



# **Interim Report**

**For the Three and Six Months Ended June 30, 2011**

**July 29, 2011**

Pacific Northern Gas Ltd.  
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# **PACIFIC NORTHERN GAS LTD. MANAGEMENT'S DISCUSSION AND ANALYSIS June 30, 2011**

***Date: July 29, 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 six months ended June 30, 2011. It should also be read in conjunction with the audited consolidated financial statements of Pacific Northern Gas Ltd. ("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](http://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 timing and results of regulatory decisions, including with respect to future revenue requirements applications (see "Regulatory Activities");
- 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 the potential LNG Partners LLC ("LNG Partners") small scale liquefied natural gas ("LNG") project and the cost of reactivating compressor stations to provide such service (see "Business Overview – Capacity Utilization on the Western System");
- 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”);
- The competitiveness of retail gas rates relative to electricity rates (see “Business Overview - Competitiveness of Rates”);
- The trends in customer numbers in the Western and Northeastern service areas;
- The required levels of pension funding and the fair value of pension assets;
- The renewal of franchise and operating agreements;
- The level of and source of funding for capital expenditure requirements; and
- The impact of climate change initiatives on the Company’s performance.

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;
- 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 transition to new accounting standards. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this MD&A or otherwise, and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by applicable securities laws.

### ***Non-GAAP Measures***

References to "operating margin" are to 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.

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

The Company 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 mid-to-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 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 facility.

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 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 and 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 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.

While there can be no assurance that the favourable trend will continue, or that any LNG projects will actually be developed, PNG is aware of recent progress made with regard to

the LNG Partners small scale LNG export project. The Company and LNG Partners are parties to a Commission approved transportation service agreement (“TSA”) that provides a capacity option of 80 MMcf per day. 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, it would utilize the transportation service to deliver natural gas to an LNG facility to be located on the Douglas Channel near Kitimat, B.C. LNG Partners expects that the LNG produced at this facility would be exported to LNG markets in Asia. During the first quarter of 2011, BC LNG Export Co-operative LLC an affiliate of LNG Partners, applied to the National Energy Board (“NEB”) for permission to export LNG. According to the application, BC LNG Export Co-operative is a 50:50 partnership between LNG Partners and the Haisla Nation Douglas Channel LNG Limited Partnership. On July 25, 2011 the National Energy Board issued an order setting out the terms of reference for a public hearing into the application.

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 another \$1 million by December 31, 2011.

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 operations in 2005 will be recovered from these incremental revenues. The reactivation costs are in the range of \$1.3 million with the largest single expense being the cost of completing a compressor overhaul at an estimated cost of \$0.5 million. For regulatory purposes, the Company anticipates expensing all reactivation costs in the first year of operation. 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. The Company expects the full \$1 million reduction will occur as the LNG export licence application by BC LNG Export Co-operative to the NEB states that LNG sales are anticipated to commence in the fourth quarter of 2013. If service does not commence by January 1, 2015 then the TSA would terminate and the Company would retain all option fees.

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 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 June 30, 2011, the Company has invested \$0.9 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.

Partnering with Skookum Power Holdings Corp., as it did on the McNair Creek facility, allows the Company to gain 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. Construction is expected to commence in mid/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 if NILP elects to proceed with funding construction. 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.

Conditions to construction include the receipt of the necessary environmental and construction permits required to commence construction, securing of contractor agreements to build the facility, and financing for construction of the Narrows Inlet Project. The Company can give no assurances that these conditions will be satisfied or that construction of the Narrows Inlet Project by NILP will proceed.

## **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. The termination payment will be amortized into earnings over the remaining life of the agreement as per the 2011 revenue requirements application negotiated settlement agreement. In addition, as was the case with the closure of the Methanex plant, 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 Province of British Columbia’s (the “Province”) Energy Plan, released in early 2007, calls for the Province to become self-sufficient in electricity by 2016 with all new generation capacity being carbon neutral and to use demand side management to curtail growing electricity consumption. These policy objectives have contributed to and are expected to result in higher electricity rates over the long term. The Province implemented a carbon tax on fossil fuel consumption effective July 1, 2008. The carbon tax on natural gas was just under \$0.50 per gigajoule (“GJ”) effective July 1, 2008, rising annually by approximately \$0.25 per GJ each July 1, to just under \$1.50 per GJ effective July 1, 2012. Notwithstanding the impacts of carbon tax on natural gas, the cessation of the Methanex termination payment credit amortization and the closure of the West Fraser Eurocan Kitimat paper mill in January 2010, the Company expects its retail gas rates will maintain their relative competitiveness with electricity rates as electricity rates are expected to rise over time to meet the Province’s energy policy objectives. 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. The competitiveness of gas relative to electricity was improved with a reduction in the gas supply cost recovery component of rates of \$0.72 per GJ effective April 1, 2011.

## **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.

Net loss for the three months ending June 30, 2011 was \$0.7 million, compared with a net loss of \$0.1 million for the corresponding period in 2010. After providing for preferred share dividends, the basic loss per common share for the three months ended June 30, 2011 was \$0.21 compared with a loss per common share of \$0.06 for the same period in 2010.

Net income from discontinued operations was \$0.05 million in the second quarter of 2011 composed of adjustments to taxes and transaction costs recognized on the sale of the KSL project compared to a net loss of \$0.15 million in the second quarter of 2010 for the Company's share of KSL project development expenses incurred.

Net loss from continuing operations for the three months ending June 30, 2011 was \$0.74 million compared to net income of \$0.005 million for the comparable period in 2010. The decrease in earnings from continuing operations is mainly due to the recognition of the 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 decreased the net loss in the second quarter of 2010. Excluding this amount, the loss from continuing operations due to the seasonality of the business for the second quarter of 2011 remained at similar levels as the prior year. The allowed weighted average ROE remains at 10.09 percent for 2011, the same as in 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 recorded in this deferral account, to be refunded to customers in future rates, an after-tax revenue variance of \$1.2 million for the six month period ended June 30, 2011.

