, 2010.

Overall Performance

Net income for the three months ended March 31, 2010 was \$5.5 million, compared with net income of \$5.2 million for the corresponding period in 2009. After providing for preferred share dividends, basic earnings per common share in the three months ended March 31, 2010 were \$1.51 compared with earnings per common share of \$1.39 for the same period in 2009.

Net income for the quarter was higher in 2010 compared to 2009 by approximately \$0.3 million. This was mainly due to the higher weighted average ROE earned in the first quarter of 2010 of 10.09 percent compared to 9.07 percent in the first quarter of 2009, accounting for \$0.6 million. This increase has been partially offset by higher administrative expenditures incurred by the Company for its new strategic initiatives and expenditures for the KSL Project.

Included in net income for the three months ended March 31, 2010 are after-tax charges of \$0.2 million or \$0.06 per share relating to the Company's share of KSL Project development expenditures compared to \$0.04 million or \$0.01 per share for the corresponding period in 2009.

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 the warm weather experienced this period, the Company recorded in this deferral account, for recovery in future rates, an after-tax revenue variance of \$1.5 million for the three month period ended March 31, 2010.

Residential deliveries were approximately 18 percent lower in the three months ended March 31, 2010 and total commercial deliveries were 22 percent lower, relative to deliveries over the same period in 2009. Management believes that weather was a key factor in the decrease in both the residential and the commercial deliveries, as it was approximately 13 percent warmer for the three month period ended March 31, 2010 compared to the same period in 2009. The weather was also 5 percent warmer than normal for the three month period ended March 31, 2010, with "normal" based on the average of actual temperatures in the Company's service areas for the preceding 10 years.

Industrial deliveries were lower by approximately 33 percent for the three month period ended March 31, 2010 compared to the same period in 2009. The decrease in industrial deliveries is comprised of a 48 percent decrease in large industrial customer deliveries, mainly due to the closure of the West Fraser Mills Ltd. Kitimat liner board mill, combined with a 20 percent decrease in small industrial deliveries. The decrease in small industrial customer deliveries relate primarily to the Northeast system. 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 rate making purposes.

Results of Operations

Operating revenues in the three months ended March 31, 2010 decreased to \$40.2 million compared with \$48.3 million in the corresponding period in 2009. The decrease was primarily due to the lower commodity cost of gas embedded in rates as a result of declining gas market prices.

Operating margin in the three months ended March 31, 2010 increased to \$ 17.9 million, as compared with \$17.0 million in the same period in 2009, mainly due to the higher ROE in the first quarter of 2010 compared to the first quarter of 2009.

Included in project development expenditures and other income deductions for the three months ended March 31, 2010 are the Company's share of KSL Project development expenditures amounting to \$0.3 million before income taxes.

The Company filed a report with the Commission in March 2010 on past and projected gas supply costs compared to gas cost recoveries from customers. The report set out requested gas commodity cost rate changes effective April 1, 2010. On the basis of the report, the Commission approved the Company's request to increase propane commodity rates applicable to Granisle propane customers in the Western system and to make no changes to the Western system natural gas commodity rates. The Commission also approved increases in overall gas commodity rates applicable to PNG (N.E.)'s Fort St. John/Dawson Creek and Tumbler Ridge division customers. The increases ranged from \$0.458 to \$1.108 per GJ.

Summary of Quarterly Results

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

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

<i>(unaudited)</i>				
	June 30, 2009	Sept. 30, 2009	Dec. 31, 2009	Mar. 31, 2010
Revenues	\$14,141	\$10,500	\$31,172	\$40,235
Net income (loss)	(\$400)	(\$1,660)	\$3,436	\$5,488
Earnings (loss) per common share – basic	(\$0.13)	(\$0.49)	\$0.95	\$1.51
Earnings (loss) per common share – diluted	(\$0.13)	(\$0.49)	\$0.93	\$1.48
	June 30, 2008	Sept. 30, 2008	Dec. 31, 2008	Mar. 31, 2009
Revenues	\$20,332	\$13,834	\$41,144	\$48,318
Net income (loss)	(\$205)	(\$1,528)	\$3,159	\$5,156
Earnings (loss) per common share – basic	(\$0.08)	(\$0.44)	\$0.84	\$1.39
Earnings (loss) per common share – diluted	(\$0.08)	(\$0.44)	\$0.84	\$1.38

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 March 31, 2010, the Company's credit facilities include a \$25 million operating line, two \$15 million risk management facilities and a \$35 million committed 5-year term revolving debt facility. The operating line is subject to borrowing base requirements which may restrict the amount that the Company can borrow under the line at any point in time. In addition, the credit facilities are subject to financial covenants that may act to restrict the amounts that can be borrowed under the operating line and the 5-year term revolving debt facility.

The Company's operating line and risk management facilities are subject to renewal after 18 months with the operating line and one risk management facility maturing on January 7, 2011 and the other risk management facility maturing on July 18, 2011.

As of March 31, 2010, the calculated borrowing base of the operating line was approximately \$24 million and actual utilization was \$8.2 million. The Company was in compliance with the financial covenant under its operating line through March 31, 2010.

At March 31, 2010, \$6 million was outstanding under the revolving term facility under 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 acquisition of the McNair Creek facility was funded through the utilization of the Company's operating line facility.

Accounts receivable at March 31, 2010 were \$4.8 million lower than at December 31, 2009 mainly due to lower gas sales revenues in the month of March 2010 compared to the month of December 2009 as a result of lower volumes due to the warmer weather and due to lower gas commodity prices. Prepaid expenses remained at similar levels at the end of March 31, 2010 compared to December 31, 2009.

