



Interim Report

For the Three and Nine Months Ended September 30, 2011

November 4, 2011

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PACIFIC NORTHERN GAS LTD. MANAGEMENT'S DISCUSSION AND ANALYSIS September 30, 2011

Date: November 4, 2011

This management's discussion and analysis ("MD&A") should be read in conjunction with the interim consolidated financial statements of Pacific Northern Gas Ltd. ("the Company") as at and for the three and nine month periods ended September 30, 2011. It should also be read in conjunction with the audited consolidated financial statements of Pacific Northern Gas Ltd. ("PNG" or "the Company") and related notes for the year ended December 31, 2010. The financial data included in this discussion has been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), as defined by Part V of the Canadian Institute of Chartered Accountants ("CICA") Handbook (see "Accounting Changes – Future Accounting Pronouncements"), 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 expectations regarding:

- The completion and timing of completion of the proposed acquisition of all of the Company's issued and outstanding shares by AltaGas Ltd. ("AltaGas") (see "Pending Disposition of the Company");
- The timing of the potential receipt of a contingent payment relating to the sale of the Company's interest in Pacific Trail Pipelines Limited Partnership ("PTP") (see "Business Overview – Sale of the Company's Interest in PTP KSL Project");
- The timing for the commencement of transportation service for either the potential LNG Partners LLC ("LNG Partners") small scale liquefied natural gas ("LNG") export project or the Apache Canada, EOG Canada and Encana Corporation Kitimat LNG export facility, the cost of reactivating compressor stations to provide such service and the timing for the commencement of the operating and maintenance agreement with Apache Canada and EOG Canada to operate the KSL Project Pipeline (see "Business Overview – Potential to Increase Utilization on the Western System and also "Business Overview – Sale of the Company's Interest in PTP KSL Project");

- The benefits of the acquisition of the McNair Creek hydroelectric generation facility and the investment in Narrows Inlet Project, and the growth of opportunities in renewable energy generation (see “Business Overview - Renewable Energy Business”);
- The expected timing of and expenditures for development and construction of the Narrows Inlet Project (see “Business Overview – Renewable Energy Business”); and
- The competitiveness of retail gas rates relative to electricity rates (see “Business Overview - Competitiveness of Rates”).

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 and, in particular, the continuation of low gas prices in North America relative to global markets;
- forecasted gas deliveries as set out in the Company’s 2011 revenue requirements applications;
- 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 2011 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 adoption of United States Generally Accepted Accounting Principles ("US GAAP") effective January 1, 2012. 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 Canadian GAAP and does not have a standardized meaning prescribed by Canadian 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 gas transmission and distribution financial results are best measured by excluding the cost of gas which is flowed through to customer rates without a mark-up.

Pending Disposition of the Company

On October 30, 2011, the Company entered into a definitive agreement under which AltaGas Ltd. ("AltaGas") has agreed to acquire all of the issued and outstanding common shares of the Company for \$36.75 per share in cash. The proposed transaction is valued at \$230 million, including assumed debt and preferred shares.

The proposed transaction will proceed by way of a court-approved statutory plan of arrangement, the implementation of which is subject to approval by 66 2/3% of the votes cast by shareholders at a special meeting to be held on or about December 12, 2011, and by a majority of the 'minority' shareholders voting at the meeting. The proposed transaction is also subject to a number of other customary closing conditions, including regulatory approval by the Commission. If approved, the transaction is expected to close on or about December 13, 2011.

Business Overview

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 distribution systems in northeastern British Columbia (“Northeast system”). The Northeast system is comprised of two divisions, the Fort St. John/Dawson Creek division and the Tumbler Ridge division.

The Company also operates and owns a 97 percent interest in the 9.8 megawatt (“MW”) McNair Creek hydro-electricity generation facility (“McNair”) located on B.C.’s Sunshine Coast. The McNair facility’s generation is committed for sale under a long-term contract to BC Hydro. The Company is also pursuing new hydro-electric generation development projects and is committed to investing up to \$2.5 million in the Narrows Inlet Project, which is also located on B.C.’s Sunshine Coast. These funds will be used to advance this project to the start of construction which is expected by late 2012 (see “Business Overview – Renewable Energy Business”).

Business Strategy

The Company’s strategy is to increase shareholder value by optimizing the value of its existing assets and by growing and diversifying its business through targeted acquisition and development opportunities. The Company is focusing its strategic initiatives on enhancing value from its regulated business, pursuing expansion opportunities for new pipeline infrastructure to the west coast of British Columbia and evaluating development and acquisition opportunities in the renewable energy sector.

Sale of the Company's Interest in PTP KSL Project

PTP is developing the KSL Project, a proposed 463 kilometre natural gas pipeline from Summit Lake, B.C. to Kitimat, B.C. The KSL Project would serve the planned Kitimat LNG export facility being developed by Apache Canada Ltd. (“Apache Canada”), EOG Resources Canada Inc. (“EOG Canada”) and EnCana Corporation (“EnCana”). On February 4, 2011, the Company entered into an agreement to sell its 50 percent interest in PTP and the underlying KSL Project to Apache Canada and EOG Canada, the Company’s partners in the project, for payments of up to \$50 million. The transaction has two cash components, the first being a payment of \$30 million that the Company received on March 2, 2011 upon closing, and the second being a payment of \$20 million to be paid contingent on the purchasers making a decision to proceed with construction of the Kitimat LNG export facility. With the National Energy Board’s (“NEB”) October 2011 decision approving the application by the purchasers for a 20-year LNG export license, the Company considers there to be an increased likelihood that the purchasers will proceed with this project.

In connection with the sale of its interest in PTP, the Company agreed on the terms for 20-year transportation service agreements with each of Apache Canada and EOG Canada that would significantly increase the utilization of the Company's current pipeline if LNG Partners does not claim this capacity first. If the LNG Partners project does not proceed and the Kitimat LNG facility does proceed, combined Apache Canada and EOG Canada would use up to 50 MMcf per day of the Company's existing pipeline capacity to supplement KSL Project pipeline throughput. Initial deliveries would be 30 MMcf per day starting with initial LNG production and an additional 20 MMcf per day would occur if liquefaction capacity is later increased. Service under the agreements would commence with commercialization of the Kitimat LNG facility which is expected to occur in 2015. The transportation service agreements are subject to approval by the Commission.

Further, the Company negotiated with Apache Canada and EOG Canada the principal terms of an operating and maintenance agreement under which the Company would operate the KSL Project pipeline. This agreement will have an initial term of seven years with renewal provisions and will be subject to approval by the Commission.

Upon receipt of the first cash payment of \$30 million in March 2011, the Company recorded a net gain of \$24.2 million after transaction related costs (\$21.6 million after taxes). On March 3, 2011, the Company's Board of Directors declared a special dividend of \$3.00 per common share, which represented approximately \$11 million of the proceeds from the sale of PTP. On May 11, 2011, the Company's Board of Directors declared an additional special dividend of \$3.00 per common share, which represented an additional \$11 million of the remaining proceeds.

Should the second contingent payment of \$20 million be made, the total \$50 million sale proceeds would have an approximate value to shareholders of \$9 to \$10 per share after taxes and related expenses, including payments under the KSL Project management incentive plan. The disposition of PTP has resulted in its presentation as discontinued operations in the Company's financial statements in both 2011 and 2010.

The Company can give no assurances that construction of the Kitimat LNG facility will commence or will be completed, or that the second \$20 million contingent payment will be made.

Potential to Increase Utilization on the Western System

PNG believes there is potential to significantly increase utilization on its Western system beyond the volumes proposed for the Kitimat LNG project based on the expectation there is room for, and there may be demand for, more than one LNG export project or other natural gas related projects in the Company's service area.

PNG's assessment is based in part on the continuing price spread between natural gas in North America, the supply source; and Asia, the intended market. In North America, natural gas prices have been declining mainly because of technological advances used for the discovery of shale gas and other unconventional sources. This includes significant and growing reserves in Northeast British Columbia. At the same time, natural gas prices have increased in Asia due in part to the growth of Asian economies, especially China. There can be no assurance that the favourable trend will continue, or that any new LNG projects will actually be developed.

One such project includes LNG Partners' proposal to locate an LNG export facility on the Douglas Channel near Kitimat, B.C. In connection with this proposed project, the Company and LNG Partners are parties to a Commission approved transportation service agreement ("TSA") that provides LNG Partners with a capacity option of 80 MMcf per day on the Company's Western system. The TSA documents the option provisions and the transportation service provisions that would apply following exercise of the option. If LNG Partners exercises its option, the Company understands that the transportation service would be used to deliver natural gas to their LNG export facility for liquefaction and delivery to LNG markets in Asia. If service commences under the TSA, the Company's Western system would be at full capacity utilization, generating approximately \$16 million per year of incremental margin for the benefit of the Company and its customers. The cost to reactivate the facilities left idle when Methanex Corporation ("Methanex") ceased methanol production at this location 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 estimated cost of completing a compressor overhaul of \$0.5 million. For regulatory purposes, the Company anticipates expensing all reactivation costs in the first year of operation.