## Natural Gas Volumes

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

*[Deliveries in TJ]*

<b>Three months ended June 30</b>	<b>Second Quarter 2011</b>	<b>Second Quarter 2010</b>	<b>% Change</b>
<b>Sales:</b>			
Residential	435	385	+13%
Commercial	323	336	(4%)
Small Industrial	63	85	(26%)
Large Industrial	-	-	-
<b>Total Sales</b>	<b>821</b>	806	+2%
<b>Transportation Service:</b>			
Commercial	65	44	+48%
Small Industrial	531	568	(7%)
Large Industrial	172	183	(6%)
<b>Total Transportation Service</b>	<b>768</b>	795	(3%)
<b>Total Deliveries</b>	<b>1 589</b>	1 601	(1%)
<b>Six months ended June 30</b>	<b>YTD June 30 2011</b>	<b>YTD June 30 2010</b>	<b>% Change</b>
<b>Sales:</b>			
Residential	1 784	1 531	+17%
Commercial	1 416	1 273	+11%
Small Industrial	216	219	(1%)
Large Industrial	-	-	-
<b>Total Sales</b>	<b>3 416</b>	3 023	+13%
<b>Transportation Service:</b>			
Commercial	205	133	+54%
Small Industrial	1 253	1 198	+5%
Large Industrial	437	662	(34%)
<b>Total Transportation Service</b>	<b>1 895</b>	1 993	(5%)
<b>Total Deliveries</b>	<b>5 311</b>	5 016	+6%

Residential deliveries were approximately 13 percent higher in the three months ended June 30, 2011 and 17 percent higher in the six months ended June 30, 2011. Total commercial deliveries were 2 percent higher for the three months ended June 30, 2011 and 15 percent higher for the six months ended June 30, 2011, relative to deliveries over the same periods in 2010. Management believes that weather was the key reason for higher deliveries as it was approximately 7 percent colder for the three month period ended June 30, 2011 and 15 percent colder for the six month period ended June 30, 2011 compared to the same periods in 2010. The weather was also 2 percent colder than normal for the three month period ended June 30, 2011 and 7 percent colder than normal, with “normal” based on the average of actual temperatures in the Company’s service areas for the preceding 10 years.

Industrial deliveries were lower by approximately 8 percent for the three month period and six month period ended June 30, 2011 compared to the same periods in 2010. The decrease in industrial deliveries is comprised of a 34 percent decrease in large industrial customer deliveries, mainly due to the closure of the West Fraser Kitimat liner board mill, combined with a 4 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. 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]*

<b>Continuing Operations</b>	<b>Gas Transmission and Distribution</b>	<b>Renewable Energy</b>	<b>Total</b>
<b>Three months ended June 30, 2011</b>			
Revenues	<b>\$11,558</b>	<b>\$713</b>	<b>\$12,271</b>
Operating margin	<b>8,302</b>	<b>713</b>	<b>9,015</b>
Net income (loss) from continuing operations	<b>(833)</b>	<b>95</b>	<b>(738)</b>
Three months ended June 30, 2010			
Revenues	\$14,585	\$ 581	\$15,166
Operating margin	9,955	581	10,536
Net income (loss) from continuing operations	134	(129)	5
<b>Six months ended June 30, 2011</b>			
Revenues	<b>\$48,596</b>	<b>\$1,154</b>	<b>\$49,750</b>
Operating margin	<b>26,268</b>	<b>1,154</b>	<b>27,422</b>
Net income from continuing operations	<b>5,268</b>	<b>36</b>	<b>5,232</b>
Six months ended June 30, 2010			
Revenues	\$54,820	\$ 581	\$55,401
Operating margin	27,852	581	28,433
Net income (loss) from continuing operations	5,943	(251)	5,692

## **Gas Transmission and Distribution**

Revenues in the three months ended June 30, 2011 were \$11.6 million compared with \$14.6 million in the same period in 2010. The \$3.0 million decrease reflected lower commodity costs in 2011 compared to 2010, the lower cost of service due mainly 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 second quarter of 2011 reflects the impact of higher deliveries to on system customers due to colder temperatures. Natural gas commodity prices are passed through to the Company’s sales customers without mark-up.

Revenues in the six months ended June 30, 2011 were \$48.6 million compared with \$54.8 million in the same period in 2010. The \$6.2 million decrease mainly reflected a reduction of \$4.7 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.

Operating margin in the three months ended June 30, 2011 decreased to \$8.3 million, as compared with \$10 million in the same period in 2010. For the six months ended June 30, 2011, operating margin also decreased to \$26.3 million as compared to \$27.9 million in the comparable period in 2010. The decrease of \$1.7 million for the quarter ended June 30, 2011 and \$1.6 million for the six months ended June 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 June 30, 2011, the McNair hydro-electric facility generated revenues of \$0.7 million compared to \$0.6 million in the comparable period in 2010. However, the 2010 results are not directly comparable to 2011 results since the McNair facility was not acquired until April 19, 2010. The Company recorded net after-tax earnings of approximately \$0.1 million from renewable energy operations for the three months ended June 30, 2011 compared to a net loss of \$0.1 million in the prior period. For the six months ended June 30, 2011, the McNair facility generated revenues of \$1.2 million and contributed approximately \$0.04 million to after-tax earnings of the Company. For the six months ended June 30, 2010, the McNair facility generated revenues of \$0.6 million and recorded a net loss of \$0.3 million. The higher earnings contribution reflects lower development expenses incurred during 2011 compared to 2010 when after-tax transaction costs of \$0.47 million were incurred for the McNair acquisition.

As described in the “Summary of Quarterly Results”, production from the McNair facility is seasonal. During the first six months of 2011, the McNair facility experienced slightly above average hydrologic conditions. As a result, electricity generation from the McNair facility for the six months ended June 30, 2011 was slightly in excess of the long-term average that was estimated using standard industry procedures.

## **2011 Revenue Requirements Applications**

Negotiated settlements of the Company’s 2011 revenue requirements applications were reached on April 27, 2011 between the Company and customer representatives in respect of all divisions. The Commission approved the negotiated settlement agreements on May 20, 2011. The Commission accepted in mid-June 2011 the gas tariff rate schedules prepared by the Company to reflect the rates agreed to under the approved settlement agreements.

The Western system settlement results in the applied for \$2.1 million revenue deficiency for 2011 declining to approximately \$0.5 million. Of this reduction, \$0.3 million reflects agreed to amendments to budgeted expenses, \$0.2 million is for an overall settlement allowance and \$0.5 million pertains to the sale of PTP. The majority of the balance of the reduction is due to increasing the forecast of deliveries to residential and small commercial customers (\$0.4 million) used for rate making purposes.

Under the Western system settlement the gas delivery rate increase for residential customers, effective January 1, 2011, compared to the corresponding delivery rate as of October 1, 2010, is approximately \$0.17 per GJ. This represents an annual bill increase of \$11 or 0.9 percent for the average residential customer consuming 66.7 GJ/year. The gas supply commodity rate decrease as of April 1, 2011 results in the annual gas bill for a typical residential customer being 2.9 percent lower compared to the annual bill using October 1, 2010 rates.

The Pacific Northern Gas (N.E.) Ltd. Fort St. John/Dawson Creek division’s settlement results in the applied for \$2.6 million revenue deficiency decreasing by \$0.4 million to \$2.2 million. The gas delivery rate increase for residential customers, effective January 1, 2011, compared to the corresponding delivery rate as of October 1, 2010, is \$0.74 per GJ. This represents an annual bill increase of \$80 or 8 percent for the average residential customer consuming 108 GJ/year. The gas supply commodity rate decrease as of April 1, 2011 results in the annual gas bill for a typical residential customer being virtually equal to the annual bill using October 1, 2010 rates. The PNG (N.E.) Tumbler Ridge division settlement results in the applied for \$0.05 million revenue deficiency decreasing by \$0.08 million to result in a modest revenue sufficiency of \$0.03 million.