Accounts payable and accrued liabilities were lower by \$8.4 million mainly as a result of lower gas purchase costs in March 2010 compared to December 2009 due to much lower gas volumes and gas commodity prices.

The gas purchase variance account has increased by \$4.3 million resulting in an ending recoverable amount of \$5.5 million at March 31, 2010 compared to the ending recoverable balance of \$1.2 million at December 31, 2009. This was mainly due to the net liability fair value of the Company's derivative financial instruments recorded in the gas purchase variance account increased by \$3.7 million from \$4.0 million at December 31, 2009 to a net liability position of \$7.7 million at March 31, 2010.

Consistent with the prior year, the Company expects to make annual funding contributions to its pension plan of approximately \$1.3 million. The actual funding may change following completion of an actuarial valuation in the second quarter of 2010. The Company does not expect this to have a material impact on the Company's liquidity.

Normal Course Issuer Bid

The Company commenced a normal course issuer bid through the facilities of the Toronto Stock Exchange on March 9, 2009 which closed on March 8, 2010. During 2009, the Company had purchased and subsequently cancelled 122,416 common shares at an average price of \$14.69 per share. No further share purchases were made during the first quarter of 2010.

Capital Resources

Planned capital spending in 2010 is primarily directed toward installation of distribution mains and services in the Northeast system as well as transmission mainline rehabilitation in the Western system, and is forecast to be approximately \$7.9 million, of which \$1 million has been spent to date. Contractual commitments have yet to be made for major planned capital expenditures for 2010. These capital expenditures will be funded from cash flow from operations and, if required, draws on the Company's debt facilities.

The Company's share of planned capital expenditures for the KSL Project in 2010 is expected to be approximately \$5.5 million, of which approximately 90 percent would be capitalized, subject to completing commercial arrangements for the KSL Project transportation capacity by the second quarter of 2010.

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 July 1, 2010 to the shareholders of record at the close of business on June 16, 2010.

The Board of Directors also declared a quarterly dividend of 28 cents per share on the Company's common shares, payable June 22, 2010 to shareholders of record at the close of business on June 8, 2010.

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.

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, 2009 and in the Company's 2010 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 three months ended March 31, 2010 except as described below.

Impact of New Acquisition and Integration

The Company has launched into the renewable power business through its acquisition of the McNair Creek "run of the river" facility which closed on April 19, 2010. The Company will be spending time and resources to manage and integrate this new business into its current operations. Significant due diligence was performed prior to the closing of the acquisition, but management cannot provide assurance that it will not be incurring additional risks associated with this new business.

Off Balance Sheet Arrangements

As of March 31, 2010, the Company had no off-balance sheet arrangements.

Transactions with Related Parties

There were no transactions with related parties during the three month period ended March 31, 2010.

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 three months ended March 31, 2010 from those disclosed in the Company's MD&A for the year ended December 31, 2009.

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 March 31, 2010 comprise 15.5 percent of the Company's operating revenues for the three month period ended March 31, 2010. 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.

Future Accounting Pronouncements

Transition to International Financial Reporting Standards

In February 2008, the Canadian Accounting Standards Board confirmed that publicly accountable enterprises are required to prepare financial statements in accordance with International Financial Reporting Standards ("IFRS") for years beginning on or after January 1, 2011, with comparative figures for the previous year. IFRS are issued by the International Accounting Standards Board ("IASB").

The transition to IFRS will impact the Company's accounting policies, information technology and data systems, internal control over financial reporting, and financial statement presentation and disclosure. The transition may also impact the Company's operations, including such areas as contractual arrangements, debt covenants and compensation arrangements.

The Company commenced its IFRS transition project during the third quarter of 2008 and has established an IFRS transition plan and project team. The IFRS transition 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.

During the first quarter of 2010, the Company continued to work on elements of the second phase of the transition plan. A detailed analysis of standards and policy choices available under the standards identified the following areas as having the highest potential impact on the Company's financial reporting: regulatory assets and liabilities, property, plant and equipment, employee future benefit plans, presentation and disclosure, and the provisions related to the initial adoption of IFRS under IFRS 1, First Time Adoption.

A summary of progress in the review of these areas is as follows:

- **Rate-regulated activities:** On July 23, 2009, the IASB published Exposure Draft, *Rate-regulated Activities*, to develop a standard on rate-regulated activities that clarifies whether regulated entities could or should recognize an asset or liability as a result of rate regulation. As initially presented, this Exposure Draft would allow the Company to continue with balance sheet recognition of regulatory deferrals for rate setting purposes provided the activity is within scope. The IASB met in February 2010 to discuss responses to the exposure draft, however, it has not made any decisions on specific aspects of the project, except that it decided tentatively to finalise the transition relief for first-time adopters under IFRS 1 with respect to deemed cost of assets used in rate-regulated activities. This transitional relief is expected to be included in the omnibus *Improvements to IFRSs* due to be issued by the IASB in April 2010. In the absence of an approved standard for rate-regulated activities, it may be difficult to continue to qualify regulatory deferral accounts as assets and liabilities. This may have a significant impact on the Company's financial position and results. The Company continues to monitor the IASB's progress of this rate-regulated project.

