



PACIFIC NORTHERN GAS LTD.

**ANNUAL
INFORMATION FORM**

For the 12 month period ended December 31, 2010

March 3, 2011

TABLE OF CONTENTS

GLOSSARY	4
SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS	5
THE COMPANY	7
Corporate Structure	7
Business Strategy	7
General Development of the Business	9
Trends and Competition	14
BUSINESS OF THE COMPANY	15
Overview	15
Western System	16
Northeast System	17
Properties	18
Gas Sales and Transportation	18
Large Industrial Customers	20
Natural Gas Supply	21
Customer Additions	22
Government Regulation	23
Rate Base and Common Equity	25
Credit Facilities	25
Short-term Debt	26
Long-term Debt	26
Environment, Health and Safety Matters	27
Employees	28
RISK FACTORS	29
Usage Risk and Impact of Changes in Economic Conditions	29
Acquisition and Integration Strategies	29
Liquidity, Cash Flow and Capital Availability Risks	30
Commodity Price and Supply Risks	31
Potential for Termination of Large Industrial Contracts	32
Regulatory Risks	32
Facility and Insurance Risks	33
Environmental and Safety Risks	33
Renewable Energy Business Risks	34
Derivatives Risk	34
Human Resources Risks	34
Employee Future Benefits Plan Risk	35
First Nations Matters	35
Share Price Volatility	35
Transition to IFRS	35
DIVIDENDS	36

DESCRIPTION OF CAPITAL STRUCTURE	36
Common Shares	36
Cumulative Redeemable Junior Preferred Shares.....	36
6 ¾ Percent Cumulative Redeemable Preferred Shares.....	36
Ratings	37
MARKET FOR SECURITIES	38
LEGAL PROCEEDINGS.....	39
DIRECTORS AND OFFICERS	39
Directors.....	40
Officers	41
Audit Committee.....	42
INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS.....	44
MATERIAL CONTRACTS	45
TRANSFER AGENT.....	45
EXPERTS	45
ADDITIONAL INFORMATION.....	45
SCHEDULE “A”	46

GLOSSARY

In this annual information form, *gigajoule* (GJ) is equivalent to 947,817 British thermal units, *terajoule* (TJ) means one thousand GJ and *petajoule* (PJ) means one million GJ. One GJ is equivalent to approximately 0.9225 Mcf of gas. *Mcf* means one thousand cubic feet and *MMcf* means one million cubic feet. 10^3m^3 means one thousand cubic metres. In volumetric units, one thousand cubic metres is equivalent to 35.30 thousand cubic feet.

Non-GAAP Measures

References to “operating margin” are to revenues less cost of gas. Operating margin is not a recognized measure under Canadian generally accepted accounting principles (“GAAP”) and does not have a standardized meaning prescribed by GAAP. Therefore, operating margin may not be comparable to similar measures presented by other issuers. Readers are cautioned that operating margin should not replace revenues as a measure of performance. Management believes operating margin is a meaningful measure of performance because the financial results of Pacific Northern Gas Ltd. (“the Company”) are best measured by excluding the cost of gas which is flowed through to customer rates without a mark-up.

References to “net earnings before acquisition and reorganization costs” represents a pro forma earnings measure based on net earnings before deduction of acquisition and reorganization costs incurred. This pro forma measure is not a recognized measure under GAAP and does not have a standardized meanings prescribed by GAAP. Therefore, net earnings before acquisition and reorganization costs may not be comparable to similar measures presented by other issuers. Readers are cautioned that net earnings before acquisition and reorganization costs should not replace net earnings as a measure of performance. Management believes net earnings before acquisition and reorganization costs is a meaningful measure of performance for the Company’s recently acquired hydroelectric facility as it removes the impact of one-time acquisition and reorganization costs and provides earnings results that might be considered more indicative of future performance.