The parties agreed the Company’s 2012 revenue requirements applications would be reviewed through an oral or written public hearing process given the last three applications were settled under negotiated settlement processes. Further, the Company agreed to file capital structure and return on equity evidence as part of its 2013 revenue requirements applications.

## 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>	Sept. 30, 2010	Dec. 31, 2010	Mar. 31, 2011	June 30, 2011
<b>Continuing Operations</b>				
Revenues	\$9,682	\$30,081	\$37,479	<b>\$12,271</b>
Net income (loss)	\$(2,193)	\$4,162	\$5,970	<b>\$(738)</b>
Earnings (loss) per common share – basic	\$(0.63)	\$1.15	\$1.61	<b>\$(0.22)</b>
Earnings (loss) per common share – diluted	\$(0.63)	\$1.11	\$1.57	<b>\$(0.22)</b>
<b>Total Operations</b> <sup>(1)</sup>				
Net income (loss)	\$(2,247)	\$3,984	\$26,793	<b>\$(690)</b>
Earnings (loss) per common share – basic	\$(0.64)	\$1.10	\$7.32	<b>\$(0.21)</b>
Earnings (loss) per common share – diluted	\$(0.64)	\$1.06	\$7.11	<b>\$(0.21)</b>

	Sept. 30, 2009	Dec. 31, 2009	Mar. 31, 2010	June 30, 2010
<b>Continuing Operations</b>				
Revenues	\$10,500	\$31,172	\$40,235	\$15,166
Net income (loss)	\$(1,645)	\$3,476	\$5,687	\$5
Earnings (loss) per common share – basic	\$(0.49)	\$0.96	\$1.57	\$(0.02)
Earnings (loss) per common share – diluted	\$(0.49)	\$0.94	\$1.53	\$(0.02)
<b>Total Operations</b> <sup>(1)</sup>				
Net income (loss)	\$(1,660)	\$3,436	\$5,488	\$(148)
Earnings (loss) per common share – basic	\$(0.49)	\$0.95	\$1.51	\$(0.06)
Earnings (loss) per common share – diluted	\$(0.49)	\$0.93	\$1.47	\$(0.06)

<sup>(1)</sup> 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% 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 June 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 June 30, 2011, the actual utilization of the operating line was \$2.6 million.

The risk management facilities are utilized by 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.

\$16.0 million was outstanding under the revolving term facility at June 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 June 30, 2011 of \$11.7 million were \$10.3 million higher than at December 31, 2010, mainly due to the net proceeds received from the sale of the Company's interest in PTP. Accounts receivable at June 30, 2011 were \$13.7 million lower than at December 31, 2010, mainly due to lower gas sales revenues in the month of June 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 \$11.9 million at June 30, 2011 were lower by \$7.0 million compared to December 31, 2010, mainly due to lower gas purchase costs in June 2011 as a result of lower gas volumes and lower commodity prices. At June 30, 2011, there was a \$1.6 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 \$2.5 million resulting in a net recoverable amount of \$2.0 million at June 30, 2011, compared to the net recoverable balance 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 \$3.4 million at June 30, 2011, down \$2.7 million from \$6.1 million at December 31, 2010; the gas purchase variance account increased by \$0.6 million as the Company refunded amounts to customers via rate rider credits; and gas commodity costs

paid by the Company in 2010 were less than the gas commodity cost rates paid by customers resulting in a decrease in the gas purchase variance account by \$0.3 million.

### ***Capital Resources***

Planned capital spending 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 \$2.6 million has been spent to date. Contractual commitments of approximately \$1 million have been made for major planned capital expenditures for 2011. These capital expenditures will be funded from cash flow from operations and, if required, draws on the Company's debt facilities.

The Company has also undertaken to spend up to \$2.5 million in the Narrows Inlet Project by mid-year 2012. See "Business Overview – Renewable Energy Business".

### ***Dividends***

The Board of Directors declared a quarterly dividend of 30 cents per share on the Company's common shares, payable September 20, 2011 to shareholders of record at the close of business on September 7, 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](http://www.sedar.com). There were no changes to the Company's significant business risks during the three months ended June 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 June 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 six months period ended June 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 Requirement 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 six months ended June 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 June 30, 2011 comprise 16 and 4 percent of the Company's operating revenues for the three month and six month period ended June 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 REQUIREMENT 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 requirement 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 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 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**

### **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.

### **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.

### **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 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 has 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 sought this exemptive relief from their security regulators and intend to file their financial statements under US GAAP.

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, subject to obtaining all the necessary approvals. The Company has filed its application to the British Columbia and Ontario Securities

Commissions to obtain an exemption order and has commenced the preparation of an application to the BCUC to approve adoption of US GAAP in its regulatory filings.

### **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 is currently underway and expected to be completed by 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.

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 2011 interim 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 utilizes natural gas commodity hedging contracts in order to manage the volatility inherent in the prices of its natural gas purchases. It may also utilize interest rate hedging contracts to reduce the volatility of the interest expense associated with its floating rate debt instruments. As of June 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. The Commission has yet to issue a decision with regard to either the annual gas contracting plan or the gas price risk management plan. The

Company is deferring its gas contracting and hedging activities pending the Commission's review. Each hedging transaction is approved by the Company's price risk management plan committee.

At June 30, 2011, the Company had outstanding natural gas swap and collar contracts relating to natural gas supply as follows:

<b>Financial instrument</b>	<b>Notional quantity</b> (gigajoules)	<b>Percent of annual gas purchases</b> (%)	<b>Delivery period</b>	<b>Price range</b> (per gigajoule)	<b>Estimated net fair value payable</b> (\$000's)
Natural gas swap contracts	2 768 000	31.2	Jul 2011 – Oct 2012	\$3.94 - \$6.49	(2,764)
Collar contracts	53 500	0.6	Apr 2012 – Oct 2012	\$3.80 (floor) - \$5.31 (cap)	(17)
	<b>2 821 500</b>	<b>31.8</b>			<b>(2,781)</b>

The fair value reflects the estimated amounts that the Company would receive or pay at June 30, 2011 to terminate the fixed-price, 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:

<b>Financial instrument</b>	<b>Notional quantity</b> (gigajoules)	<b>Percent of annual gas purchases</b> (%)	<b>Delivery period</b>	<b>Price range</b> (per gigajoule)	<b>Estimated net fair value payable</b> (\$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)
	<b>4 800 100</b>	<b>50.2</b>			<b>(6,139)</b>

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 April 1, 2011, and ended on June 30, 2011 that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

### ***Outstanding Share Data***

At July 29, 2011, there were 200,000 preferred shares and 3,784,804 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 July 29, 2011, there were 176,200 stock options granted and outstanding (representing 5 percent of issued and outstanding common shares). Each option is exercisable for one common share.