- Property, plant and equipment: The Company has identified the following as differences between current accounting policies and IFRS compliant policies: the capitalization of inspections and major overhauls of the Company's transmission and distribution assets, the capitalization of overhead costs, the treatment of gains and losses on disposal of assets, the treatment of customer contributions, the capitalization of borrowing costs and asset retirement obligations. The Company is continuing with its review of these differences and the assessment of policy choices.
- Employee future benefit plans: The Company is continuing with its assessment of policy choices available under the current IFRS standard and is monitoring the ongoing developments related to the standard.
- Presentation and disclosure: The Company has completed the preparation and review of pro forma annual IFRS financial statements and has identified changes to presentation and additional disclosure required under IFRS. The Company continues to assess changes that will be required for interim financial reporting in the year of adoption.
- Derivative financial instruments: The Company currently records the fair value of a fixed-price natural gas supply contract at each reporting date and includes this amount in the fair value of its derivative financial instruments. Under regulatory accounting, an offsetting entry is made to the gas cost variance regulatory account. Under IFRS, the Company's fixed-price natural gas supply contract is a contract to buy or sell a non-financial item in accordance with the Company's expected purchase, sale or usage and will qualify for a scope exemption from being recognized as a financial instrument at fair value. Accordingly, as at January 1, 2010, the application of this exemption will result in a \$1.0 million decrease in derivative financial instrument assets, with an offsetting \$1.0 million debit adjustment to the gas cost variance regulatory account.
- IFRS 1, *First-Time Adoption of IFRS*: The elections and exemptions under IFRS 1 have been reviewed and analyzed, including proposed amendments relating to rate-regulated activities. Decisions that have been made regarding available IFRS 1 exemptions and elections include:
 - IFRS 3, *Business Combinations*: The Company has elected not to retrospectively apply IFRS 3 to business combinations that occurred prior to the January 1, 2010 transition date and such business combinations will not be restated.
 - IAS 19, *Employee Benefits*: The Company has elected to recognize all cumulative actuarial gains and losses as at the transition date. This decision will result in a \$6.4 million increase in the carrying value of liabilities related to defined benefit plans. The accounting treatment of the offsetting entry can not be finalized until the IASB provides additional guidance on the rate-regulated activities project.
 - Property, Plant and Equipment and Intangible Assets: Should the transitional relief discussed previously under rate-regulated activities be approved, the Company will be electing to use the carrying amounts under previous Canadian generally accepted accounting principles as at transition date of assets used in operations that are subject to rate regulation as their deemed cost under IFRS.

The Company continues to monitor changes to IFRS standards that may become effective during or shortly after the implementation phase.

The Company is also working on the implementation of changes to its financial information systems and processes to enable it to maintain data required to report its 2010 financial information under both Canadian GAAP and IFRS for comparative purposes.

The Company has conducted initial training sessions targeted to various levels of the organization. The Company will continue to provide training to key employees and will monitor the impacts on its business processes and information systems, and will develop a broader external communication plan.

The Company's transition plans are on schedule and further updates on the status of key activities for this project will be provided in future MD&A's.

Financial Instruments and Other Instruments

The Company utilizes natural gas commodity hedging contracts in order to manage the volatility inherent in the prices of its natural gas purchases. It may also utilize interest rate hedging contracts to reduce the volatility of the interest expense associated with its floating rate debt instruments. As of March 31, 2010 the Company had no interest rate hedging contracts outstanding.

During the second quarter of 2009, the Company completed its annual gas contracting and gas price risk management plan and filed it with the Commission for review and acceptance. The annual gas contracting plan covered proposed gas purchases over the November 1, 2009 to October 31, 2010 period while the gas price risk management plan provided for hedging gas purchases over the November 1, 2009 through October 31, 2011 period. The Company proposed implementing the hedges in stages over the May 2009 to February 2011 period. The Commission accepted the plan as filed except the percentage of planned options was reduced from 20 to 10 percent of the total volume of planned hedging. Each hedging transaction was approved by the Company's price risk management plan committee.

At March 31, 2010, the Company had outstanding natural gas swap contracts and collar contracts relating to natural gas supply as follows:

Financial instrument	Notional quantity (gigajoules)	Percent of annual gas purchases (%)	Delivery period	Price range (per gigajoule)	Estimated net fair value receivable (payable) (\$000's)
Natural gas swap contracts	3 200 000	32.8	Apr 2010 – Oct 2011	\$5.53 to \$9.11	(7,172)
Collar contracts	202 000	2.1	Apr 2010 – Oct 2010	\$5.30 to \$7.05 (floors) \$6.77 to \$10.06 (caps)	(502)
	3 402 000	34.9			(7,674)

The fair value reflects the estimated amounts that the Company would receive or pay at March 31, 2010 to terminate the natural gas swap contracts, and 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.

At December 31, 2009, the Company had outstanding fixed price contracts, natural gas swap contracts, and collar contracts relating to natural gas supply as follows:

Financial instrument	Notional quantity (gigajoules)	Percent of annual gas purchases (%)	Delivery period	Price range (per gigajoule)	Estimated net fair value receivable (payable) (\$'000's)
Fixed-price contracts	900 000	9.2	Jan 2010 – Mar 2010	\$4.03	1,021
Natural gas swap contracts	3 954 850	40.6	Jan 2010 – Oct 2011	\$4.96 to \$10.87	(4,568)
Collar contracts	308 650	3.2	Jan 2010 – Oct 2010	\$5.26 to \$8.38 (floors) \$6.76 to \$11.46 (caps)	(429)
	5 163 500	53.0			(3,976)

The fair value reflects the estimated amounts that the Company would receive or pay at December 31, 2009 to terminate the fixed price contracts, natural gas swap contracts, and collar contracts, based on the estimated net cash flows under the terms of each contract.