The Company has received option fees of \$5.5 million to secure the exclusive option under the TSA until December 31, 2011 to contract for firm gas transportation capacity for a two- to five-year primary term, with a right to renew for three additional five-year terms. LNG Partners may extend the option period one more time to June 30, 2012 by paying the Company an additional \$1 million by December 31, 2011. Under the TSA, if service commences by June 30, 2012, all of the option fees previously paid to the Company will be credited to transportation service fees payable in 2012. The option fee credit to LNG Partners will be reduced by \$0.5 million if service commences after June 30, 2012 but before December 31, 2012. A further reduction of \$0.5 million will apply if service commences after December 31, 2012. If notice of commencement of service is given by LNG Partners under the TSA and service does not commence by January 1, 2015 then the TSA would terminate and the Company would retain all option fees.

Recent progress made with regard to the LNG Partners project includes BC LNG Export Co-operative LLC, an affiliate of LNG Partners, making application to the NEB during the first quarter of 2011, seeking permission to export LNG. On October 17, 2011, the NEB set out a timetable for a written review of the application. Final written reply arguments from all parties are to be submitted to the NEB by December 7, 2011. Also noted in the application was that LNG export sales are anticipated to commence in the fourth quarter of 2013, leading PNG to expect a \$1 million reduction in option fee credits against future transportation fees payable by LNG Partners under the TSA.

The Company can give no assurances that LNG Partners will continue to extend the option or exercise its option to take capacity on the Western system.

Renewable Energy Business

The Company continues to advance its renewable energy strategy with an investment in the 45 MW Narrows Inlet run-of-river renewable energy project (“Narrows Inlet Project”), previously referred to as the Stl’ixwim Renewable Energy Initiative or the Stl’ixwim Project. The Narrows Inlet Project consists of five developments on four creeks that are located within a radius of 5 to 7 km of each other at the northern end of Narrows Inlet which is located approximately 35 km north of the town of Sechelt, British Columbia and lies within the Sechelt Nation’s traditional territory. The Narrows Inlet Project is expected to benefit from coastal precipitation patterns, some storage capacity and close proximity to the largest electricity load center in British Columbia.

The Company has formed Narrows Inlet Limited Partnership (“NILP”) with Skookum Power Holdings Corp. to undertake an investment of up to \$2.5 million to advance the Narrows Inlet Project to the start of construction. To September 30, 2011, the Company has invested \$1.7 million. Prior to the commencement of construction, the Company will make its final investment decision, and through NILP, will have an exclusive option to provide the construction equity, as well as an option to ensure NILP owns a 50 percent interest in the Narrows Inlet Project.

By partnering with Skookum Power Holdings Corp., as it did on the McNair Creek facility, the Company gains access to hydro development and construction expertise. Both parties are working closely with the team of existing Narrows Inlet Project developers, Renewable Power Corp. and Altaqua Renewable Power Corp., to advance the project through the B.C. Environmental Assessment process. Renewable Power Corp. has extensive experience in hydro project development, construction and operations and was the founding partner of the McNair Creek facility.

The Narrows Inlet Project was awarded a 30 year energy purchase agreement with B.C. Hydro in the spring of 2010. If NILP elects to proceed with funding construction, construction is projected to commence in late 2012, with an estimated capital cost of approximately \$190 million of which approximately \$20 million would be financed with equity provided by the Company.

Prerequisites to the commencement of construction for the Narrows Inlet Project include receiving the necessary environmental and construction permits, securing of contractor agreements to build the facilities and obtaining construction financing. The Company can give no assurances that these conditions will be satisfied or that NILP will proceed with the construction of the Narrows Inlet Project.

Closure of West Fraser Eurocan Paper Mill

West Fraser Timber Co. Ltd. (“West Fraser”) permanently closed its Kitimat B.C. linerboard mill at the end of January 2010 and terminated its contract with the Company effective November 30, 2010. On December 1, 2010 the Company received from West Fraser a contract termination payment of \$5.1 million. As per the 2011 revenue requirements application negotiated settlement agreement, the termination payment is being amortized into earnings over the remaining life of the agreement which was set to expire in December 2013. In addition, as was the case with the closure of Methanex’s methanol production facilities in 2005, the Company will mitigate the impact of lower margin recovery by managing its costs and by seeking Commission approval to recover the future loss of margin through standard rate applications to the Commission. Should these measures be approved, the Company anticipates limited impact on future earnings.

Competitiveness of Rates

As a distributor of natural gas, the Company monitors the competitiveness of its natural gas retail rates relative to alternative energy sources in its service areas. The Company’s current residential rates in all divisions are lower than the current comparable residential electricity rate. Declines in gas commodity prices payable by the Company during 2010 and in 2011 have helped to make gas rates more competitive relative to electricity. The current Western system bundled average residential rate is \$18.90 per GJ, including the July 1, 2011 carbon tax of \$1.2415 per GJ. This is approximately 23 percent less than the comparable residential conservation electricity rate of \$24.65 per GJ.

Overall Performance

The disposition of the Company’s interest in PTP has been presented as discontinued operations in accordance with Canadian accounting standards and the Company has restated its prior year’s figures to conform to this presentation.

Due to the seasonality of the business, a net loss of \$2.2 million was incurred in continuing operations for the three months ending September 30, 2011, essentially the same as for the corresponding period in 2010. After providing for preferred share dividends, the basic loss per common share for the three months ended September 30, 2011 was \$0.61 compared with a loss per common share of \$0.64 for the corresponding period in 2010. The allowed weighted average ROE remains at 10.09 percent for 2011, the same as in 2010.

The three month period ending September 30, 2010 includes a net loss from discontinued operations of \$39,000 for the Company’s share of KSL project development expenses incurred.

Net income from continuing operations for the nine months ending September 30, 2011 was \$3.0 million compared to \$3.5 million in the comparable period in 2010. This is mainly due to the \$1.1 million impact of the Capital Structure and Equity Risk Premium (“CAP/ROE”) Application settlement which was approved on June 23, 2010 and resulted in higher equity components in both the Western and Northeast systems. This included an adjustment to reflect the January 1, 2009 effective date for the higher Western system common equity capitalization ratio which was recorded in the second quarter of 2010. Offsetting this increase during 2010 were \$0.6 million of costs incurred for the McNair acquisition and reorganization during 2010.

As previously disclosed, the Company recognized net income from discontinued operations of \$20.9 million during 2011 composed of the net after tax gain of \$21.6 million recognized on the sale of the KSL project and \$0.7 million of the Company’s share of KSL project expenses incurred prior to its sale compared to a net loss of \$0.4 million in the nine months ended September 30, 2010.

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 colder weather experienced during 2011, the Company has recorded an after-tax revenue variance of \$1.1 million for the nine month period ended September 30, 2011 in this deferral account.

Natural Gas Volumes

The table below sets forth natural gas volumes delivered by PNG for the third quarter of 2011, compared with a year earlier.

[Deliveries in TJ]

Three months ended September 30	Third Quarter 2011	Third Quarter 2010	Percent Change
Sales:			
Residential	241	247	(2%)
Commercial	202	227	(11%)
Small Industrial	75	68	+12%
Large Industrial	7	2	+192%
Total Sales	525	544	(3%)
Transportation Service:			
Commercial	37	28	+31%
Small Industrial	534	505	+6%
Large Industrial	143	226	(37%)
Total Transportation Service	714	759	(6%)
Total Deliveries	1 239	1 303	(5%)
Nine months ended September 30	YTD September 30 2011	YTD September 30 2010	Percent Change
Sales:			
Residential	2 025	1 779	+14%
Commercial	1 618	1 500	+8%
Small Industrial	291	286	+2%
Large Industrial	7	2	+192%
Total Sales	3 941	3 567	+10%
Transportation Service:			
Commercial	242	162	+50%
Small Industrial	1 788	1 703	+5%
Large Industrial	579	888	(35%)
Total Transportation Service	2 609	2 753	(5%)
Total Deliveries	6 550	6 320	+4%

For the three months ended September 30, 2011, residential deliveries were approximately 2 percent lower and total commercial deliveries were 6 percent lower relative to deliveries over the same periods in 2010. During this period, weather was approximately 30 percent colder in the Western region and approximately 20 percent warmer in the Northeastern region compared to the same period in 2010 and resulted in overall lower net core customer deliveries as variations in weather during the summer months have less of an impact on deliveries due to the lower levels of consumption.

For the nine months ended September 30, 2011, residential deliveries were approximately 14 percent higher and total commercial deliveries were 12 percent higher relative to deliveries over the same periods in 2010. Management believes that weather was the main reason for the higher deliveries in the past nine months as it was approximately 14 percent colder during this period in 2011 compared to the same period in 2010.

Industrial deliveries were lower by approximately 5 percent for the three month period and 7 percent for the nine month period ended September 30, 2011 compared to the same periods in 2010. The decrease in industrial deliveries is comprised of a 35 percent decrease in large industrial customer deliveries, mainly due to the closure of the West Fraser Kitimat linerboard mill, combined with a 5 percent increase in deliveries to small industrial customers. The small industrial customer deliveries were higher primarily in the Western system due to significant gas demand for coal drying at Ridley Island Terminals reflecting the impact of colder weather and higher than normal coal shipments and increased deliveries to customers in the forest industry. 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

The following table summarizes the Company's revenues and operating results for continuing operations, by business segment. A discussion of discontinued operations can be found under "Business Overview – Sale of the Company's Interest in PTP KSL Project".