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

This annual information form 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 the 2011 revenue requirements applications;
- The timing of the closing of the sale of the Company's interest in Pacific Trail Pipelines Limited Partnership ("PTP") and receipt of payments (see "Business Overview – KSL Project – Sale of PTP");
- The timing for the commencement of transportation service to a potential small scale liquefied natural gas ("LNG") facility and the cost of reactivating compressor stations to provide such service (see "The Company – General Development of the Business – Regulated Business Initiatives – Capacity Utilization on the Western System" and "Business of the Company – Western System – Transmission Pipeline System");
- Growth and opportunities in renewable energy generation;
- The benefits of the acquisition of the McNair Creek hydroelectric generation facility (see "The Company – General Development of the Business – Renewable Energy Business");
- The regulatory treatment of the West Fraser termination payment (see "The Company – General Development of the Business – Closure of West Fraser Kitimat B.C. Paper Mill");
- The competitiveness of retail gas rates relative to electricity rates (see "The Company – Trends and Competition – Competitiveness of Rates");
- The trends in customer numbers in the Western and Northeast service areas;
- The impact of economic conditions on the Company's performance and prospects for growth;
- 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 annual information form, 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 annual information form under "Risk Factors" which could cause the Company's actual results and experience to differ materially from the anticipated results or other expectations expressed. Such risks and uncertainties include but are not limited to: general economic conditions and markets; gas supply and availability; gas commodity price volatility; competition; decisions by regulators; seasonal weather patterns; federal and provincial climate change initiatives; financing of investments as well as the value of such investments; the cost and availability of capital; the impact on the Company's liquidity if it were to go offside of the covenants in its debt facilities; successful execution of strategic initiatives; the ability of the Company to attract and retain quality employees, and the impact of accounting changes, including the transition to International Financial Reporting Standards ("IFRS"). Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this annual information form 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.

THE COMPANY

Corporate Structure

Pacific Northern Gas Ltd. was incorporated under the laws of British Columbia as a private company on October 28, 1965 and was converted to a public company on November 4, 1968. The head and registered offices of the Company are located at Suite 950, 1185 West Georgia Street, Vancouver, British Columbia, V6E 4E6 and its principal operating office is at 2900 Kerr Street, Terrace, British Columbia.

Pacific Northern Gas (N.E.) Ltd. (“Pacific Northern (N.E.)”) was formed under the laws of British Columbia on June 30, 1999 by the amalgamation of Pacific Northern Gas (N.E.) Ltd., Centra Gas Fort St. John Inc. and Peace River Transmission Company Limited. Pacific Northern (N.E.) is a wholly owned subsidiary of the Company with its main operating offices at 1208 – 102nd Avenue, Dawson Creek and 10016 – 104 Street, Fort St. John, British Columbia.

On July 17, 2006, the Company formed Pacific Trail Pipelines Limited Partnership (“PTP”) as a 50/50 partnership between the Company and Galveston LNG Inc. for the purpose of developing the KSL Project, as discussed below.

The Company owns and operates a natural gas transmission and distribution utility operating within the west-central portion of northern British Columbia (“Western system”). Pacific Northern (N.E.) owns and operates a distribution utility in the northeast part of 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 utilities are separate stand-alone systems and both are regulated by the Commission. The Company also operates and owns a 97 percent interest in the 9.8 megawatt McNair Creek hydro-electricity generation facility (“McNair”) located on B.C.’s Sunshine Coast

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 and evaluating development and acquisition opportunities, particularly in the renewable energy sector. It is also reviewing its business strategy in light of the recent sale of its interest in the KSL Project and the March 2, 2011 receipt of \$30 million of the \$50 million sales price (see “General Development of the Business – KSL Project – Sale of PTP”)

In respect of its strategy, the Company has determined that:

- It must grow profitably and increase its market capitalization in order to enhance shareholder value;
- It is important for the Company to seek growth opportunities in areas that complement its strengths and fit well within its existing risk profile;

- Merger and acquisition opportunities are limited in the Canadian utility sector given the Company's small relative size; and
- There are two near-term business improvement opportunities in the Company's service area that would materially benefit the Company and its customers: (i) the LNG Partners small scale liquefied natural gas LNG project; and (ii) the transportation service agreements for delivery of LNG to supplement the KSL Project and an operating and maintenance agreement for the KSL Project (see "General Development of the Business – KSL Project – Sale of PTP" and "General Development of the Business – Regulated Business Initiatives – Capacity Utilization on the Western System").