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 March 31, 2010. 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 quarter ended March 31, 2010 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 unaudited interim consolidated financial statements and the Board of Directors approved the documents prior to their release.

Outstanding Share Data

Pacific Northern Gas Ltd. had 3,591,264 common shares and 200,000 preferred shares outstanding as of April 29, 2010. These are the only issued securities of the Company and it has no securities outstanding which may be converted into voting or equity securities other than as noted below.

As at April 29, 2010 there were 335,240 stock options granted and outstanding (representing 9.3 percent of issued and outstanding common shares). Each option is exercisable for one common share.

"Roy G. Dyce"

President and Chief Executive Officer
April 29, 2010



Interim Consolidated Financial Statements

(Unaudited)

For the Three Months Ended March 31, 2010

Pacific Northern Gas Ltd.
CONSOLIDATED STATEMENTS OF INCOME AND
COMPREHENSIVE INCOME
Three months ended March 31
(Unaudited)

[\$ in thousands, except per share data]	2010	2009
Revenues:		
Gas sales and transportation services	29,051	37,104
Off system sales	11,063	9,475
Other <i>[note 6]</i>	121	1,739
	40,235	48,318
Cost of gas:		
Gas sales	11,275	21,813
Off system sales	11,063	9,475
	22,338	31,288
	17,897	17,030
Operating and maintenance	3,031	3,159
Administrative and general	2,299	1,881
Depreciation and amortization	2,100	2,015
Municipal and other taxes	1,173	1,146
	8,603	8,201
	9,294	8,829
Finance fees	1,449	1,365
Project development expenditures <i>[note 7]</i>	276	63
Income before income taxes	7,569	7,401
Income tax expense <i>[note 8]</i>	2,081	2,245
Net income and comprehensive income	5,488	5,156
Earnings per common share: <i>[note 9]</i>		
Basic	\$1.51	\$1.39
Diluted	\$1.48	\$1.38

The accompanying notes to the interim consolidated financial statements are an integral part of these financial statements.

Pacific Northern Gas Ltd.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

[\$ in thousands]	March 31 2010	December 31 2009
ASSETS		
Current assets:		
Cash and cash equivalents <i>[note 17]</i>	902	1,511
Accounts receivable <i>[note 15]</i>	16,809	21,618
Gas purchase variance recoverable	5,498	1,165
Inventories of natural gas and supplies	943	1,079
Prepaid expenses	965	940
Derivative financial instruments <i>[note 14]</i>	—	1,029
Future income taxes	830	1,288
	25,947	28,630
Plant, property and equipment	177,234	178,420
Intangible assets	1,778	1,795
Regulatory and other assets	14,186	11,364
	219,145	220,209
LIABILITIES		
Current liabilities:		
Bank indebtedness	2,461	2,579
Accounts payable and accrued liabilities	13,205	21,617
Income taxes payable	1,173	1,041
Other taxes payable	2,807	3,525
Derivative financial instruments <i>[note 14]</i>	6,268	4,298
Long-term debt due within one year	2,800	2,800
	28,714	35,860
Long-term debt, non-current portion	71,727	71,779
Regulatory and other liabilities <i>[note 14]</i>	6,500	5,684
Future income taxes	16,807	16,450
	123,748	129,773
SHAREHOLDERS' EQUITY		
Preferred shares	5,000	5,000
Common shares <i>[note 10]</i>	8,971	8,890
Contributed surplus	4,096	3,699
Retained earnings	77,330	72,847
	95,397	90,436
	219,145	220,209

The accompanying notes to the interim consolidated financial statements are an integral part of these financial statements.

On behalf of the Board:

"Roy G. Dyce"

Director

"Robert F. Chase"

Director

Pacific Northern Gas Ltd.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
Three months ended March 31
(Unaudited)

[\$ in thousands]	2010	2009
Preferred shares		
Balance, beginning and end of period	5,000	5,000
Common shares		
Balance, beginning of period	8,890	9,161
Share repurchase under normal course issuer bid <i>[note 10]</i>	—	(67)
Employee stock options exercised	81	—
Balance, end of period	8,971	9,094
Contributed surplus		
Balance, beginning of period	3,699	3,610
Stock option expense <i>[note 11]</i>	46	41
Share repurchase under normal course issuer bid <i>[note 10]</i>	—	(22)
Employee stock options exercised	351	—
Balance, end of period	4,096	3,629
Retained earnings		
Balance, beginning of period	72,847	70,953
Net income	5,488	5,156
Dividends – common shares	(1,005)	(842)
Share repurchase under normal course issuer bid <i>[note 10]</i>	—	(249)
Balance, end of period	77,330	75,018
Total Shareholders' Equity	95,397	92,741

The accompanying notes to the interim consolidated financial statements are an integral part of these financial statements.