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

[\$ in thousands, except per share data]	For the six months ended June 30		For the three months ended June 30	
	2011	2010	2011	2010
<b>Revenues:</b>				
Gas sales and transportation services	41,143	42,020	11,043	12,969
Off system gas sales	6,432	11,157	—	94
Electricity sales	1,154	581	713	581
Other	1,021	1,643	515	1,522
	<b>49,750</b>	<b>55,401</b>	<b>12,271</b>	<b>15,166</b>
<b>Cost of gas:</b>				
Gas sales	15,896	15,811	3,256	4,536
Off system sales	6,432	11,157	—	94
	<b>22,328</b>	<b>26,968</b>	<b>3,256</b>	<b>4,630</b>
	<b>27,422</b>	<b>28,433</b>	<b>9,015</b>	<b>10,536</b>
<b>Operating and maintenance</b>	<b>6,556</b>	<b>6,171</b>	<b>3,286</b>	<b>3,140</b>
<b>Administrative and general</b>	<b>5,301</b>	<b>4,757</b>	<b>2,693</b>	<b>2,458</b>
<b>Depreciation and amortization [note 4]</b>	<b>2,850</b>	<b>4,281</b>	<b>1,395</b>	<b>2,181</b>
<b>Municipal and other taxes</b>	<b>2,471</b>	<b>2,367</b>	<b>1,234</b>	<b>1,194</b>
	<b>17,178</b>	<b>17,576</b>	<b>8,608</b>	<b>8,973</b>
	<b>10,244</b>	<b>10,857</b>	<b>407</b>	<b>1,563</b>
<b>Finance fees</b>	<b>3,497</b>	<b>3,037</b>	<b>1,654</b>	<b>1,588</b>
<b>Income (loss) from continuing operations before income tax expense</b>	<b>6,747</b>	<b>7,820</b>	<b>(1,247)</b>	<b>(25)</b>
<b>Income tax expense (recovery) [note 6]</b>	<b>1,515</b>	<b>2,128</b>	<b>(509)</b>	<b>(30)</b>
<b>Net income (loss) from continuing operations</b>	<b>5,232</b>	<b>5,692</b>	<b>(738)</b>	<b>5</b>
<b>Net income (loss) from discontinued operations [note 5]</b>	<b>20,871</b>	<b>(352)</b>	<b>48</b>	<b>(153)</b>
<b>Net income (loss) and comprehensive income (loss)</b>	<b>26,103</b>	<b>5,340</b>	<b>(690)</b>	<b>(148)</b>
<b>Net (income) loss and comprehensive (income) loss attributable to non-controlling interest</b>	<b>(10)</b>	<b>2</b>	<b>(8)</b>	<b>2</b>
<b>Net income (loss) and comprehensive income (loss) attributable to shareholders</b>	<b>26,093</b>	<b>5,342</b>	<b>(698)</b>	<b>(146)</b>
<b>Basic earnings (loss) per common share: [note 7]</b>				
From continuing operations	1.36	1.54	(0.22)	(0.02)
From discontinued operations	5.64	(0.10)	0.01	(0.04)
	<b>7.00</b>	<b>1.44</b>	<b>(0.21)</b>	<b>(0.06)</b>
<b>Diluted earnings (loss) per common share: [note 7]</b>				
From continuing operations	1.33	1.51	(0.22)	(0.02)
From discontinued operations	5.51	(0.10)	0.01	(0.04)
	<b>6.84</b>	<b>1.41</b>	<b>(0.21)</b>	<b>(0.06)</b>

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]	June 30 2011	December 31 2010
<b>ASSETS</b>		
<b>Current assets:</b>		
Cash and cash equivalents <i>[note 15]</i>	11,651	1,301
Accounts receivable <i>[note 11]</i>	9,260	23,016
Gas purchase variance recoverable	2,074	4,498
Income taxes recoverable	—	1,305
Inventories of natural gas and supplies	905	764
Prepaid expenses	684	1,056
Future income taxes	445	1,105
Current assets of discontinued operations <i>[note 5]</i>	—	594
	<b>25,019</b>	<b>33,639</b>
<b>Plant, property and equipment</b>	<b>197,822</b>	<b>196,176</b>
<b>Intangible assets</b>	<b>1,761</b>	<b>1,766</b>
<b>Regulatory and other assets</b>	<b>14,842</b>	<b>17,659</b>
<b>Long-term assets of discontinued operations <i>[note 5]</i></b>	<b>—</b>	<b>684</b>
	<b>239,444</b>	<b>249,924</b>
<b>LIABILITIES</b>		
<b>Current liabilities:</b>		
Bank indebtedness	—	4,836
Accounts payable and accrued liabilities	11,948	18,909
Income taxes payable	1,622	—
Other taxes payable	4,429	3,388
Derivative financial instruments <i>[note 10]</i>	2,541	5,696
Long-term debt, current	8,206	8,192
Current liabilities of discontinued operations <i>[note 5]</i>	—	197
	<b>28,746</b>	<b>41,218</b>
<b>Long-term debt, non-current</b>	<b>81,993</b>	<b>82,761</b>
<b>Regulatory and other liabilities</b>	<b>10,104</b>	<b>10,892</b>
<b>Future income taxes</b>	<b>20,413</b>	<b>20,736</b>
	<b>141,256</b>	<b>155,607</b>
<b>EQUITY</b>		
<b>Preferred shares</b>	<b>5,000</b>	<b>5,000</b>
<b>Common shares <i>[note 8]</i></b>	<b>9,462</b>	<b>9,038</b>
<b>Contributed surplus</b>	<b>6,841</b>	<b>4,515</b>
<b>Retained earnings</b>	<b>76,602</b>	<b>75,490</b>
<b>Total shareholders' equity</b>	<b>97,905</b>	<b>94,043</b>
<b>Non-controlling interest</b>	<b>283</b>	<b>274</b>
	<b>98,188</b>	<b>94,317</b>
	<b>239,444</b>	<b>249,924</b>