As there are limited opportunities to expand through acquisitions of Canadian natural gas distribution assets, management and the Board of Directors have identified specific parameters for evaluating growth opportunities through electricity and renewable energy generation. In particular, based on the following factors, it has been determined that renewable independent hydro power development and operation with long-term off-take contracts would provide the best fit for the Company:

- renewable energy is a growth area;
- long term fixed-price off-take agreements are available for independent power projects in a number of Canadian jurisdictions, including British Columbia;
- the technology is well developed and the resource is relatively predictable;
- the Company can utilize its operating skills, permitting expertise, project management capabilities, financing acumen and energy market and regulatory expertise;
- both operating projects and development projects are available in sizes which fit the Company's access to capital; and
- although the Company does not have internal technical expertise for hydro power, it can access that expertise via partnerships or acquisition.

In pursuit of that strategy, the Company entered into a partnership with Skookum Power Corp. ("Skookum Power") and completed the acquisition of the McNair Creek hydro-electricity generation facility in April 2010 (see "General Development of the Business – Renewable Energy Business"). The Company can give no assurances that it will be successful in identifying, financing or realizing value from these opportunities.

The Company has focused on increasing its dividend yield to shareholders to a level more consistent with other publicly traded utilities. In that regard, following dividend increases in 2009, the Company announced a quarterly dividend increase in February, 2010 to \$0.28 per common share and a further increase in October, 2010 to \$0.30 per common share. The Company also implemented a normal course issuer bid ("NCIB") in March 2009, pursuant to which it purchased and subsequently cancelled 122,416 common shares at an average price of \$14.69 per share before the NCIB closed in March, 2010.

General Development of the Business

Renewable Energy Business

In April 2010, the Company entered into a joint development and operating agreement with Skookum Power gaining access to extensive expertise in hydrology, engineering and commercial development to support its new renewable energy business platform. The principals of Skookum Power are former power company executives with collectively more than 50 years experience in the hydro-electricity and energy sectors.

On April 19, 2010, the Company in partnership with Skookum Power closed the acquisition of the 9.8 megawatt McNair Creek hydro-electricity generation facility (“McNair”) from Kiewit Hydropower Investors Inc. and Renewable Power Corp. with the Company holding a 97% share. The McNair facility is located on B.C.’s Sunshine Coast and has been in operation for more than 5 years. The facility’s generation is committed for sale under a long-term contract to BC Hydro.

The total purchase price was approximately \$17.5 million and was funded in part by the assumption of \$9.4 million in non-recourse debt and the remainder in cash payments. The Company’s cash purchase obligations were met through drawings on its existing credit facilities. The transaction is expected to be cash flow positive for 2011 onwards.

For the period from the acquisition date to December 31, 2010, the Company recorded net earnings before acquisition and reorganization costs of approximately \$0.15 million from the McNair facility operations. Transaction costs amounted to approximately \$0.7 million after-tax for the nine month period ended December 31, 2010. Production from the McNair facility is seasonal. The Company expects that almost 40 percent of McNair’s 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.

The acquisition of McNair was not a “significant acquisition” within the meaning under National Instrument 51-102 and no Form 51-102F4 was filed.

KSL Project – Sale of PTP

PTP is the developer of a proposed 463 kilometre natural gas pipeline from Summit Lake, B.C. to Kitimat, B.C. (“KSL Project”). The KSL Project would serve the planned Kitimat LNG facility owned by Apache Canada and EOG Canada. The Kitimat LNG facility and the KSL Project have the support of, and will provide benefits to, many stakeholders including the First Nations with traditional territories in the project area. The Company has been working on the KSL Project since 2005 and has held a 50 percent interest in PTP since its formation in mid-2006.

In the third quarter of 2010, the Company commenced the detailed design phase of the KSL Project and commenced capitalization of these expenditures. The Company’s share of total 2010 expenditures on the KSL Project to December 31 was \$1.25 million, including \$0.7 million which has been capitalized relating to engineering and technical studies.