Pacific Northern Gas Ltd.
CONSOLIDATED STATEMENTS OF CASH FLOWS
Three months ended March 31
(Unaudited)

[\$ in thousands]	2010	2009
OPERATING ACTIVITIES		
Net income	5,488	5,156
Add (deduct) items not involving cash:		
Future income taxes <i>[note 8]</i>	815	(706)
Depreciation and amortization	2,100	2,015
Amortization of Methanex termination payment deferral <i>[note 6]</i>	—	(1,634)
Stock option expense <i>[note 11]</i>	46	41
Imputed interest on regulatory assets and liabilities	163	—
Other	(82)	8
	8,530	4,880
Changes in operating assets and liabilities <i>[note 17]</i>	(7,418)	2,113
Net cash provided by operating activities	1,112	6,993
INVESTING ACTIVITIES		
Additions to plant, property and equipment	(915)	(1,248)
Net cash used in investing activities	(915)	(1,248)
FINANCING ACTIVITIES		
Repayment of bank indebtedness	(118)	(2,998)
Debt refinancing costs	(115)	—
Issuance of long-term debt	—	3,000
Share repurchase under normal course issuer bid <i>[note 10]</i>	—	(338)
Employee stock options exercised <i>[note 11]</i>	432	—
Dividends paid	(1,005)	(842)
Net cash used in financing activities	(806)	(1,178)
(Decrease) increase in cash and cash equivalents	(609)	4,567
Cash and cash equivalents, beginning of period	1,511	577
Cash and cash equivalents, end of period	902	5,144

Supplemental cash flow information *[note 17]*

The accompanying notes to the interim consolidated financial statements are an integral part of these financial statements.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2010
(Unaudited)

1. DESCRIPTION OF THE BUSINESS

Pacific Northern Gas Ltd. (the “Company”) and its wholly-owned subsidiary, Pacific Northern Gas (N.E.) Ltd. (“PNG (N.E.)”), are engaged in the transportation and distribution of natural gas in northern British Columbia, Canada. The Company and PNG (N.E.) are subject to regulation by the British Columbia Utilities Commission (the “Commission”) which, among other things, approves rates charged to customers.

The Company operates a transmission and distribution system in the west-central portion of northern British Columbia (“Western system”) and PNG (N.E.) operates a distribution system in northeastern British Columbia (“Northeast system”). Together, the Company and PNG (N.E.) operate over 3,500 kilometres of transmission and distribution pipeline and serve a base of more than 39,000 residential, commercial and industrial customers.

2. BASIS OF PRESENTATION

These interim consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”), including selected accounting treatments that differ from those used by entities not subject to rate regulation, except that disclosures do not conform, in all respects, to the requirements for 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 for the year ended December 31, 2009, except as described below in note 4.

While management believes that the disclosures presented are adequate to make the information not misleading, these interim consolidated financial statements and notes should be read in conjunction with the Company’s most recent annual audited consolidated financial statements for the year ended December 31, 2009.

All financial figures are presented in Canadian dollars.

3. PRINCIPLES OF CONSOLIDATION

These consolidated financial statements include the accounts of the Company, its wholly-owned subsidiary PNG (N.E.), as well as the Company’s proportionate share of its 50% interest in the assets, liabilities, revenue and expenses of both Pacific Trail Pipelines Limited Partnership and its general partner, Pacific Trail Pipelines Management Inc. [see note 7].

All intercompany transactions and balances are eliminated, including on a pro rata basis for those related to the entities which have been proportionately consolidated.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2010
(Unaudited)

4. ACCOUNTING CHANGES

Business combinations, consolidated financial statements and non-controlling interests

Effective January 1, 2010, the Company early adopted the pronouncements of CICA Handbook Section 1582, *Business Combinations*, Section 1601, *Consolidated Financial Statements*, and Section 1602, *Non-Controlling Interests*.

Section 1582 was introduced to replace Section 1581, *Business Combinations*, and provides the Canadian equivalent to International Financial Reporting Standard IFRS 3 (revised), *Business Combinations*. Section 1582 specifies a number of changes, including: an expanded definition of a business, a requirement to measure all business acquisitions at fair value, a requirement to measure non-controlling interests at fair value, and a requirement to recognize acquisition related costs as expenditures in the period incurred.

Section 1601 and Section 1602 were introduced together to replace Section 1600, *Consolidated Financial Statements*, and provide the Canadian equivalent to the corresponding provisions of International Accounting Standard IAS 27 (revised), *Consolidated and Separate Financial Statements*. Section 1601 establishes standards for the preparation of consolidated financial statements and Section 1602 specifies that non-controlling interests be treated as a separate component of equity, instead of a liability or other item outside of equity.

The adoption of these standards had no impact on the Company's consolidated financial statements for the period ended March 31, 2010, other than additional disclosure related to a business acquisition that closed subsequent to March 31, 2010 [see note 18] and the expensing of the related acquisition costs incurred of \$0.2 million, rather than their deferral and inclusion as part of the cost of the business acquisition.

5. SEASONALITY

Earnings for interim reporting periods may not be indicative of results for the fiscal year due to weather variations and other factors. Specifically, due to the seasonal nature of the sale of natural gas for heating purposes, the Company generally reports net income in the first and fourth quarters of the year, and losses in the second and third quarters.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2010
(Unaudited)

6. METHANEX TERMINATION PAYMENT DEFERRAL

As approved by the Commission, a termination payment received from Methanex Corporation for approximately \$23.3 million was recorded in 2006, net of income taxes of \$7.96 million, as an interest bearing credit deferral. This payment was amortized into income over the period from March 1, 2006 to October 31, 2009. Other revenue for the three month period ended March 31, 2009, includes \$1.6 million related to this termination.