Commitments *[note 13]*

*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 six months ended June 30		For the three months ended June 30	
	2011	2010	2011	2010
<b>Preferred shares</b>				
Balance, beginning and end of period	<b>5,000</b>	5,000	<b>5,000</b>	5,000
<b>Common shares</b>				
Balance, beginning of period	<b>9,038</b>	8,890	<b>9,343</b>	8,971
Employee stock options exercised	<b>424</b>	115	<b>119</b>	34
Balance, end of period	<b>9,462</b>	9,005	<b>9,462</b>	9,005
<b>Contributed surplus</b>				
Balance, beginning of period	<b>4,515</b>	3,699	<b>6,082</b>	4,096
Stock option expense	<b>68</b>	63	<b>14</b>	17
Employee stock options exercised	<b>2,258</b>	524	<b>745</b>	173
Balance, end of period	<b>6,841</b>	4,286	<b>6,841</b>	4,286
<b>Retained earnings</b>				
Balance, beginning of period	<b>75,490</b>	72,847	<b>89,949</b>	77,330
Net income (loss)	<b>26,093</b>	5,342	<b>(698)</b>	(146)
Dividends – preferred shares	<b>(169)</b>	(169)	<b>(169)</b>	(169)
Dividends – common shares	<b>(24,812)</b>	(2,012)	<b>(12,480)</b>	(1,007)
Balance, end of period	<b>76,602</b>	76,008	<b>76,602</b>	76,008
<b>Total shareholders' equity, end of period</b>	<b>97,905</b>	94,299	<b>97,905</b>	94,299
<b>Non-controlling interest</b>				
Balance, beginning of period	<b>274</b>	—	<b>276</b>	—
Contribution from non-controlling interest	<b>12</b>	232	<b>12</b>	232
Distribution to non-controlling interest	<b>(13)</b>	—	<b>(13)</b>	—
Net income (loss) attributable to non-controlling interest	<b>10</b>	(2)	<b>8</b>	(2)
Balance, end of period	<b>283</b>	230	<b>283</b>	230
<b>Total equity, end of period</b>	<b>98,188</b>	94,529	<b>98,188</b>	94,529

*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 six months ended June 30		For the three months ended June 30	
	2011	2010	2011	2010
<b>OPERATING ACTIVITIES</b>				
Net income (loss) attributable to shareholders	26,093	5,342	(698)	(146)
(Income) loss from discontinued operations	(20,871)	352	(48)	153
	5,222	5,694	(746)	7
Add (deduct) items not involving cash:				
Future income taxes [note 6]	343	2,348	532	1,535
Depreciation and amortization [note 15]	2,888	4,362	1,425	2,383
Amortization of termination payment deferral	(841)	—	(418)	—
Share-based compensation	338	320	266	124
Imputed interest on regulatory assets and liabilities	144	160	61	(3)
Other	10	—	(66)	—
	8,104	12,884	1,054	4,046
Changes in operating assets and liabilities [note 15]	6,338	(4,327)	6,941	3,202
Net cash provided by operating activities of continuing operations	14,442	8,557	7,995	7,248
Net cash (used in) provided by operating activities of discontinued operations	(2,856)	14	—	112
<b>Net cash provided by operating activities</b>	<b>11,586</b>	<b>8,571</b>	<b>7,995</b>	<b>7,360</b>
<b>INVESTING ACTIVITIES</b>				
Additions to plant, property and equipment	(2,596)	(2,561)	(1,922)	(1,646)
Increase in restricted cash	(313)	—	(307)	—
Acquisition, net of cash acquired	—	(7,329)	—	(7,329)
Other	(105)	—	(5)	—
Net cash used in investing activities of continuing operations	(3,014)	(9,890)	(2,234)	(8,975)
Net cash provided by (used in) investing activities of discontinued operations	29,706	(546)	—	(298)
<b>Net cash provided by (used in) investing activities</b>	<b>26,692</b>	<b>(10,436)</b>	<b>(2,234)</b>	<b>(9,273)</b>
<b>FINANCING ACTIVITIES</b>				
Decrease in bank indebtedness	(4,836)	(2,579)	—	(2,461)
Issue of long term debt, net of financing costs	—	5,885	—	6,000
Repayment of long-term debt	(792)	(60)	(397)	(60)
Employee stock options exercised	2,682	639	864	207
Dividends paid	(24,981)	(2,181)	(12,649)	(1,176)
Net distribution to non-controlling interest	(1)	232	(1)	232
<b>Net cash (used in) provided by financing activities of continuing operations</b>	<b>(27,928)</b>	<b>1,936</b>	<b>(12,183)</b>	<b>2,742</b>
<b>Increase (decrease) in cash from continuing operations</b>	<b>(16,500)</b>	<b>603</b>	<b>(6,422)</b>	<b>1,015</b>
<b>Increase (decrease) in cash from discontinued operations</b>	<b>26,850</b>	<b>(532)</b>	<b>—</b>	<b>(186)</b>
<b>Increase (decrease) in cash and cash equivalents</b>	<b>10,350</b>	<b>71</b>	<b>(6,422)</b>	<b>829</b>
<b>Cash and cash equivalents, beginning of period</b>	<b>1,301</b>	<b>1,480</b>	<b>18,073</b>	<b>722</b>
<b>Cash and cash equivalents, end of period</b>	<b>11,651</b>	<b>1,551</b>	<b>11,651</b>	<b>1,551</b>
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.**  
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## **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.

In April 2010, the Company and Skookum Power Holdings Corp. acquired a 100% interest in the McNair Creek 9.8 megawatt ‘run of river’ hydro-electricity generation facility located on British Columbia’s Sunshine Coast. Through a series of restructuring transactions completed in December 2010, the Company and Skookum Power Holdings Corp., directly and respectively, own 97.1% and 2.9% of McNair Creek Hydro Limited Partnership and its general partner, MC Hydro Holding Corp. (collectively “McNair Creek”). McNair Creek is a non-regulated business and currently operates under a long-term supply agreement with BC Hydro. The investment in McNair Creek represents the launch of the Company’s renewable power business as part of its business diversification strategy. The key elements of this strategy are to diversify the Company’s risk profile, grow its asset base and enhance its earnings and cash flows.

To continue the Company’s diversification into the renewable power business, the Company and Skookum Power Holdings Corp. formed the Narrows Inlet Limited Partnership. In April 2011, the limited partnership entered into an arrangement to co-develop a 45 megawatt ‘run of river’ hydro-electricity generation facility also located on British Columbia’s Sunshine Coast. The Company and Skookum Power Holdings Corp., directly and respectively, own 98% and 2% of Narrows Inlet Limited Partnership and its general partner, Narrows Inlet GP Inc. (collectively “Narrows Inlet”).

On March 2, 2011, the Company completed the sale of its interest in both Pacific Trail Pipelines Limited Partnership and its general partner, Pacific Trails 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 reported as discontinued operations for all periods presented.

## **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.

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**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.), its 97.1% owned subsidiary, McNair Creek, its 98% owned subsidiary Narrows Inlet, 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.

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 REQUIREMENT 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 requirement 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 plant and equipment and the inclusion of the full actuarially-determined expense for non-pension post-employment benefit plans. As noted, 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 approved rates.