[\$ in thousands]

Continuing Operations	Gas Transmission and Distribution	Renewable Energy	Total
Three months ended September 30, 2011			
Revenues	\$8,435	\$496	\$8,931
Operating margin	6,250	496	6,746
Net loss from continuing operations	(2,208)	(10)	(2,218)
Three months ended September 30, 2010			
Revenues	\$9,473	\$ 209	\$9,682
Operating margin	6,385	209	6,594
Net loss from continuing operations	(1,826)	(382)	(2,208)
Nine months ended September 30, 2011			
Revenues	\$57,031	\$1,650	\$58,681
Operating margin	32,518	1,650	34,168
Net income (loss) from continuing operations	3,060	(46)	3,014
Nine months ended September 30, 2010			
Revenues	\$64,293	\$ 790	\$65,083
Operating margin	34,237	790	35,027
Net income (loss) from continuing operations	4,238	(754)	3,484

Gas Transmission and Distribution

Revenues in the three months ended September 30, 2011 were \$8.4 million compared with \$9.5 million in the same period in 2010. The \$1.1 million decrease reflected mainly lower commodity costs in 2011 compared to 2010 and the lower cost of service due mainly to changes in depreciation. Natural gas commodity prices are passed through to the Company's sales customers without mark-up.

Revenues in the nine months ended September 30, 2011 were \$57.0 million compared with \$64.3 million in the same period in 2010. The \$7.3 million decrease mainly reflected a reduction of \$4.8 million in off system gas sales, lower commodity costs in 2011 compared to 2010, a lower cost of service primarily due to changes in depreciation rates and a partial offset from higher sales volumes due to colder weather. Any profit or

loss realized on the sale of gas surplus to customer requirements (“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 nine month period of 2011 reflects the impact of higher deliveries to on system customers due to colder temperatures.

Operating margin in the three months ended September 30, 2011 decreased slightly to \$6.3 million, as compared with \$6.4 million in the same period in 2010. For the nine months ended September 30, 2011, operating margin also decreased to \$32.5 million as compared to \$34.2 million in the comparable period in 2010. The decrease of \$1.7 million for the nine months ended September 30, 2011 was mainly due to the recognition in the second quarter of 2010 of the impact of the CAP/ROE Application settlement which was approved on June 23, 2010 and resulted in higher equity components in both the Western and Northeast systems. In addition, the lower 2011 operating margins reflect the lower depreciation expense recovered from customers due to the extension of the useful life of assets following a depreciation study undertaken and implemented by the Company.

Renewable Energy

For the three months ended September 30, 2011, the McNair hydro-electric facility generated revenues and contributed net income of \$0.5 and \$0.1 million respectively, compared to revenues of \$0.2 million and a loss of \$0.2 million in the comparable period in 2010. Due to project development expenditures the Company’s renewable energy segment recorded net loss of approximately \$10,000 for the three months ended September 30, 2011. In the comparable period in 2010, the renewable energy segment recorded a net loss of \$0.4 million due mainly to after-tax transaction costs of \$0.1 million. Gross project development expenditures incurred in this segment were \$0.1 million in this past quarter, the same as in the comparable period in 2010.

For the nine months ended September 30, 2011, the McNair facility generated revenues and contributed net income of \$1.7 and \$0.3 million respectively, compared to \$0.8 and \$0.1 million in the nine months ended September 30, 2010. Due to project development expenditures the Company’s renewable energy segment incurred a net loss of \$46,000 for the nine months ended September 30, 2011. The comparable period in 2010 for the renewable energy segment was a net loss of \$0.8 million mainly due to \$0.6 million in after-tax transaction costs incurred for the McNair acquisition in the 2010 period. Further, the 2010 results are not directly comparable to 2011 results since the McNair facility was not acquired until April 19, 2010.

As described in the “Summary of Quarterly Results”, production from the McNair facility is seasonal. McNair experienced significantly above average hydrological conditions in the three months ended September 30, 2011 which has resulted in above average hydrologic conditions for the nine months ended September 30, 2011. Electricity generation from the McNair facility for the nine months ended September 30, 2011 was over 25 percent greater than the expected long-term average estimated using standard industry procedures.

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>	Dec. 31, 2010	Mar. 31, 2011	June 30, 2011	Sept. 30, 2011
Continuing Operations				
Revenues	\$30,081	\$37,479	\$12,271	\$8,931
Net income (loss)	\$4,162	\$5,970	\$(738)	\$(2,218)
Earnings (loss) per common share – basic	\$1.15	\$1.61	\$(0.22)	\$(0.61)
Earnings (loss) per common share – diluted	\$1.11	\$1.57	\$(0.22)	\$(0.61)
Total Operations ⁽¹⁾				
Net income (loss)	\$3,984	\$26,793	\$(690)	\$(2,218)
Earnings (loss) per common share – basic	\$1.10	\$7.32	\$(0.21)	\$(0.61)
Earnings (loss) per common share – diluted	\$1.06	\$7.11	\$(0.21)	\$(0.61)

	Dec. 31, 2009	Mar. 31, 2010	June 30, 2010	Sept. 30, 2010
Continuing Operations				
Revenues	\$31,172	\$40,235	\$15,166	\$9,682
Net income (loss)	\$3,476	\$5,687	\$5	\$(2,208)
Earnings (loss) per common share – basic	\$0.96	\$1.57	\$(0.02)	\$(0.63)
Earnings (loss) per common share – diluted	\$0.94	\$1.53	\$(0.02)	\$(0.63)
Total Operations ⁽¹⁾				
Net income (loss)	\$3,436	\$5,488	\$(148)	\$(2,247)
Earnings (loss) per common share – basic	\$0.95	\$1.51	\$(0.06)	\$(0.64)
Earnings (loss) per common share – diluted	\$0.93	\$1.47	\$(0.06)	\$(0.64)

⁽¹⁾ Total operations include the results of both continuing and discontinued operations.

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.

The Company's renewable energy business is also seasonal, with revenues from electricity sales highly correlated to the amount of precipitation, as well as the timing of snow pack melt in the catchment area of the McNair Creek hydroelectric power plant. The Company expects that almost 40 percent of its annual production will occur in the second quarter, only 10 percent will occur in the third quarter, with the first and fourth quarters providing the remainder of the production relatively equally.

Liquidity

At September 30, 2011, the Company has credit facilities which include a \$25 million operating line, two risk management facilities each secured by the pledge of a \$20 million debenture issued by the Company and a \$35 million committed 5-year term revolving debt facility.

Borrowings under the operating facility bear interest at prime rate or bankers' acceptance rates plus an applicable credit spread. The facility has a term of 18 months, expiring May 28, 2012. The Company may also issue letters of credit under the operating facility. As of September 30, 2011, actual utilization of the operating line was \$4.9 million.

The risk management facilities are available for use by the Company to hedge natural gas purchases and to enter into interest rate hedging transactions.

\$10.0 million was outstanding under the revolving term facility at September 30, 2011 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 debt repayments.

Cash and cash equivalents at September 30, 2011 of \$1.1 million were \$0.2 million lower than at December 31, 2010. Accounts receivable of \$6.7 million at September 30, 2011 were \$16.3 million lower than at December 31, 2010, mainly due to lower gas sales revenues in the month of September 2011 compared to December 2010 due to lower gas volumes and gas commodity prices and the inclusion of off system sales receivables of \$3.2 million at December 2010.

Accounts payable and accrued liabilities of \$14.0 million at September 30, 2011 were lower by \$4.9 million compared to December 31, 2010, mainly due to lower gas purchase costs in September 2011 as a result of lower gas volumes and lower commodity prices. At September 30, 2011, there was a \$0.9 million income tax payable balance compared to an income tax recoverable amount of \$1.3 million at December 31, 2010. This was mainly due to the accrual for taxes to be paid on the sale of the Company's interest in PTP.

The gas purchase variance recoverable account has decreased by \$1.8 million resulting in a net recoverable amount of \$2.7 million at September 30, 2011, compared to the net recoverable amount of \$4.5 million at December 31, 2010. This decrease was mainly due to the following three items: the net liability fair value of the Company's derivative financial instruments recorded in the gas purchase variance account decreased to a net

liability position of \$2.8 million at September 30, 2011, down \$3.3 million from \$6.1 million at December 31, 2010; the gas purchase variance account increased by \$0.9 million as the Company refunded amounts to customers via rate rider credits; and gas commodity costs paid by the Company in 2011 were less than the gas commodity cost rates paid by customers resulting in a decrease in the gas purchase variance account by \$0.6 million.

Capital Resources

Planned capital spending for gas transmission and distribution activities in 2011 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 \$7.4 million, of which \$6.2 million has been spent to date. These capital expenditures will be funded from cash flow from operations and, if required, draws on the Company's debt facilities.

For renewable energy projects, the Company has also undertaken to spend up to \$2.5 million related to the Narrows Inlet Project by mid-2012, of which \$1.7 million had been funded through September 30, 2011 (see "Business Overview – Renewable Energy Business").

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, 2012 to the shareholders of record at the close of business on December 16, 2011.

The Board of Directors declared a quarterly dividend of 30 cents per share on the Company's common shares, payable December 1, 2011 to shareholders of record at the close of business on November 17, 2011.

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, 2010 and in the Company's 2011 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 September 30, 2011, except for the Company's decision to adopt US GAAP for interim and annual financial statements beginning on January 1, 2012 (see "Accounting Changes – Future Accounting Pronouncements").

Off-Balance Sheet Arrangements

As of September 30, 2011, the Company had no off-balance sheet arrangements.