On February 4, 2011, the Company entered into an agreement to sell its 50 percent interest in PTP to Apache Canada Ltd. (“Apache Canada”) and EOG Resources Canada Inc. (“EOG Canada”), the Company’s partners in the KSL Project, for payment of up to \$50 million. This transaction has two components, the first being a cash payment of \$30 million that the Company received on March 2, 2011, and the second being a cash payment of \$20 million to be paid contingent on the purchasers making a decision to proceed with construction of the Kitimat LNG facility. The Company can give no assurances that construction of the Kitimat LNG facility will be completed or that the \$20 million payment will be made.

As a result of the transaction, Apache Canada’s ownership of the pipeline will increase from 25.5 percent to 51 percent and EOG Canada’s ownership will increase from 24.5 percent to 49 percent.

The Company’s shareholders will benefit from the full crystallization of cash proceeds received on this transaction. The \$50 million sale proceeds have an approximate value of \$9 to \$10 per share after taxes and related expenses, including payments under the KSL Project management incentive plan, should the second contingent payment of \$20 million be released.

The Company has recorded \$7.3 million of KSL Project expenditures from its inception to December 31, 2010, of which \$6.6 million has been expensed and \$0.7 million has been capitalized.

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

Transportation Service Agreements

In connection with the sale, the Company has reached agreement on the terms for a 20-year transportation service agreement with Apache Canada and EOG Canada that will significantly increase the utilization of the Company’s current pipeline in the event that LNG Partners does not claim this capacity first.

If the LNG Partners project does not proceed and the Kitimat LNG facility does proceed, Apache Canada and EOG Canada would use up to 50 MMcf per day of the Company’s existing pipeline capacity to supplement KSL Project throughput. Initial deliveries via the Company’s facilities would be 30 MMcf per day starting with initial LNG production. Delivery of an additional 20 MMcf per day via the Company’s facilities would commence 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.

Operating and Maintenance Agreement

The Company will operate the KSL Project pipeline under an operating and maintenance agreement negotiated with Apache Canada and EOG Canada. The operating and maintenance agreement will have an initial term of seven years beginning in 2015, with renewal provisions, and will be subject to approval by the Commission.

Closure of West Fraser Kitimat B.C. Paper Mill

West Fraser Timber Co. Ltd. (“West Fraser”) permanently closed its Kitimat B.C. linerboard mill at the end of January 2010. The Company had a transportation service agreement with West Fraser which specified a daily contract demand volume of 6.0 MMcf (million cubic feet) per day that was set to expire on December 31, 2013. Under the terms of the transportation agreement, West Fraser paid the Company an annual demand charge of approximately \$2.1 million and was entitled to cancel its obligations by providing the Company with a termination payment that would recover almost 80 percent of the lost revenues under the remaining term of the agreement.

On May 31, 2010 West Fraser provided the Company with the required six months cancellation notice. West Fraser continued to pay the monthly demand charge due under the transportation agreement until November 2010. A termination payment of just over \$5 million was paid on December 1, 2010. The Company expects that the termination payment will be amortized into earnings over the remaining life of the agreement; the same regulatory treatment accorded the Methanex Corporation (“Methanex”) termination payment made in 2006. 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.

Regulated Business Initiatives

The Company is focused on ensuring that the regulatory environment allows it an opportunity to earn a fair and reasonable return on investment and provide the required flexibility to react to market conditions and preserve liquidity. In June 2010 the Commission approved the negotiated settlements achieved in relation to the Company’s capital structure and equity risk premium application and its 2010 revenue requirements applications. The Company’s 2011 revenue requirements applications are currently under review with the expectation negotiated settlements will be reached in the second quarter of 2011. The Company is also continuing to pursue an opportunity to increase capacity utilization on the Western system.

Capacity Utilization on the Western System

A letter agreement with Merrill Lynch Commodities Inc. (“Merrill Lynch”) provided Merrill Lynch with an option to contract for 75 MMcf per day of firm gas transportation service using existing capacity on the Company’s Western system. The letter agreement also provided for the parties to negotiate a definitive transportation service agreement (“TSA”) for filing with the Commission for acceptance as a filed tariff. The TSA was accepted by the Commission as a filed tariff on June 17, 2010. During final negotiations, the parties agreed to increase the capacity option from 75 to 80 MMcf per day. The TSA documents the option provisions and the

transportation service provisions that would apply following exercise of the option. On August 11, 2010 Merrill Lynch assigned and novated the TSA to LNG Partners LLC (“LNG Partners”). If LNG Partners exercises its option, it is expected to utilize the transportation service to deliver natural gas to a small scale LNG facility to be located on the Douglas Channel near Kitimat, B.C. It is expected that the LNG produced at this facility would be exported to LNG markets in Asia.