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**4. ACCOUNTING CHANGES (continued)**

**CANADIAN ACCOUNTING STANDARD CHANGES**

**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.

**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.

**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 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”) has determined that publicly accountable enterprises are 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 has 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 sought this exemptive relief from their security regulators and intend to file their financial statements under US GAAP.

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, subject to obtaining all the necessary approvals. The Company has filed its application to the British Columbia and Ontario Securities Commissions to obtain an exemption order and has commenced the preparation of an application to the BCUC to approve adoption of US GAAP in its regulatory filings.

**5. DISCONTINUED OPERATIONS**

On March 2, 2011, PNG completed the sale of its 50% joint venture interests in both Pacific Trails Pipeline Limited Partnership and Pacific Trails Pipeline Management Inc. (collectively “PTP”). These entities were established to develop a proposed 463 kilometre natural gas pipeline in central British Columbia, from Kitimat to Summit Lake (“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.

The 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 recorded initial sales proceeds of \$30.4 million on this transaction, and a resulting pre-tax gain of \$23.4 million in the consolidated statement of income during the first quarter of 2011, net of \$5.2 million in transaction costs incurred in connection with the sale, including incentive compensation of \$4.0 million and professional advisory fees and other related costs of \$1.2 million. The Company recorded a related income tax provision of \$2.6 million, for a net after-tax gain of \$20.9 million on the transaction.

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**5. DISCONTINUED OPERATIONS (continued)**

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, results of operations and carrying value of discontinued operations are as follows:

**Gain on disposal**

[\$ in thousands]	<b>June 30 2011</b>
Proceeds from sale	<b>30,388</b>
Net book value	<b>(1,027)</b>
Transaction costs	<b>(5,192)</b>
<b>Gain on disposal</b>	<b>24,169</b>

**Results of operations**

[\$ in thousands]	<b>Six months ended June 30</b>		<b>Three months ended June 30</b>	
	<b>2011</b>	2010	<b>2011</b>	2010
Gain on disposal	<b>24,169</b>	—	<b>3</b>	—
Project development expenditures	<b>(738)</b>	(529)	—	(253)
Income (loss) before income taxes	<b>23,431</b>	(529)	<b>3</b>	(253)
Income tax (expense) recovery	<b>(2,560)</b>	177	<b>45</b>	100
<b>Net income (loss) and comprehensive income (loss) from discontinued operations</b>	<b>20,871</b>	(352)	<b>48</b>	(153)

**Carrying value**

[\$ in thousands]	<b>June 30 2011</b>	December 31 2010
Assets of discontinued operations		
Cash and cash equivalents	—	593
Accounts receivable	—	1
Current assets of discontinued operations	—	594
Property, plant and equipment	—	684
	—	1,278
Current liabilities of discontinued operations		
Accounts payable and accrued liabilities	—	197

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**6. INCOME TAX EXPENSE**

[\$ in thousands]	For the six months ended June 30		For the three months ended June 30	
	2011	2010	2011	2010
Current income tax expense (recovery)	1,172	(220)	(1,041)	(1,565)
Future income tax expense	343	2,348	532	1,535
	<b>1,515</b>	2,128	<b>(509)</b>	(30)

**7. EARNINGS (LOSS) PER COMMON SHARE**

[\$ in thousands, except share and per share amounts]	Six months ended June 30		Three months ended June 30	
	2011	2010	2011	2010
Net income (loss) from continuing operations	5,232	5,692	(738)	5
Net income (loss) from discontinued operations	20,871	(352)	48	(153)
Net income (loss)	26,103	5,340	(690)	(148)
Net (income) loss attributable to non-controlling interest	(10)	2	(8)	2
Dividends on preferred shares	(169)	(169)	(85)	(85)
Net income (loss) attributable to common shares	25,924	5,173	(783)	(231)
Basic weighted-average number of shares outstanding	3,702,239	3,586,828	3,759,379	3,596,319
Effect of dilutive securities:				
Stock options	86,954	83,496	—	—
Diluted weighted-average number of shares outstanding	3,789,193	3,670,324	3,759,379	3,596,319
<b>Basic earnings (loss) per common share:</b>				
From continuing operations	1.36	1.54	(0.22)	(0.02)
From discontinued operations	5.64	(0.10)	0.01	(0.04)
	7.00	1.44	(0.21)	(0.06)
<b>Diluted earnings (loss) per common share:</b>				
From continuing operations	1.33	1.51	(0.22)	(0.02)
From discontinued operations	5.51	(0.10)	0.01	(0.04)
	6.84	1.41	(0.21)	(0.06)

For the six month periods ended June 30, 2011 and June 30, 2010, no stock options have been excluded from the computation of diluted weighted-average number of shares outstanding because the exercise prices of these options were lower than the average market price of the Company's common shares during these periods.

For the three months ended June 30, 2011, 60,307 stock options (three months ended June 30, 2010 – 95,437) 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 options would have an anti-dilutive effect on earnings per share.

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**8. COMMON SHARES**

[\$ in thousands, except number of shares]	<b>Number of shares</b>	<b>Share capital</b>
Balance, December 31, 2009	3,555,964	8,890
Issue of shares under share option plan	59,180	148
Balance, December 31, 2010	3,615,144	9,038
Issue of shares under share option plan	169,660	424
Balance, June 30, 2011	<b>3,784,804</b>	<b>9,462</b>

During the three and six months ended June 30, 2011, the Company issued 47,800 and 121,860 common shares, respectively, on the exercise of stock options (2010 – 32,600 and 46,200).

**9. SHARE-BASED COMPENSATION**

The following table summarizes information about share options outstanding and exercisable as at June, 30 2011:

<b>Exercise price [\$]</b>	<b>Number of options outstanding</b>	<b>Weighted- average exercise price [\$]</b>	<b>Weighted- average remaining life [years]</b>	<b>Number of options exercisable</b>
12.24 – 14.99	37,600	12.35	7.3	12,480
15.00 – 19.99	53,100	18.66	5.6	45,760
20.00 – 24.99	51,000	22.14	7.0	28,020
25.00 – 26.27	34,500	26.27	9.7	6,900
	<b>176,200</b>	<b>19.82</b>	<b>7.2</b>	<b>93,160</b>

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**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]	June 30, 2011		December 31, 2010	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
<b>Held for trading</b>				
Cash and cash equivalents <sup>(1)</sup>	11,651	11,651	1,894	1,894
<b>Loans and receivables</b>				
Accounts receivable <sup>(1)</sup>	9,260	9,260	23,017	23,017
<b>Other financial liabilities</b>				
Bank indebtedness	—	—	4,836	4,836
Accounts payable and accrued liabilities <sup>(1)</sup>	11,948	11,948	19,106	19,106
Long-term debt, including current portion	90,199	101,701	90,953	100,735

<sup>(1)</sup> December 31, 2010 comparative figures include amounts classified with current assets and current liabilities of discontinued operations (note 5).