Transactions with Related Parties

The Company had no significant transactions with related parties during the three months and nine months period ended September 30, 2011.

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, current assumptions, and actual results may differ from these estimates under different assumptions and conditions.

Effective January 1, 2011, as described under "Accounting Changes – Changes Applied in 2011 – 2011 Revenue Requirements Application Changes" below, the Company made changes to accounting estimates related to the remaining useful lives of its plant and equipment assets and to the cost pools and capitalization rates for overhead costs capitalized to self-constructed plant and equipment. Other than these noted changes, there were no material changes in the nature of the Company's critical accounting estimates during the three months and nine months ended September 30, 2011 from those disclosed in the Company's MD&A for the year ended December 31, 2010.

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, 2011 comprise 20 and 3 percent of the Company's operating revenues for the three month and nine month period ended September 30, 2011. 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.

Accounting Changes

Changes Applied in 2011

2011 REVENUE REQUIREMENTS APPLICATION CHANGES

Effective January 1, 2011, the Company adopted the following new accounting policies and changes in accounting estimates on a prospective basis in accordance with its 2011 revenue requirements applications filed with the Commission. These changes in depreciation, capitalization of overheads and accounting for non-pension post-retirement benefits were accepted under negotiated settlements reached on April 27, 2011. The Commission approved the negotiated settlement agreements on May 20, 2011.

Depreciation of plant and equipment is recorded on a straight-line basis over the underlying assets' useful lives. Effective January 1, 2011, the Company implemented the recommendations contained in its 2010 depreciation study which resulted in adjustments to the estimated remaining useful lives of plant and equipment assets. For 2011, these changes are expected to result in a net decrease in depreciation expense of approximately \$2 million.

Other changes reflected in the Company's 2011 revenue requirements applications included a reduction in the pool of overhead costs subject to capitalization as part of the cost of plant and equipment and the inclusion of the full actuarially-determined expense for non-pension post-employment benefit plans. All of these changes were adopted on a prospective basis and are not expected to impact net earnings due to their inclusion in the 2011 revenue requirements applications.

CANADIAN ACCOUNTING STANDARD CHANGES

Financial Instruments – Recognition and Measurement

In June 2009, the CICA provided a clarification to Handbook Section 3855, Financial Instruments – Recognition and Measurement, with respect to the embedded prepayment option. The Section has been amended to clarify when an embedded prepayment option is separated from its host instrument for accounting purposes. The amendment states that if the exercise price of a prepayment option compensates the lender for an amount equivalent to the present value of the lost interest for the remaining term of the host instrument, the feature is considered closely related to the host contract in which it is embedded. The amendment applies to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The adoption of the amendments to Section 3855 had no effect on the Company's consolidated financial statements.

Comprehensive Revaluation of Assets and Liabilities

In August 2009, the CICA amended Handbook Section 1625, Comprehensive Revaluation of Assets and Liabilities, as a result of issuing Sections 1582, Business Combinations, 1601, Consolidated Financial Statements, and 1602, Non-Controlling Interests, in January 2009. The amendments require that when push-down accounting is used following the acquisition of an enterprise, the assets and liabilities are to be measured at the values used in accounting for the purchase transaction or transactions in accordance with Section 1582. The amendments also require that, when a future income tax asset that arose prior to the date of a comprehensive revaluation and that was not recognized in the comprehensive revaluation is subsequently recognized; the benefit should be recognized in accordance with Section 1582 and Section 3465, Income Taxes. The amendments apply prospectively to comprehensive revaluations of assets and liabilities occurring in fiscal years beginning on or after January 1, 2011. The adoption of the amendments to Section 1625 had no effect on the Company's consolidated financial statements.

Multiple Deliverable Revenue Arrangements

In December 2009, the CICA issued EIC-175, Multiple Deliverable Revenue Arrangements, replacing EIC-142, Revenue Arrangements with Multiple Deliverables. The changes were made in response to changes made to Accounting Standards Codification Topic 605-25, Revenue Recognition – Multiple Element Arrangements, under US GAAP, and more closely aligns the accounting requirements for multiple-element arrangements under Canadian GAAP with US GAAP and IFRS. EIC-175 addresses how to determine whether an arrangement involving multiple deliverables contains more than one accounting unit and, if so, how the consideration specified in the multiple element arrangement should be distributed between different accounting units. These recommendations are to be applied prospectively to revenue arrangements with multiple deliverables entered into or materially modified in the first annual fiscal period beginning on or after January 1, 2011. The adoption of EIC-175 had no effect on the Company's consolidated financial statements.

Future Accounting Pronouncements

TRANSITION TO NEW ACCOUNTING STANDARDS

The Canadian Accounting Standards Board ("AcSB") has determined 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. However, in October 2010, the AcSB issued an amendment to Part I of the CICA Handbook allowing for a one-year deferral for first-time adoption of IFRS for qualifying entities with rate-regulated activities. The Canadian Securities Administrators' regulations have also been amended to incorporate the AcSB's one-year deferral. As previously disclosed, the Company meets the requirements of a qualifying entity and elected to take the optional one-year deferral.

The Company's 2011 financial statements are prepared according to Part V of the CICA Handbook which was Canadian GAAP prior to the changeover to IFRS. Both Part V and US GAAP allow the use of rate-regulated accounting and the recognition of regulatory assets and liabilities that are recovered or settled through future rates in its financial statements. Currently, IFRS does not allow the recognition of regulatory assets and liabilities and there continues to be significant uncertainty as to when, and if, IFRS will readdress rate-regulated accounting.

Recently, certain Canadian securities commissions have issued exemption orders that enable qualified non-Securities and Exchange Commission ("SEC") issuers with "activities subject to rate regulation" to file their financial statements in accordance with US GAAP for the years commencing on or after January 1, 2012 but before January 1, 2015. Without this exemption order, an entity is required to be an SEC registrant in order to file its financial statements under US GAAP. Many Canadian regulated utilities have been granted exemptive relief from security regulators and will be filing their financial statements based on US GAAP commencing 2012.

The Company believes that US GAAP, which allows rate-regulated accounting, better represents and reflects the Company's financial position and results of its regulated business. Therefore, the Company has made the decision to pursue adoption of US GAAP effective January 1, 2012. In August 2011, the Company obtained the required exemption order from its security regulators, and in October 2011, the Commission approved the Company's September 7, 2011 application to adopt US GAAP for regulatory accounting and reporting purposes commencing on January 1, 2012 and ending on December 31, 2014.

US GAAP Conversion Project

PNG commenced its US GAAP conversion plan during July 2011 and has formed a US GAAP project team, which includes a dedicated project manager. The Company has also engaged a public accounting firm to provide technical accounting advice and to assist on its US GAAP conversion project. Regular reporting to the Audit Committee will take place throughout the project.

The US GAAP conversion project is composed of three phases:

Phase I - Planning, Scoping and Preliminary Impact Analysis: This was largely completed in September 2011.

Phase II - Detailed Diagnostics, Evaluation of Financial Impacts, and Design of operation and Business Processes: This includes preparing pro forma US GAAP financial statements.

Phase III - Implementation and Review: To be completed with the preparation of interim financial statements in accordance with US GAAP in the first quarter of 2012.

Based on the analysis completed to date, and the Company's ability to continue to follow rate-regulated accounting which allows the recognition of regulatory assets and liabilities, there have been no material differences identified between US GAAP and Canadian GAAP except for the following:

- Post-retirement benefits (pension and non-pension): Under Canadian GAAP, the accrued benefit asset or liability for defined benefit plans are recognized on the balance sheet. Under US GAAP, an entity is required to recognize the funded or unfunded status of defined benefit pension and non-pension post-retirement benefit plans as an asset or liability in its balance sheet and to recognize changes in the funded status through other comprehensive income. US GAAP also allows the use of the corridor approach for the recognition of actuarial gains and losses and the Company will maintain this methodology.
- Joint Ventures: Canadian GAAP allows the use of proportionate consolidation to account for certain investments. US GAAP does not permit the use of proportionate consolidation and requires such investments to be recorded using the equity method of accounting.

The Company is satisfied that its transition plans are on schedule and will continue to provide updates on the status of key activities in future Management's Discussion and Analysis.

In addition to planning for the adoption of US GAAP, the Company continues to monitor changes to standards that may become effective during or shortly after the implementation phase.

Financial Instruments and Other Instruments

The Company previously utilized 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, 2011, the Company had no interest rate hedging contracts outstanding.

During the second quarter of 2011, 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, 2011 to October 31, 2012 period, while the gas price risk management plan provided for hedging gas purchases over the November 1, 2012 through October 31, 2013 period. The Company proposed implementing the hedges in stages over the May 2011 to February 2013 period. In July 2011, the Commission accepted the annual gas contracting plan. The Company withdrew its gas price risk management plan from consideration by the Commission in response to the Commission's July 12, 2011 decision to deny approval of the FortisBC Energy Inc. price risk management plan. The

Company's cash flows will be subject to some additional volatility as a result of ceasing to implement new natural gas commodity hedging contracts. Current hedges will expire by October 2012.