The Company has received option fees of \$4.5 million to secure an exclusive option under the TSA until June 30, 2011 to contract for firm gas transportation capacity for a two- to five-year primary term, with a right to renew for an additional two- to fifteen-year term. LNG Partners may extend the option period by up to two further six month periods, with payment of \$1 million for each extension.

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 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. If service commences by June 30, 2012 all of the option fees previously paid to the Company will be credited to transportation service fees payable in 2012. The option fee credit to LNG Partners will be reduced by \$0.5 million if service commences after June 30, 2012 but before December 31, 2012. A further reduction of \$0.5 million will apply if service commences after December 31, 2012. If 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.

Negotiated Settlement Agreements for the 2010 Revenue Requirements Applications and the Capital Structure and Equity Risk Premium Application (“CAP/ROE Application”)

On June 23, 2010 the Commission approved the negotiated settlement agreements in respect of the 2010 revenue requirements applications for the Western system and Northeast system and the CAP/ROE Application (“settlement agreements”). The key matters agreed to under the settlement agreements are summarized as follows:

- The parties agreed the common equity capitalization and risk premiums relative to the benchmark utility return on equity (“ROE”) for the Western system division (effective January 1, 2009) and the Fort St. John/Dawson Creek and Tumbler Ridge divisions (effective January 1, 2010) would be as follows:

	Western System Division	Fort St. John/Dawson Creek Division	Tumbler Ridge Division
Common Equity Capitalization	45%	40%	40%
Equity Risk Premiums	65 basis points	40 basis points	65 basis points

On a consolidated basis, this provided the Company with the opportunity to increase overall earnings in 2010 by approximately \$0.6 million or \$0.17 per share. Further, an additional \$0.5 million of net income was included in the second quarter of 2010 to reflect the January 1, 2009 effective date for the Western system common equity capitalization ratio adjustment.

The equity risk premiums are relative to the benchmark utility ROE of 9.50% that became effective July 1, 2009 resulting in the following ROE's in 2009 and 2010 for each division:

Year	Western System Division	Fort St. John/Dawson Creek Division	Tumbler Ridge Division
2009	9.63%	9.38%	9.63%
2010	10.15%	9.90%	10.15%

The 2009 ROE's are lower than applicable in 2010 to account for the fact the benchmark ROE of 9.50% was made effective July 1, 2009.

- The interim rates effective January 1, 2010 were made permanent for 2010. Having regard to the fact the interim rates were based on forecast 2010 costs of service using common equity capitalization and ROE figures that were less than the agreed to figures, the parties agreed the difference between: (i) the 2010 gross margins using the interim rates; and (ii) the costs of service based on the parameters agreed to under the final settlement agreements would be recorded, for future disposition, in the common equity deferral accounts approved by the Commission under Order G-172-09.
- On December 31, 2010, the Company used a portion of the balance in the LNG Partners option fees deferral account to draw down the remaining \$2.0 million balance in the Western system common equity deferral account as agreed under the Western system negotiated settlement agreement.

Trends and Competition

Competitiveness of Rates

As a regulated utility, the Company does not face competition from other natural gas transmission and distribution companies. The Company does, however, compete with other energy sources in meeting the needs of energy consumers in its service areas. The main sources of competition are from electricity and wood in the residential sector, electricity in the commercial sector and wood waste in the industrial forestry sector (see “Risk Factors – Usage Risks and Impact of Changes in Economic Conditions”).

As a distributor of natural gas, the Company continuously monitors the competitiveness of its natural gas retail rates relative to alternative heating sources in its service area. The Company’s current residential rates in all divisions are lower than the current comparable residential electricity rate. Declines in gas commodity prices payable by the Company during 2010 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 rate increases have been higher than the impact of the carbon tax on natural gas prices and electricity rates are expected to rise over time to meet the Province’s energy policy objectives. The Company’s 2011 Western system revenue requirements application is seeking Commission approval of a bundled average residential rate of \$20.31 per GJ effective January 1, 2011, including the current carbon tax of \$0.9932 per GJ. This is approximately 5 percent less than the equivalent residential conservation electricity rate of \$21.44 per GJ.