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 hedges exposures to fluctuations in natural gas prices through the use of derivative financial instruments. The Company has two hedge lines of credit, each is 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.

The facility with the Company's operating line provider has one financial covenant which requires the Company's debt leverage not to exceed 65 percent. The second facility, arranged in January 2010, has two financial covenants, one which requires the Company's debt leverage not to exceed 65 percent, and the second which requires the Company to maintain a minimum interest coverage of 1.5 times using earnings before interest, income taxes and expenditures on the KSL Project to a maximum of \$10.0 million. Further, if the Company's secured debt rating is less than BBB (low) or the Company has no debt rating, the interest coverage requirement is 2.0 times or higher.

The risk management facilities allow the Company to hedge natural gas purchases in accordance with its annual gas contracting and gas supply price risk management plan and to enter into interest rate hedging transactions.

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**10. FINANCIAL INSTRUMENTS (continued)**

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 June 30, 2011**

<b>Financial instrument</b>	<b>Notional quantity</b> (gigajoules)	<b>Percent of annual gas purchases</b> (%)	<b>Delivery period</b>	<b>Price range</b> (per gigajoule)	<b>Estimated net fair value payable</b> (\$000's)
Natural gas swap contracts	2 768 000	31.2	Jul 2011 – Oct 2012	\$3.94 - \$6.49	(2,764)
Collar contracts	53 500	0.6	Apr 2012 – Oct 2012	\$3.80 (floor) - \$5.31 (cap)	(17)
	<b>2 821 500</b>	<b>31.8</b>			<b>(2,781)</b>

Of the \$2.8 million liability at June 30, 2011, \$2.5 million is recorded as a current liability and \$0.3 million is recorded in non-current regulatory and other liabilities on the interim consolidated balance sheet.

**As at December 31, 2010**

<b>Financial instrument</b>	<b>Notional quantity</b> (gigajoules)	<b>Percent of annual gas purchases</b> (%)	<b>Delivery period</b>	<b>Price range</b> (per gigajoule)	<b>Estimated net fair value receivable (payable)</b> (\$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)
	<b>4 800 100</b>	<b>50.2</b>			<b>(6,139)</b>

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.

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**11. RISK MANAGEMENT**

**Credit risk**

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

[\$ in thousands]	<b>June 30 2011</b>	December 31 2010
Core market – residential and commercial	<b>9,207</b>	19,581
Industrial customers	<b>452</b>	779
Off-system sales customers	<b>—</b>	3,167
Other	<b>465</b>	338
	<b>10,124</b>	23,865
Less: Allowance for doubtful accounts	<b>(864)</b>	(849)
	<b>9,260</b>	23,016

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

[\$ in thousands]	<b>June 30 2011</b>	December 31 2010
Unbilled revenues	<b>3,844</b>	11,991
Past due 0 to 30 days (current)	<b>5,261</b>	11,119
Past due 31 to 90 days	<b>446</b>	303
Past due over 91 days	<b>573</b>	452
	<b>10,124</b>	23,865
Less: Allowance for doubtful accounts	<b>(864)</b>	(849)
	<b>9,260</b>	23,016

Changes in the allowance for doubtful accounts are as follows:

[\$ in thousands]	<b>June 30 2011</b>	December 31 2010
Balance, beginning of period	<b>849</b>	2,044
Provision for doubtful accounts	<b>—</b>	265
Write-off of bad debts, net of recoveries, and other	<b>15</b>	(1,460)
Balance, end of period	<b>864</b>	849

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## **11. RISK MANAGEMENT (continued)**

### **Liquidity risk**

The Company's overall liquidity risk has improved slightly from December 31, 2010, with the net proceeds of the sale of PTP less special dividends paid (see note 5).

As at June 30, 2011 the Company had utilized \$2.6 million of its \$25.0 million operating line facility to issue letters of credit and had utilized \$16.0 million of the \$35.0 million available under its revolving term facility. The Company also has cash and cash equivalents of \$11.7 million.

## **12. CAPITAL MANAGEMENT**

The Company's objective in managing capital remains largely unchanged from December 31, 2010. The capital structure consisted of the following components at June 30, 2011: bank indebtedness, long-term debt and shareholders' equity, totaling \$188.1 million [December 31, 2010 – \$189.9 million].

The Company's objectives with its capital structure are:

- to maintain the amount of common equity in its capital structure at the level approved by the Commission for the purpose of determining rates for the Company's regulated operations plus sufficient equity to support investments in the Company's non-regulated businesses; and
- to maintain a credit rating at which the Company has sufficient access to capital and to natural gas and other supplies on reasonable terms to be able to provide safe, secure and reliable service to its customers, which in turn is critical to the Company's ongoing prosperity.

The Company made significant progress in 2010 toward achieving the first objective while simultaneously maintaining its credit rating. Provided that the Company is able to maintain its credit rating, further progress on the first objective is possible through additional investments in renewable power projects.

During the fiscal year ending December 31, 2010 the Company added a second hedge facility, extended and increased the amount available under its revolving term facility and extended and amended its operating line. The hedge facility, arranged in January 2010, has two financial covenants, one which requires the Company's debt leverage not to exceed 65 percent, and the second which requires the Company to maintain an interest coverage of 1.5 times or higher using earnings before interest, income taxes and expenditures on the KSL Project to a maximum of \$10.0 million. Further, if the Company's secured debt rating is less than BBB (low) or the Company has no debt rating, the interest coverage requirement is 2.0 times or higher.

The amendment to the operating line included an increase to \$25.0 million of the credit available to the Company as well as increases in stand-by fees and interest rate spreads to reflect then current market conditions. No changes were made to the financial covenant under the operating line.

The \$25.0 million operating line and \$35.0 million 5-year revolving term facility are subject to a financial covenant requiring the Company's debt leverage not to exceed 65 percent. The 5-year revolving term facility contains an additional covenant which states that if the Company's secured debt rating is less than BBB (low) or the Company has no debt rating, the Company must maintain an interest coverage of 2.0 times or higher using earnings before interest, income taxes and expenditures on the KSL Project to a cumulative maximum of \$10.0 million. On June 10, 2011 Dominion Bond Rating Services ("DBRS") confirmed the Company's secured debt ratings at BBB (low). The Company is in compliance with its debt covenants as at June 30, 2011.

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

**13. COMMITMENTS**

The Company has long-term natural gas purchase arrangements all of which are transacted at market prices and in the normal course of business. The Company's purchase commitments as at June 30, 2011 under various gas supply contracts expiring through 2015 were as follows:

[\$ in thousands]

2011	4,876
2012	4,787
2013	51
2014	51
2015	42
<b>Total</b>	<b>9,807</b>

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 June 30, 2011.