At September 30, 2011, the Company had outstanding natural gas swap 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 payable (\$000's)
Natural gas swap contracts	2 538 000	28.7	Oct 2011 – Oct 2012	\$3.94 - \$6.49	(2,765)
Collar contracts	53 500	0.6	Apr 2012 – Oct 2012	\$3.80 (floor) - \$5.31 (cap)	(21)
	2 591 500	29.3			(2,786)

The fair value reflects the estimated amounts that the Company would receive or pay at September 30, 2011 to terminate the natural gas swap 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, 2010, the Company had outstanding fixed-price, natural gas swap 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 payable (\$000's)
Fixed-price contracts	900 000	9.4	Jan 2011 – Mar 2011	\$4.23	(678)
Natural gas swap contracts	3 846 600	40.2	Jan 2011 – Oct 2012	\$4.16 - \$7.26	(5,453)
Collar contracts	53 500	0.6	Apr 2012 – Oct 2012	\$3.80 (floor) - \$5.31 (cap)	(8)
	4 800 100	50.2			(6,139)

The fair value reflects the estimated amounts that the Company would receive or pay at December 31, 2010 to terminate the fixed-price, natural gas swap and collar contracts based on the estimated net cash flows under the terms of each contract.

Certification of Disclosure Controls and Procedures and Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICFR"), as those terms are defined in National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*. The objective of this instrument is to improve the quality, reliability and transparency of information that is filed or submitted under securities legislation.

Management, with the participation of the Chief Executive Officer and Vice President, Finance, acting as the Chief Financial Officer, have designed DC&P and ICFR to provide reasonable assurance that material information is reported to them on a timely basis; that financial reporting is reliable; and that financial statements prepared for external reporting purposes are in accordance with Canadian GAAP.

There have been no changes in the Company's ICFR that occurred during the period beginning July 1, 2011, and ended on September 30, 2011 that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

Outstanding Share Data

At November 4, 2011, there were 200,000 preferred shares and 3,786,104 common shares outstanding. The common shares are the only issued voting securities of the Company, and there are no securities outstanding which may be converted into voting or equity securities.

As at November 4, 2011, there were 171,800 stock options granted and outstanding (representing 5 percent of issued and outstanding common shares). Each option is exercisable for one common share.



Interim Consolidated Financial Statements

(Unaudited)

For the Three and Nine Months Ended September 30, 2011

Pacific Northern Gas Ltd.
CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND
COMPREHENSIVE INCOME (LOSS)
(Unaudited)

(\$ in thousands, except per share data)	For the nine months ended September 30		For the three months ended September 30	
	2011	2010	2011	2010
Revenues:				
Gas sales and transportation services	49,018	51,172	7,875	9,152
Off system gas sales	6,432	11,250	—	93
Electricity sales	1,650	790	496	209
Other	1,581	1,871	560	228
	58,681	65,083	8,931	9,682
Cost of gas:				
Gas sales	18,081	18,806	2,185	2,995
Off system sales	6,432	11,250	—	93
	24,513	30,056	2,185	3,088
	34,168	35,027	6,746	6,594
Operating and maintenance	9,958	9,149	3,402	2,978
Administrative and general	7,591	6,704	2,290	1,947
Depreciation and amortization (note 4)	4,249	6,480	1,399	2,199
Municipal and other taxes	3,708	3,566	1,237	1,199
	25,506	25,899	8,328	8,323
	8,662	9,128	(1,582)	(1,729)
Finance fees	5,102	4,715	1,605	1,678
Income (loss) from continuing operations before income tax expense	3,560	4,413	(3,187)	(3,407)
Income tax expense (recovery) (note 7)	546	929	(969)	(1,199)
Net income (loss) from continuing operations	3,014	3,484	(2,218)	(2,208)
Net income (loss) from discontinued operations (note 5)	20,871	(391)	—	(39)
Net income (loss) and comprehensive income (loss)	23,885	3,093	(2,218)	(2,247)
Net (income) loss and comprehensive (income) loss attributable to non-controlling interest	(13)	11	(3)	9
Net income (loss) and comprehensive income (loss) attributable to shareholders	23,872	3,104	(2,221)	(2,238)
Basic earnings (loss) per common share: (note 8)				
From continuing operations	0.74	0.90	(0.61)	(0.63)
From discontinued operations	5.59	(0.11)	—	(0.01)
	6.33	0.79	(0.61)	(0.64)
Diluted earnings (loss) per common share: (note 8)				
From continuing operations	0.72	0.88	(0.61)	(0.63)
From discontinued operations	5.49	(0.11)	—	(0.01)
	6.21	0.77	(0.61)	(0.64)

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)	September 30 2011	December 31 2010
ASSETS		
Current assets:		
Cash and cash equivalents <i>(note 15)</i>	1,051	1,301
Accounts receivable <i>(note 11)</i>	6,726	23,016
Gas purchase variance recoverable	2,666	4,498
Income taxes recoverable	—	1,305
Inventories of natural gas and supplies	684	764
Prepaid expenses	1,563	1,056
Future income taxes	32	468
Current assets of discontinued operations <i>(note 5)</i>	—	594
	12,722	33,002
Plant, property and equipment	199,618	196,176
Intangible assets	1,741	1,766
Regulatory and other assets	15,648	17,659
Long-term assets of discontinued operations <i>(note 5)</i>	—	684
	229,729	249,287
LIABILITIES		
Current liabilities:		
Bank indebtedness	2,308	4,836
Accounts payable and accrued liabilities	14,045	18,909
Income taxes payable	907	—
Other taxes payable	1,635	3,388
Derivative financial instruments <i>(note 10)</i>	2,626	5,696
Long-term debt, current	8,214	8,192
Current liabilities of discontinued operations <i>(note 5)</i>	—	197
	29,735	41,218
Long-term debt, non-current	75,106	82,761
Regulatory and other liabilities	9,344	10,892
Future income taxes	20,649	20,099
	134,834	154,970
EQUITY		
Preferred shares	5,000	5,000
Common shares <i>(note 9)</i>	9,465	9,038
Contributed surplus	6,884	4,515
Retained earnings	73,244	75,490
Total shareholders' equity	94,593	94,043
Non-controlling interest	302	274
	94,895	94,317
	229,729	249,287

Commitments *(note 13)*
Subsequent event *(note 17)*

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 EQUITY
(Unaudited)

(\$ in thousands)	For the nine months ended September 30		For the three months ended September 30	
	2011	2010	2011	2010
Preferred shares				
Balance, beginning and end of period	5,000	5,000	5,000	5,000
Common shares				
Balance, beginning of period	9,038	8,890	9,462	9,005
Employee share options exercised	427	134	3	19
Balance, end of period	9,465	9,024	9,465	9,024
Contributed surplus				
Balance, beginning of period	4,515	3,699	6,841	4,286
Share option expense	84	79	16	16
Employee share options exercised	2,285	642	27	118
Balance, end of period	6,884	4,420	6,884	4,420
Retained earnings				
Balance, beginning of period	75,490	72,847	76,602	76,008
Net income (loss) attributable to shareholders	23,872	3,104	(2,221)	(2,238)
Dividends – preferred shares	(169)	(169)	—	—
Dividends – common shares	(25,949)	(3,025)	(1,137)	(1,013)
Balance, end of period	73,244	72,757	73,244	72,757
Total shareholders' equity, end of period	94,593	91,201	94,593	91,201
Non-controlling interest				
Balance, beginning of period	274	—	283	230
Contribution from non-controlling interest	28	232	16	—
Distribution to non-controlling interest	(13)	—	—	—
Net income (loss) attributable to non-controlling interest	13	(11)	3	(9)
Balance, end of period	302	221	302	221
Total equity, end of period	94,895	91,422	94,895	91,422

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
(Unaudited)

(\$ in thousands)	For the nine months ended September 30		For the three months ended September 30	
	2011	2010	2011	2010
OPERATING ACTIVITIES				
Net income (loss) attributable to shareholders	23,872	3,104	(2,221)	(2,238)
(Income) loss from discontinued operations	(20,871)	391	—	39
	3,001	3,495	(2,221)	(2,199)
Add (deduct) items not involving cash:				
Future income taxes (note 7)	992	2,268	649	(80)
Depreciation and amortization	4,249	6,480	1,399	2,199
Amortization of termination payment deferral	(1,264)	—	(423)	—
Share-based compensation	358	402	20	82
Imputed interest on regulatory assets and liabilities	211	168	67	8
Other	71	(93)	23	(174)
	7,618	12,720	(486)	(164)
Changes in operating assets and liabilities (note 15)	5,504	(8,007)	(834)	(3,680)
Net cash provided by (used in) operating activities of continuing operations	13,122	4,713	(1,320)	(3,844)
Net cash (used in) provided by operating activities of discontinued operations	(2,856)	243	—	229
Net cash provided by (used in) operating activities	10,266	4,956	(1,320)	(3,615)
INVESTING ACTIVITIES				
Additions to plant, property and equipment	(6,188)	(4,771)	(3,592)	(2,210)
Increase in restricted cash	(319)	—	(6)	—
Acquisition, net of cash acquired	—	(7,657)	—	(328)
Other	(105)	—	—	—
Net cash used in investing activities of continuing operations	(6,612)	(12,428)	(3,598)	(2,538)
Net cash provided by (used in) investing activities of discontinued operations	29,706	(770)	—	(224)
Net cash provided by (used in) investing activities	23,094	(13,198)	(3,598)	(2,762)
FINANCING ACTIVITIES				
Increase (decrease) in bank indebtedness	(2,528)	1,644	2,308	4,223
Issue of long term debt, net of financing costs	—	9,885	—	4,000
Repayment of long-term debt	(7,691)	(752)	(6,899)	(692)
Employee stock options exercised	2,712	776	30	137
Dividends paid	(26,118)	(3,194)	(1,137)	(1,013)
Net contributions from non-controlling interest	15	232	16	—
Net cash (used in) provided by financing activities of continuing operations	(33,610)	8,591	(5,682)	6,655
Increase (decrease) in cash from continuing operations	(27,100)	876	(10,600)	273
Increase (decrease) in cash from discontinued operations	26,850	(527)	—	5
Increase (decrease) in cash and cash equivalents	(250)	349	(10,600)	278
Cash and cash equivalents, beginning of period	1,301	1,480	11,651	1,551
Cash and cash equivalents, end of period	1,051	1,829	1,051	1,829

Supplemental cash flow information (note 15)

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 and nine months ended September 30, 2011
(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.