7. JOINT VENTURES

The following amounts represent the Company's 50% proportionate interest in assets, liabilities, revenues, expenditures and cash flows of Pacific Trail Pipelines Limited Partnership and its general partner, Pacific Trail Pipelines Management Inc.:

[\$ in thousands]	March 31 2010	December 31 2009
Balance Sheet		
Current assets	181	75
Non-current assets	—	—
Current liabilities	(184)	(33)
Non-current liabilities	—	—
<hr/>		
	Three months ended March 31	
[\$ in thousands]	2010	2009
Income Statement		
Revenues	—	—
Expenses	276	63
Net loss	(276)	(63)
<hr/>		
Cash Flows		
Cash provided by (used in):		
Operating activities	(101)	(29)
Financing activities	248	—
Investing activities	—	—
Increase (decrease) in cash	147	(29)

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2010
(Unaudited)

8. INCOME TAX EXPENSE

	Three months ended March 31	
[\$ in thousands]	2010	2009
Current income taxes	1,266	2,951
Future income tax expense (recovery)	815	(706)
	2,081	2,245

9. EARNINGS PER COMMON SHARE

	Three months ended March 31	
[\$ in thousands, except share and per share amounts]	2010	2009
Net income	5,488	5,156
Less: Dividends on preferred shares	(84)	(84)
Net income attributable to common shares	5,404	5,072
Basic weighted-average number of shares outstanding	3,577,144	3,661,106
Effect of dilutive securities:		
Stock options	76,710	12,331
Diluted weighted-average number of shares outstanding	3,653,854	3,673,437
Net income per common share		
Basic	\$ 1.51	\$ 1.39
Diluted	\$ 1.48	\$ 1.38

For the three months ended March 31, 2010, 38,300 stock options (2009 – 261,840) have been excluded from the computation of diluted weighted-average number of shares as the exercise price of these options was greater than the average market price of the Company's common shares during this period.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2010
(Unaudited)

10. COMMON SHARES

[\$ in thousands, except number of shares]	Number of shares	Share capital
Balance, December 31, 2008	3,664,580	9,161
Issue of shares under share option plan	13,800	35
Share repurchase	(122,416)	(306)
Balance, December 31, 2009	3,555,964	8,890
Issue of shares under share option plan	32,600	81
Balance, March 31, 2010	3,588,564	8,971

During the three months ended March 31, 2010, the Company issued 32,600 common shares on the exercise of stock options (2009 – nil).

The Company commenced a normal course issuer bid through the facilities of the Toronto Stock Exchange on March 9, 2009. During 2009, the Company had purchased and subsequently cancelled 122,416 common shares at an average price of \$14.69 per share. This bid closed on March 8, 2010, and no share purchases were made during the first quarter of 2010.

11. SHARE-BASED COMPENSATION

Stock Option Plan

During the three month period ended March 31, 2010, the Company issued 38,300 stock options with a total fair value of \$102,000 (2009 – 62,800 stock options with a total fair value of \$50,000). The fair value of option awards is estimated on the date of the grant using the Black-Scholes option pricing model. The following weighted-average assumptions were used in computing the fair value of share options granted for the periods noted:

	Three months ended March 31	
	2010	2009
Number of options awarded	38,300	62,800
Stock option fair value	\$2.66	\$0.80
Stock option exercise price	\$22.72	\$12.24
Expected volatility (annualized)	20.2%	22.3%
Dividend yield	4.9%	7.5%
Risk free interest rate	3.1%	2.2%
Estimated option life (years)	7.5	7.5

The share-based compensation expense recorded for the three months ended March 31, 2010 was \$46,000 (2009 - \$41,000).

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2010
(Unaudited)

11. SHARE-BASED COMPENSATION (continued)

The following table provides a summary of the changes to the Company's share option plan during the periods noted:

	Three months ended March 31			
	2010		2009	
	Number of options	Weighted- average exercise price [\$]	Number of options	Weighted- average exercise price [\$]
Outstanding, beginning of period	332,240	15.85	296,720	16.70
Granted	38,300	22.72	62,800	12.24
Exercised	(32,600)	13.24	—	—
Forfeited	—	—	(280)	18.10
Expired	—	—	(13,200)	24.50
Outstanding, end of period	337,940	16.87	346,040	15.59
Weighted-average exercise price of options exercisable at end of period		16.71		15.67

The following table summarizes information about share options outstanding and exercisable as at March 31, 2010:

Exercise price [\$]	Number of options outstanding	Weighted- average exercise price [\$]	Weighted- average remaining life [years]	Number of options exercisable
6.50 – 9.99	2,700	7.85	1.0	2,700
10.00 – 14.99	137,000	13.08	5.2	101,480
15.00 – 19.99	138,640	18.58	6.7	118,270
20.00 – 24.50	59,600	22.03	7.8	28,960
	337,940	16.87	6.3	251,410

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2010
(Unaudited)

11. SHARE-BASED COMPENSATION (continued)

Deferred Share Unit Plan

The following table provides a summary of the changes to the Company's deferred share unit plan:

[Units]	Three months ended March 31	
	2010	2009
Outstanding, beginning of period	24,545	17,824
Issued	2,218	3,284
Redemptions	—	—
Outstanding, end of period	26,763	21,108

The following table provides a summary of the changes to the liability associated with the Company's deferred share unit plan:

[\$ in thousands]	Three months ended March 31	
	2010	2009
Balance, beginning of period	460	241
Expensed	150	13
Redemptions	—	—
Balance, end of period	610	254

12. RELATED PARTY TRANSACTIONS

There were no transactions with related parties during the three month periods ended March 31, 2010 and March 31, 2009.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2010
(Unaudited)

13. COMMITMENTS

The Company has long-term natural gas purchase arrangements all of which are transacted at market prices and in the normal course of business. The Company's purchase commitments as at March 31, 2010 under various gas supply contracts expiring through 2015 were as follows:

[\$ in thousands]	
2010	7,546
2011	6,617
2012	3,248
2013	60
2014	60
Thereafter	50
Total	17,581

These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at March 31, 2010.