The Company is required to make annual funding contributions of an estimated \$2.2 million to its pension plan as determined by the actuarial valuation report as at December 31, 2009 which was completed during the third quarter of 2010.

The Company continues to pursue an investment opportunity in the proposed 45 MW Narrows Inlet run-of-river renewable energy project located near Sechelt, British Columbia. The Company has a commitment to invest up to \$2.5 million (of which \$0.9 million has been invested to date) to advance the Narrows Inlet project to the commencement-of-construction stage which is expected to be achieved by mid-to-late 2012. The Narrows Inlet Project consists of five proposed developments situated on four creeks that are located within a radius of 5 to 8 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 B.C. Hydro in the spring of 2010.

**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 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 six months ended June 30, 2010 and 2011:

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

**14. SEGMENTED INFORMATION (continued)**

[\$ in thousands]	Six months ended June 30, 2011			Six months ended June 30, 2010		
	Gas Transmission and Distribution	Renewable Energy	Consolidated	Gas Transmission and Distribution	Renewable Energy	Consolidated
Revenues	48,596	1,154	49,750	54,820	581	55,401
Cost of gas	22,328	—	22,328	26,968	—	26,968
	<b>26,268</b>	<b>1,154</b>	<b>27,422</b>	<b>27,852</b>	<b>581</b>	<b>28,433</b>
Operating and maintenance	6,471	85	6,556	6,171	—	6,171
Administrative and general	4,834	467	5,301	4,160	597	4,757
Depreciation and amortization	2,609	241	2,850	4,207	74	4,281
Municipal and other taxes	2,419	52	2,471	2,346	21	2,367
	<b>16,333</b>	<b>845</b>	<b>17,178</b>	<b>16,884</b>	<b>692</b>	<b>17,576</b>
	<b>9,935</b>	<b>309</b>	<b>10,244</b>	<b>10,968</b>	<b>(111)</b>	<b>10,857</b>
Finance fees	3,147	350	3,497	2,890	147	3,037
Income tax expense (recovery)	1,520	(5)	1,515	2,135	(7)	2,128
Net income (loss) from continuing operations	<b>5,268</b>	<b>36</b>	<b>5,232</b>	<b>5,943</b>	<b>(251)</b>	<b>5,692</b>

  

[\$ in thousands]	Three months ended June 30, 2011			Three months ended June 30, 2010		
	Gas Transmission and Distribution	Renewable Energy	Consolidated	Gas Transmission and Distribution	Renewable Energy	Consolidated
Revenues	11,558	713	12,271	14,585	581	15,166
Cost of gas	3,256	—	3,256	4,630	—	4,630
	<b>8,302</b>	<b>713</b>	<b>9,015</b>	<b>9,955</b>	<b>581</b>	<b>10,536</b>
Operating and maintenance	3,240	46	3,286	3,140	—	3,140
Administrative and general	2,487	206	2,693	2,031	427	2,458
Depreciation and amortization	1,275	120	1,395	2,107	74	2,181
Municipal and other taxes	1,209	25	1,234	1,173	21	1,194
	<b>8,211</b>	<b>397</b>	<b>8,608</b>	<b>8,451</b>	<b>522</b>	<b>8,973</b>
	<b>91</b>	<b>316</b>	<b>407</b>	<b>1,504</b>	<b>59</b>	<b>1,563</b>
Finance fees	1,482	172	1,654	1,441	147	1,588
Income tax expense (recovery)	(559)	50	(509)	(71)	41	(30)
Net income (loss) from continuing operations	<b>(833)</b>	<b>95</b>	<b>(738)</b>	<b>134</b>	<b>(129)</b>	<b>5</b>

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

**14. SEGMENTED INFORMATION (continued)**

Other segment information regarding capital expenditures, assets and liabilities is as follows:

**As at and for the six months ended June 30, 2011**

[\$ in thousands]	<b>Gas Transmission and Distribution</b>	<b>Renewable Energy</b>	<b>Consolidated</b>
Capital expenditures	2,213	383	2,596
Plant, property & equipment	178,137	19,685	197,822
Assets	217,053	22,391	239,444
Liabilities	128,491	12,765	141,256

As at and for the year ended December 31, 2010

[\$ in thousands]	<b>Gas Transmission and Distribution</b>	<b>Renewable Energy</b>	<b>Consolidated</b>
Capital expenditures	6,896	4	6,900
Plant, property & equipment	177,044	19,132	196,176
Assets	227,475	21,171	248,646
Liabilities	143,034	12,376	155,410

**15. SUPPLEMENTAL CASH FLOW INFORMATION**

[\$ in thousands]	<b>June 30 2011</b>	<b>December 31 2010</b>
<b>Cash and cash equivalents:</b>		
Cash	1,651	1,301
Cash equivalents	10,000	—
	<b>11,651</b>	<b>1,301</b>

[\$ in thousands]	<b>Six months ended June 30</b>		<b>Three months ended June 30</b>	
	<b>2011</b>	2010	<b>2011</b>	2010
<b>Depreciation and amortization:</b>				
Depreciation and amortization, per statements of income	2,850	4,281	1,395	2,181
Amortization of debt issue costs included in long term interest expense	38	81	30	202
Total depreciation and amortization	<b>2,888</b>	4,362	<b>1,425</b>	2,383

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

**15. SUPPLEMENTAL CASH FLOW INFORMATION (continued)**

[\$ in thousands]	Six months ended		Three months ended	
	June 30		June 30	
	2011	2010	2011	2010
<b>Changes in operating assets and liabilities:</b>				
(Increase) decrease in:				
Accounts receivable	13,756	17,123	13,761	12,314
Income taxes recoverable	1,305	(1,826)	—	(1,826)
Gas purchase variance recoverable	(957)	—	(957)	—
Prepaid expenses and other	372	869	112	894
Inventories of supplies and natural gas	(141)	292	32	156
Increase (decrease) in:				
Accounts payable and accrued liabilities	(10,376)	(15,090)	(5,186)	(6,512)
Other taxes payable	1,035	431	279	1,149
Income taxes payable	(943)	(1,041)	(1,705)	(1,173)
Gas purchase variance payable	—	(1,288)	92	(530)
Changes in regulatory assets and liabilities	2,618	(3,567)	603	(1,151)
Contributions to defined benefit plans in excess of expense	(331)	(230)	(90)	(119)
Attributable to operating activities	6,338	(4,327)	6,941	3,202
<b>Interest and tax payments:</b>				
Income taxes paid	810	2,496	664	573
Interest paid	3,190	2,726	1,947	1,710

**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.

**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 June 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 April 1, 2011 and ended on June 30, 2011 that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

Date: July 29, 2011

"Roy G. Dyce"

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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 June 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 April 1, 2011 and ended on June 30, 2011 that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

Date: July 29, 2011

"Janet Kennedy"

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