As part of a business strategy to diversify the Company’s risk profile, grow its asset base and enhance its earnings and cash flows, the Company entered the renewable power business in April 2010 with the acquisition of a 97.1% interest in the McNair Creek 9.8 megawatt ‘run of river’ hydro-electricity generation facility located on British Columbia’s Sunshine Coast. McNair Creek is a non-regulated business and currently operates under a long-term supply agreement with BC Hydro.

The Company’s diversification into the renewable power business has continued in 2011, with the establishment of the Narrows Inlet Limited Partnership in which the Company has a 98% interest. In April 2011, this limited partnership entered into an arrangement to co-develop the proposed 45 megawatt Narrows Inlet run-of-river renewable energy project consisting of five proposed developments situated on four creeks that are located within a radius of 5 to 7 km of each other at the northern end of Narrows Inlet, which is located approximately 35 km north of the town of Sechelt, British Columbia. The Narrows Inlet Project will benefit from coastal precipitation patterns, some storage capacity and close proximity to the largest electricity load center in British Columbia. The Narrows Inlet Project was awarded a 30-year energy purchase agreement with BC Hydro in the spring of 2010.

On March 2, 2011, the Company completed the sale of its interest in both Pacific Trail Pipelines Limited Partnership and its general partner, Pacific Trail Pipelines Management Inc. In accordance with the accounting standard for discontinued operations, the results of operations related to those dispositions have been excluded from continuing operations and are reported as discontinued operations for all periods presented in these financial statements (see note 5).

2. BASIS OF PRESENTATION

These interim consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”) as specified in Part V of the Canadian Institute of Chartered Accountants (“CICA”) Handbook (see note 4), 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, 2010.

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, 2010.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three and nine months ended September 30, 2011
(Unaudited)

2. BASIS OF PRESENTATION (continued)

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.

All financial figures are presented in Canadian dollars.

3. PRINCIPLES OF CONSOLIDATION

These interim consolidated financial statements include the accounts of the Company, its wholly-owned subsidiary, PNG (N.E.), the accounts of McNair Creek Hydro Limited Partnership (“McNair Creek”) and Narrows Inlet Limited Partnership (“Narrows Inlet”) and the associated non-controlling interest, as well as the Company’s proportionate share of its 50% investment in the assets, liabilities, revenues and expenses of both Pacific Trail Pipelines Limited Partnership and Pacific Trail Pipelines Management Inc., until their disposal on March 2, 2011, as disclosed in note 5 and presented as discontinued operations.

These interim consolidated financial statements include the results of operations, cash flows, financial position and non-controlling interest of McNair Creek from the date of acquisition, April 19, 2010, and of Narrows Inlet from the date of formation, April 13, 2011.

All intercompany transactions and balances are eliminated.

4. ACCOUNTING CHANGES

Changes applied in 2011

2011 REVENUE REQUIREMENTS APPLICATION CHANGES

Effective January 1, 2011, the Company adopted the following new accounting policies and changes in accounting estimates on a prospective basis in accordance with its 2011 revenue requirements applications filed with the Commission. These changes in depreciation, capitalization of overheads and accounting for non-pension post-retirement benefits were accepted under negotiated settlements reached on April 27, 2011. The Commission approved the settlements in May 2011.

Depreciation of plant and equipment is recorded on a straight-line basis over the underlying assets’ useful lives. Effective January 1, 2011, the Company implemented the recommendations of a recently completed depreciation study which resulted in adjustments to the estimated remaining useful lives of plant and equipment assets. For 2011, these changes are expected to result in a net decrease in depreciation expense of approximately \$2 million.

Other changes as reflected in the Company’s 2011 revenue requirements applications include a reduction in the pool of overhead costs subject to capitalization as part of the cost of self-constructed plant and equipment, and the inclusion in rates of the full actuarially-determined expense for non-pension post-employment benefit plans. As noted, these changes were adopted on a prospective basis, however, they are not expected to impact net earnings due to their inclusion in the 2011 approved rates.

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4. ACCOUNTING CHANGES (continued)

CANADIAN ACCOUNTING STANDARD CHANGES

Financial Instruments – Recognition and Measurement

In June 2009, the CICA provided a clarification to Handbook Section 3855, *Financial Instruments – Recognition and Measurement*, with respect to the embedded prepayment option. The Section has been amended to clarify when an embedded prepayment option is separated from its host instrument for accounting purposes. The amendment states that if the exercise price of a prepayment option compensates the lender for an amount equivalent to the present value of the lost interest for the remaining term of the host instrument, the feature is considered closely related to the host contract in which it is embedded. The amendment applies to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The adoption of the amendments to Section 3855 had no effect on the Company's consolidated financial statements.

Comprehensive Revaluation of Assets and Liabilities

In August 2009, the CICA amended Handbook Section 1625, *Comprehensive Revaluation of Assets and Liabilities*, as a result of issuing Sections 1582, *Business Combinations*, 1601, *Consolidated Financial Statements*, and 1602, *Non-Controlling Interests*, in January 2009. The amendments require that when push-down accounting is used following the acquisition of an enterprise, the assets and liabilities are to be measured at the values used in accounting for the purchase transaction or transactions in accordance with Section 1582. The amendments also require that, when a future income tax asset that arose prior to the date of a comprehensive revaluation and that was not recognized in the comprehensive revaluation is subsequently recognized; the benefit should be recognized in accordance with Section 1582 and Section 3465, *Income Taxes*. The amendments apply prospectively to comprehensive revaluations of assets and liabilities occurring in fiscal years beginning on or after January 1, 2011. The adoption of the amendments to Section 1625 had no effect on the Company's consolidated financial statements.

Multiple Deliverable Revenue Arrangements

In December 2009, the CICA issued EIC-175, *Multiple Deliverable Revenue Arrangements*, replacing EIC-142, *Revenue Arrangements with Multiple Deliverables*. The changes were made in response to changes made to Accounting Standards Codification Topic 605-25, *Revenue Recognition – Multiple Element Arrangements*, under United States ("US") GAAP, and more closely aligns the accounting requirements for multiple-element arrangements under Canadian GAAP and with US GAAP and IFRS. EIC-175 addresses how to determine whether an arrangement involving multiple deliverables contains more than one accounting unit and, if so, how the consideration specified in the multiple element arrangement should be distributed between different accounting units. These recommendations are to be applied prospectively to revenue arrangements with multiple deliverables entered into or materially modified in the first annual fiscal period beginning on or after January 1, 2011. The adoption of EIC-175 had no effect on the Company's consolidated financial statements.

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4. ACCOUNTING CHANGES (continued)

Future accounting pronouncements

NEW ACCOUNTING STANDARDS

The Canadian Accounting Standards Board (“AcSB”) had determined that publicly accountable enterprises would be required to prepare financial statements in accordance with IFRS for years beginning on or after January 1, 2011. However, in October 2010, the AcSB issued an amendment to Part I of the CICA Handbook allowing for a one-year deferral for first-time adoption of IFRS for qualifying entities with rate-regulated activities. The Canadian Securities Administrators’ regulations have also been amended to incorporate the AcSB’s one-year deferral. As previously disclosed, the Company meets the requirements of a qualifying entity and elected to take the optional one-year deferral.

The Company’s 2011 financial statements are prepared according to Part V of the CICA Handbook which was Canadian GAAP prior to the changeover to IFRS. Both Part V of the CICA Handbook and US GAAP allow the use of rate-regulated accounting and the recognition of regulatory assets and liabilities that are recovered or settled through future rates in a regulated entity’s financial statements. Currently, IFRS does not allow the recognition of regulatory assets and liabilities and there continues to be significant uncertainty as to when, and if, IFRS will readdress rate-regulated accounting.

Recently, certain Canadian securities commissions have issued exemption orders that enable qualified non-Securities and Exchange Commission (“SEC”) issuers with “activities subject to rate regulation” to file their financial statements in accordance with US GAAP for the years commencing on or after January 1, 2012 but before January 1, 2015. Without this exemption order, an entity would be required to be an SEC registrant in order to file its financial statements under US GAAP. Many Canadian regulated utilities have been granted exemptive relief from security regulators and will be filing their financial statements based on US GAAP commencing 2012.

The Company believes that US GAAP, which allows rate-regulated accounting, better represents and reflects the Company’s financial position and results of its regulated business, and plans to adopt US GAAP effective January 1, 2012. The Company has obtained all necessary approvals, including the required exemption order from the British Columbia and Ontario Securities Commissions issued on August 18, 2011, and the required order from the British Columbia Utilities Commission permitting the use of US GAAP for regulatory filings issued on October 7, 2011.