14. FINANCIAL INSTRUMENTS

Financial instruments by category

The fair value of the Company's financial instruments, including derivatives, reflects a point in time estimate based on information about the instruments as at the balance sheet dates. The estimates involve uncertainties and judgment and may not be relevant in predicting future earnings or cash flows.

Non-derivative financial instruments

The Company has designated its non-derivative financial instruments as follows:

[\$ in thousands]	March 31, 2010		December 31, 2009	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Held for trading				
Cash and cash equivalents	902	902	1,511	1,511
Loans and receivables				
Accounts receivable	16,809	16,809	21,618	21,618
Other financial liabilities				
Bank indebtedness	2,461	2,461	2,579	2,579
Accounts payable and accrued liabilities	13,205	13,205	21,617	21,617
Long-term debt, including current portion	74,527	84,033	74,579	82,674

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2010
(Unaudited)

14. FINANCIAL INSTRUMENTS (continued)

The fair values of financial instruments included in current assets and current liabilities in the Company's consolidated balance sheets approximate their carrying value, reflecting the short-term maturity of these instruments. The fair value of the Company's long-term debt is estimated by reference to quoted market prices for similar instruments, taking into account credit risk.

Derivative financial instruments

The Company hedges exposures to fluctuations in natural gas prices through the use of derivative financial instruments. The Company has a hedge line of credit of \$15 million (2009 - \$15 million) with its bank operating line provider that allows it to transact its natural gas swaps and collars and is secured by the pledge of a \$20 million debenture.

In January 2010, the Company entered into a second risk management facility with a new provider allowing it to hedge natural gas purchases in the amount of \$15.0 million. This facility is also secured by the pledge of a \$20 million debenture and has two financial covenants, one which requires the Company's debt leverage not to exceed 65 percent, and a second which requires the Company to maintain an interest coverage of 1.5 times or higher using earnings before interest, income taxes and expenditures on the KSL Project to a maximum of \$10.0 million. Further, if the Company's secured debt rating is less than BBB (low) or the Company has no debt rating, the interest coverage requirement increases to 2.0 times or higher.

The risk management facilities allow the Company to hedge natural gas purchases in accordance with its annual gas contracting and gas supply price risk management plan and to enter into interest rate hedging transactions to the extent of a total maximum exposure of \$15.0 million under each of its available facilities.

The following tables summarize the valuation of the Company's derivative financial instruments related to natural gas supply as at the dates noted:

As at March 31, 2010

Financial instrument	Notional quantity (gigajoules)	Percent of annual gas purchases (%)	Delivery period	Price range (per gigajoule)	Estimated net fair value receivable (payable) (\$000's)
Natural gas swap contracts	3 200 000	32.8	Apr 2010 – Oct 2011	\$5.53 to \$9.11	(7,172)
Collar contracts	202 000	2.1	Apr 2010 – Oct 2010	\$5.30 to \$7.05 (floors) \$6.77 to \$10.06 (caps)	(502)
	3 402 000	34.9			(7,674)

Of the \$7.7 million liability at March 31, 2010, \$6.3 million is recorded as a current liability and \$1.4 million recorded in non-current regulatory and other liabilities on the interim consolidated balance sheet.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2010
(Unaudited)

14. FINANCIAL INSTRUMENTS (continued)

As at December 31, 2009

Financial instrument	Notional quantity (gigajoules)	Percent of annual gas purchases (%)	Delivery period	Price range (per gigajoule)	Estimated net fair value receivable (payable) ((\$000's)
Fixed-price contracts	900 000	9.2	Jan 2010 – Mar 2010	\$4.03	1,021
Natural gas swap contracts	3 954 850	40.6	Jan 2010 – Oct 2011	\$4.96 to \$10.87	(4,568)
Collar contracts	308 650	3.2	Jan 2010 – Oct 2010	\$5.26 to \$8.38 (floors) \$6.76 to \$11.46 (caps)	(429)
	5 163 500	53.0			(3,976)

Of the \$4.0 million net liability at December 31, 2009, \$1.0 million is recorded as a current asset, \$4.3 million is recorded as a current liability and \$0.7 million is recorded in non-current regulatory and other liabilities on the interim consolidated balance sheet.

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

These estimated fair market values have no impact on earnings due to the regulated nature of the Company's operations. Based on the current regulatory process, any gains or losses arising from utility related financial instruments are recorded in the gas purchase variance account as part of the cost of gas to be received from or refunded to customers in future rates.

15. RISK MANAGEMENT

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. 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.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2010
(Unaudited)

15. RISK MANAGEMENT (continued)

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 of 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]	March 31 2010	December 31 2009
Core market – residential and commercial	14,370	18,746
Industrial customers	894	948
Off-system sales customers	2,170	3,831
Other	384	137
	17,818	23,662
Less: Allowance for doubtful accounts	(1,009)	(2,044)
	16,809	21,618

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

[\$ in thousands]	March 31 2010	December 31 2009
Unbilled revenues	7,495	10,729
Past due 0 to 30 days (current)	9,236	10,747
Past due 31 to 90 days	308	384
Past due over 91 days	779	1,802
	17,818	23,662
Less: Allowance for doubtful accounts	(1,009)	(2,044)
	16,809	21,618

Changes in the allowance for doubtful accounts are as follows:

[\$ in thousands]	March 31 2010	December 31 2009
Balance, beginning of period	2,044	1,735
Provision for doubtful accounts	66	313
Write-off of bad debts, net of recoveries, and other	(1,101)	(4)
Balance, end of period	1,009	2,044

Pacific Northern Gas Ltd.
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(Unaudited)

15. RISK MANAGEMENT (continued)

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. The Company's overall liquidity risk has improved slightly from December 31, 2009, with the increase in the availability of credit under its operating line, risk management facilities and 5-year term revolving debt facility.