5. DISCONTINUED OPERATIONS

On March 2, 2011, the Company completed the sale of its 50% joint venture interests in both Pacific Trail Pipelines Limited Partnership and Pacific Trail Pipelines Management Inc. (collectively “PTP”). These entities were established to develop a proposed 463 kilometre natural gas pipeline in central British Columbia, from Summit Lake to Kitimat (“KSL Project”). The Company’s interests in the KSL Project were purchased by its partners in the project, Apache Canada Ltd. and EOG Resources Canada Inc.

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5. DISCONTINUED OPERATIONS (continued)

The sale transaction has two components, the first being a cash payment of \$30.4 million that the Company received on closing, and the second being a cash payment of \$20.0 million to be paid contingent on the purchasers making a decision to proceed with construction of a liquefied natural gas (“LNG”) facility in Kitimat. The Company has recorded initial sales proceeds of \$30.4 million on this transaction, and a resulting pre-tax gain of \$23.4 million in the consolidated statements of income for 2011, net of \$5.2 million in transaction costs incurred in connection with the sale, including management incentive compensation of \$4.0 million and professional advisory fees and other related costs of \$1.2 million, and \$0.7 million in project expenses incurred prior to the disposition. The Company recorded a related income tax provision of \$2.6 million, resulting in net income from discontinued operations of \$20.9 million for the nine month period ended September 30, 2011.

On March 3, 2011, the Company’s Board of Directors declared a special dividend of \$3.00 per common share, which represented approximately \$11 million of the proceeds from the sale of PTP. On May 11, 2011, the Company’s Board of Directors declared an additional special dividend of \$3.00 per common share, which represented an additional \$11 million of the remaining proceeds.

The Company can give no assurances that construction of the Kitimat LNG facility will be completed or that the contingent \$20.0 million payment will be made. This amount will be recognized in the consolidated statements of income when the contingency is resolved.

The gain on disposal and results of operations of discontinued operations are as follows:

Gain on disposal

(\$ in thousands)	September 30 2011
Proceeds from sale	30,388
Net book value	(1,027)
Transaction costs	(5,192)
Gain on disposal	24,169

Results of operations

(\$ in thousands)	For the nine months ended September 30		For the three months ended September 30	
	2011	2010	2011	2010
Gain on disposal	24,169	—	—	—
Project expenses	(738)	(556)	—	(27)
Income (loss) before income taxes	23,431	(556)	—	(27)
Income tax (expense) recovery	(2,560)	165	—	(12)
Net income (loss) and comprehensive income (loss) from discontinued operations	20,871	(391)	—	(39)

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6. EMPLOYEE FUTURE BENEFITS

During the three and nine months ended September 30, 2011, the Company recorded pension and other post-employment benefit expenses of \$0.5 million and \$1.5 million, respectively (three and nine months ended September 30, 2010 – \$0.3 million and \$0.9 million, respectively).

7. INCOME TAX EXPENSE (RECOVERY)

(\$ in thousands)	For the nine months ended September 30		For the three months ended September 30	
	2011	2010	2011	2010
Current income tax expense (recovery)	(446)	(1,339)	(1,618)	(1,119)
Future income tax expense (recovery)	992	2,268	649	(80)
	546	929	(969)	(1,199)

8. EARNINGS (LOSS) PER COMMON SHARE

(\$ in thousands, except share and per share amounts)	For the nine months ended September 30		For the three months ended September 30	
	2011	2010	2011	2010
Net income (loss) from continuing operations	3,014	3,484	(2,218)	(2,208)
Net income (loss) from discontinued operations	20,871	(391)	—	(39)
Net income (loss)	23,885	3,093	(2,218)	(2,247)
Net (income) loss attributable to non-controlling interest	(13)	11	(3)	9
Dividends on preferred shares	(253)	(253)	(84)	(84)
Net income (loss) attributable to common shares	23,619	2,851	(2,305)	(2,322)
Basic weighted-average number of shares outstanding	3,730,134	3,593,975	3,785,351	3,608,037
Effect of dilutive securities:				
Share options	73,930	90,400	—	—
Diluted weighted-average number of shares outstanding	3,804,064	3,684,375	3,785,351	3,608,037
Basic earnings (loss) per common share:				
From continuing operations	0.74	0.90	(0.61)	(0.63)
From discontinued operations	5.59	(0.11)	—	(0.01)
	6.33	0.79	(0.61)	(0.64)
Diluted earnings (loss) per common share:				
From continuing operations	0.72	0.88	(0.61)	(0.63)
From discontinued operations	5.49	(0.11)	—	(0.01)
	6.21	0.77	(0.61)	(0.64)

Pacific Northern Gas Ltd.
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8. EARNINGS (LOSS) PER COMMON SHARE (continued)

For the nine month periods ended September 30, 2011 and September 30, 2010, no share options have been excluded from the computation of diluted weighted-average number of shares outstanding because the exercise price for all outstanding share options was lower than the average market price of the Company's common shares during these periods.

For the three months ended September 30, 2011, 48,954 share options (three months ended September 30, 2010 – 104,340) have been excluded from the computation of diluted weighted-average number of shares outstanding because the Company reported a loss from continuing operations and therefore including these share options would have an anti-dilutive effect on earnings per share.

9. COMMON SHARES OUTSTANDING

	Number of shares
Balance, December 31, 2009	3,555,964
Issue of shares under share option plan	59,180
Balance, December 31, 2010	3,615,144
Issue of shares under share option plan	170,960
Balance, September 30, 2011	3,786,104

During the three and nine months ended September 30, 2011, the Company issued 1,300 and 170,960 common shares, respectively, on the exercise of share options (2010 – 7,320 and 53,520, respectively).

10. FINANCIAL INSTRUMENTS

Financial instruments by category

The fair value of the Company's financial instruments, including derivatives, reflects point-in-time estimates 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)	September 30, 2011		December 31, 2010	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Held for trading				
Cash and cash equivalents	1,051	1,051	1,301	1,301
Loans and receivables				
Accounts receivable	6,726	6,726	23,016	23,016
Other financial liabilities				
Bank indebtedness	2,308	2,308	4,836	4,836
Accounts payable and accrued liabilities	14,045	14,045	18,909	18,909
Long-term debt, including current portion	83,320	97,245	90,953	100,735

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10. FINANCIAL INSTRUMENTS (continued)

The fair values of financial instruments included in current assets and current liabilities in the Company's interim consolidated balance sheets approximate their carrying value, reflecting the short-term maturity of these instruments. The fair value of each of the Company's long-term debt instruments is estimated by using a discounted cash flow calculation, with the discount rate being the current market yield on an appropriate Government of Canada debt instrument adjusted for an estimate of the Company's credit risk premium.

Derivative financial instruments

The Company has historically hedged exposures to fluctuations in natural gas prices through the use of derivative financial instruments. The Company has two hedge lines of credit, each secured by the pledge of a \$20.0 million debenture. One line is with the provider of the Company's bank operating line and the other is with another Canadian bank. Under either hedge line if the credit exposure of the provider exceeds \$20.0 million, the Company is required to provide cash collateral to the extent of the excess credit exposure.

These 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. The Company has not entered into any new hedging arrangements since February 2011. In July 2011 the Company withdrew its 2011 price risk management plan from consideration by the Commission and ceased its program to hedge natural gas purchases. Existing hedges will expire by October 2012.

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 September 30, 2011

Financial instrument	Notional quantity (gigajoules)	Percent of annual gas purchases (%)	Delivery period	Price range (per gigajoule)	Estimated net fair value payable ((\$000's))
Natural gas swap contracts	2 538 000	28.7	Oct 2011 – Oct 2012	\$3.94 - \$6.49	(2,765)
Collar contracts	53 500	0.6	Apr 2012 – Oct 2012	\$3.80 (floor) - \$5.31 (cap)	(21)
	2 591 500	29.3			(2,786)

Of the \$2.8 million liability as at September 30, 2011, \$2.6 million is recorded as a current liability and \$0.2 million is recorded in non-current regulatory and other liabilities on the interim consolidated balance sheet.

As at December 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))
Fixed-price contracts	900 000	9.4	Jan 2011 – Mar 2011	\$4.23	(678)
Natural gas swap contracts	3 846 600	40.2	Jan 2011 – Oct 2012	\$4.16 to \$7.26	(5,453)
Collar contracts	53 500	0.6	Apr 2012 – Oct 2012	\$3.80 (floor) - \$5.31 (cap)	(8)
	4 800 100	50.2			(6,139)

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10. FINANCIAL INSTRUMENTS (continued)

Of the \$6.1 million net liability at December 31, 2010, \$0.1 million is recorded as a current asset, \$5.7 million is recorded as a current liability and \$0.5 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 would be treated as part of the cost of gas.

The Company's derivative financial instruments are classified as Level 2 within the fair value hierarchy. The Company uses valuation models to determine the fair value of its derivative financial instruments relying on external observable inputs such as natural gas forward prices.

11. RISK MANAGEMENT

Credit risk

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

(\$ in thousands)	September 30 2011	December 31 2010
Core market – residential and commercial	6,769	19,581
Industrial customers	608	779
Off-system sales customers	—	3,167
Other	225	338
	7,602	23,865
Less: Allowance for doubtful accounts	(876)	(849)
	6,726	23,016

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

(\$ in thousands)	September 30 2011	December 31 2010
Unbilled revenues	2,427	11,991
Past due 0 to 30 days (current)	4,179	11,119
Past due 31 to 90 days	339	303
Past due over 91 days	657	452
	7,602	23,865
Less: Allowance for doubtful accounts	(876)	(849)
	6,726	23,016

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11. RISK MANAGEMENT (continued)

Changes in the allowance for doubtful accounts are as follows:

(\$ in thousands)	September 30 2011	December 31 2010
Balance, beginning of period	849	2,044
Provision for doubtful accounts	—	265
Write-off of bad debts and other	27	(1,460)
Balance, end of period	876	849

Liquidity risk

The Company's overall liquidity risk has improved slightly from December 31, 2010, primarily due to the net proceeds received on the sale of PTP, less special dividends paid out in 2011 (see note 5).

As at September 30, 2011, the Company had utilized \$4.9 million of its \$25.0 million operating line facility to fund working capital requirements and to issue letters of credit and had utilized \$10.0 million of the \$35.0 million available under its revolving term facility. The Company also has cash and cash equivalents of \$1.0 million.

12. CAPITAL MANAGEMENT

The Company's capital is summarized as follows:

(\$ in thousands)	September 30 2011	December 31 2010
Bank indebtedness	2,308	4,836
Long-term debt	83,320	90,953
Less: cash and cash equivalents	(1,051)	(1,301)
Net debt	84,577	94,488
Shareholders' equity	94,593	94,043
Balance, end of period	179,170	188,531

Certain capital requirements are contained in the terms and conditions of the Company's debentures and credit facilities. These financial terms and conditions remain unchanged since December 31, 2010.

On June 10, 2011 Dominion Bond Rating Services ("DBRS") confirmed the Company's secured debt ratings at BBB (low). The Company is presently in compliance with its debt covenants, and was in compliance during the reporting periods under review.

Pacific Northern Gas Ltd.
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13. COMMITMENTS

The Company has long- and short-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 September 30, 2011 under various gas supply and transportation services contracts expiring through 2017 were as follows:

(\$ in thousands)

2011	9,897
2012	15,735
2013	812
2014	812
2015	760
2016	462
2017	209
Total	28,687

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 September 30, 2011.

As determined by the actuarial valuation report as at December 31, 2009, completed during the third quarter of 2010, the Company is required to make annual funding contributions of \$2.2 million to its pension plan in 2011 and \$2.0 million in 2012.

The Company has a commitment to invest up to \$2.5 million to advance the Narrows Inlet Project to the commencement-of-construction stage which is expected to be achieved by late 2012. As at September 30, 2011, the Company had invested approximately \$1.7 million towards this obligation.

14. SEGMENTED INFORMATION

The Company operates in two business segments: the transmission and distribution of natural gas and the generation and sale of electricity from renewable resources. The renewable energy segment includes the operations of McNair Creek, as well as Narrows Inlet and other renewable development activities. The Company operates in a single geographic segment: Canada.

The segment information does not include the results of business classified as discontinued operations.

The following tables provide segmented financial information for the three and nine month periods ended September 30, 2010 and 2011.

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14. SEGMENTED INFORMATION (continued)

(\$ in thousands)	For the nine months ended September 30, 2011			For the nine months ended September 30, 2010		
	Gas Transmission and Distribution	Renewable Energy	Consolidated	Gas Transmission and Distribution	Renewable Energy	Consolidated
Revenues	57,031	1,650	58,681	64,293	790	65,083
Cost of gas	24,513	—	24,513	30,056	—	30,056
	32,518	1,650	34,168	34,237	790	35,027
Operating and maintenance	9,799	159	9,958	9,047	102	9,149
Administrative and general	6,968	180	7,148	5,663	754	6,417
Development costs	—	443	443	—	287	287
Depreciation and amortization	3,885	364	4,249	6,309	171	6,480
Municipal and other taxes	3,630	78	3,708	3,519	47	3,566
	24,282	1,224	25,506	24,538	1,361	25,899
Finance fees	8,236	426	8,662	9,699	(571)	9,128
Income tax expense (recovery)	4,582	520	5,102	4,388	327	4,715
	594	(48)	546	1,073	(144)	929
Net income (loss) from continuing operations	3,060	(46)	3,014	4,238	(754)	3,484
Capital expenditures	5,216	972	6,188	4,767	4	4,771

(\$ in thousands)	For the three months ended September 30, 2011			For the three months ended September 30, 2010		
	Gas Transmission and Distribution	Renewable Energy	Consolidated	Gas Transmission and Distribution	Renewable Energy	Consolidated
Revenues	8,435	496	8,931	9,473	209	9,682
Cost of gas	2,185	—	2,185	3,088	—	3,088
	6,250	496	6,746	6,385	209	6,594
Operating and maintenance	3,328	74	3,402	2,876	102	2,978
Administrative and general	2,134	37	2,171	1,672	157	1,829
Development costs	—	119	119	—	118	118
Depreciation and amortization	1,276	123	1,399	2,102	97	2,199
Municipal and other taxes	1,211	26	1,237	1,173	26	1,199
	7,949	379	8,328	7,823	500	8,323
Finance fees	(1,699)	117	(1,582)	(1,438)	(291)	(1,729)
Income tax expense (recovery)	1,435	170	1,605	1,498	180	1,678
	(926)	(43)	(969)	(1,110)	(89)	(1,199)
Net income (loss) from continuing operations	(2,208)	(10)	(2,218)	(1,826)	(382)	(2,208)
Capital expenditures	3,003	589	3,592	2,206	4	2,210

Pacific Northern Gas Ltd.
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14. SEGMENTED INFORMATION (continued)

Other segment information regarding assets and liabilities is as follows:

As at September 30, 2011

(\$ in thousands)	Gas Transmission and Distribution	Renewable Energy	Consolidated
Plant, property & equipment	179,374	20,244	199,618
Assets	207,311	22,418	229,729
Liabilities	121,789	13,045	134,834

As at December 31, 2010

(\$ in thousands)	Gas Transmission and Distribution	Renewable Energy	Consolidated
Plant, property & equipment	177,044	19,132	196,176
Assets	226,838	21,171	248,009
Liabilities	142,397	12,376	154,773

15. SUPPLEMENTAL CASH FLOW INFORMATION

(\$ in thousands)	September 30 2011	December 31 2010
Cash and cash equivalents:		
Cash	1,051	1,301
Cash equivalents	—	—
	1,051	1,301

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
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15. SUPPLEMENTAL CASH FLOW INFORMATION (continued)

(\$ in thousands)	For the nine months		For the three months	
	ended September 30		ended September 30	
	2011	2010	2011	2010
Changes in operating assets and liabilities:				
(Increase) decrease in:				
Accounts receivable	16,290	15,057	2,534	(2,066)
Income taxes recoverable	1,305	(3,543)	—	(1,717)
Gas purchase variance recoverable	(1,551)	—	(594)	—
Prepaid expenses and other	(507)	(49)	(292)	(918)
Inventories of supplies and natural gas	80	467	(366)	175
Increase (decrease) in:				
Accounts payable and accrued liabilities	(8,607)	(11,269)	1,769	3,820
Other taxes payable	(1,759)	(1,841)	(2,794)	(2,272)
Income taxes payable	(1,658)	(1,041)	(715)	—
Gas purchase variance payable	—	(930)	—	358
Changes in regulatory assets and liabilities	2,394	(3,845)	(224)	(277)
Contributions to defined benefit plans in excess of expense	(483)	(1,013)	(152)	(783)
Attributable to operating activities	5,504	(8,007)	(834)	(3,680)
Cash interest and tax payments:				
Interest paid	4,385	3,877	1,195	1,151
Income taxes paid	1,308	3,069	498	573

16. COMPARATIVE FIGURES

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

17. SUBSEQUENT EVENT

On October 30, 2011, the Company entered into a definitive agreement under which AltaGas Ltd. ("AltaGas") has agreed to acquire all of the issued and outstanding shares of the Company for \$230 million, including assumed debt.

The proposed transaction will proceed by way of a court-approved statutory plan of arrangement, the implementation of which is subject to approval by 66 2/3% of the votes cast by shareholders at a special meeting to be held on or about December 12, 2011, and by a majority of the 'minority' shareholders voting at the meeting. The proposed transaction is also subject to a number of other customary closing conditions, including regulatory approval by the Commission. If approved, the transaction is expected to close on or about December 13, 2011. Under certain specified circumstances, such as where PNG enters into a definitive agreement with respect to a superior proposal, a termination fee of \$5 million is payable by PNG to AltaGas.

**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 report and interim MD&A (together, the “interim filings”) of Pacific Northern Gas Ltd., (“the issuer”) for the interim period ended September 30, 2011.
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 report together with the other financial information included in the interim filings fairly present in all material respects the financial condition, financial performance and cash flows of the issuer, as of the date of 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 July 1, 2011 and ended on September 30, 2011 that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

Date: November 4, 2011

"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 report and interim MD&A (together, the “interim filings”) of Pacific Northern Gas Ltd., (“the issuer”) for the interim period ended September 30, 2011.
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 report together with the other financial information included in the interim filings fairly present in all material respects the financial condition, financial performance 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 July 1, 2011 and ended on September 30, 2011 that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

Date: November 4, 2011

"Janet Kennedy"

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