On January 19, 2010, the Company arranged a second \$15.0 million risk management facility which matures on July 18, 2011, and on February 2, 2010 the Company amended its committed 5-year term revolving debt facility by increasing the credit available under the facility to \$35.0 million and extending the maturity date to January 30, 2015.

As at March 31, 2010, the Company's credit facilities include a \$25 million operating line, two \$15 million risk management facilities and a \$35 million committed 5-year term revolving debt facility. The operating line is subject to borrowing base requirements which may restrict the amount that the Company can borrow under the line at any point in time. As of March 31, 2010, the calculated borrowing base of the operating line was approximately \$24 million and actual utilization was \$8.2 million, and \$6.0 million was outstanding under the \$35 million revolving debt facility at March 31, 2010 via Bankers Acceptance equivalent loans.

The Company's operating line and the initial risk management facility are subject to renewal after 18 months and are scheduled to mature on January 7, 2011.

The Company maintains regular dialogue with the financial institutions that provide these facilities and has no reason to believe the facilities will not be renewed upon maturity. See "Market Risk – Interest Rates" below for additional information on how this may impact the Company's future results.

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 on its earnings. The Company's overall market risk has not changed significantly from the prior year.

Pacific Northern Gas Ltd.
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15. RISK MANAGEMENT (continued)

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

While underlying interest rates, such as prime and bankers' acceptances rates are subject to changes in the future, as are interest rate spreads on borrowings by the Company, the Company does not expect these changes to have a material impact on its financial results. 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.

16. CAPITAL MANAGEMENT

The Company's objective in managing capital remains unchanged from December 31, 2009. The capital structure consisted of the following components at March 31, 2010: bank indebtedness, long-term debt and shareholders' equity, totaling \$172.4 million [December 31, 2009 – \$167.6 million].

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 \$20.0 million more common equity on its balance sheet than is allowed by the Commission for the purpose of determining rates. To address this situation the Company has filed a Capital Structure and Equity Risk Premium Application (the "CAP/ROE Application") with the Commission to increase its deemed common equity and to increase its risk premium relative to the benchmark utility return on equity. The Company is currently undergoing a negotiated settlement process to attempt to negotiate an agreement on the CAP/ROE Application and is expecting this process to be completed in late May 2010.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2010
(Unaudited)

17. SUPPLEMENTAL CASH FLOW INFORMATION

[\$ in thousands]	March 31 2010	December 31 2009
Cash and cash equivalents:		
Cash and bank balances	902	503
Short-term demand deposits	—	1,008
	902	1,511
	Three months ended March 31	
[\$ in thousands]	2010	2009
Changes in operating assets and liabilities:		
(Increase) decrease in:		
Accounts receivable	4,809	5,646
Inventories of supplies and natural gas	136	1,171
Prepaid expenses	(25)	235
Increase (decrease) in:		
Accounts payable and accrued liabilities	(8,578)	(10,919)
Gas purchase variance recoverable	(758)	3,185
Income taxes payable	132	2,025
Other taxes payable	(718)	1
Changes in regulatory assets and liabilities	(2,416)	769
Attributable to operating activities	(7,418)	2,113
	Three months ended March 31	
[\$ in thousands]	2010	2009
Cash interest and tax payments:		
Income taxes paid	1,923	875
Interest paid	1,016	1,039
Non-cash transactions:		
Plant, property and equipment purchases		
included in accounts payable and accrued liabilities	16	66
Long-term debt issue costs included in regulatory and other assets	183	—

Pacific Northern Gas Ltd.
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18. SUBSEQUENT EVENT

On April 7, 2010, the Company announced a partnership with Skookum Power Holdings Corp. to acquire the 9.8 megawatt McNair Creek “run of river” hydro-electricity generation facility from Kiewit Hydropower Investors Inc. and Renewable Power Corp. The McNair Creek facility is located on B.C.’s Sunshine Coast and has been in operation for more than 5 years. The facility’s generation is committed for sale under a long-term contract to BC Hydro.

The investment in the McNair Creek facility represents the launch of the Company’s renewable power business as part of its business diversification strategy. The key elements of this strategy are to diversify the Company’s risk profile, grow its asset base and enhance its cash flows.

The transaction closed on April 19, 2010 with the Company acquiring a 97 percent share of the McNair facility. The purchase price is estimated to be approximately \$17 million and has been funded in part by the assumption of approximately \$9 million in non-recourse debt and the remainder in cash payments. The Company’s cash requirements have been met through drawings on its existing financial resources.

The Company is in the process of evaluating the fair value of the assets acquired and liabilities assumed and expects to complete its preliminary purchase price allocation by the second quarter of 2010.

19. COMPARATIVE FIGURES

Certain of the prior period’s comparative figures have been reclassified to conform to the financial presentation adopted in the current year.

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

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

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 March 31, 2010.
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, 2010 and ended on March 31, 2010 that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

Date: April 29, 2010

"Roy G. Dyce"

Roy G. Dyce
Chief Executive Officer

**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 the following:

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 March 31, 2010.
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, 2010 and ended on March 31, 2010 that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

Date: April 29, 2010

"Janet Kennedy"

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