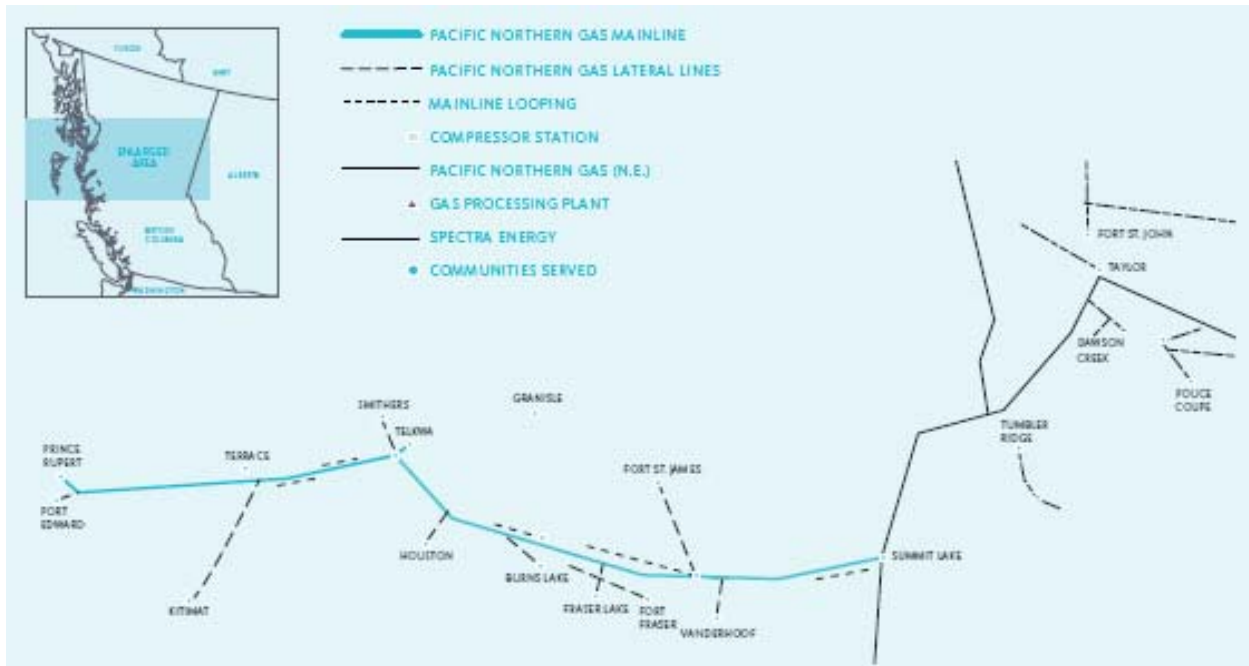
Amendments made to the Utilities Commission Act (British Columbia) in 2008 focus on the energy conservation and demand side management goals and objectives set forth in the Energy Plan.

In the Company’s Northeast system service area there has been continued growth in the oil and gas sector, which has expanded the Company’s customer base in that area.

BUSINESS OF THE COMPANY

Overview

The Company's Western system extends from Summit Lake to Prince Rupert and Kitimat. The Northeast system includes Tumbler Ridge, Dawson Creek, Fort St. John and the surrounding areas. The Company also operates a small propane vapour distribution system in Granisle, British Columbia.



At year end 2010 the Company was delivering gas to 39,405 residential, commercial and industrial customers. The Company had two large industrial customers in 2010: Rio Tinto Alcan Inc. ("Rio Tinto Alcan") and British Columbia Hydro and Power Authority ("BC Hydro"). These two customers accounted for 9.9 percent of total gas deliveries and 5.3 percent of the Company's operating margin during 2010.

The Company's combined rate base for 2010, as approved by the Commission, was approximately \$170 million.

Gas distributed by the Company to its residential and commercial customers and to certain industrial customers in 2010 was purchased under various agreements with gas producers and other suppliers. Most of the Company's industrial customers satisfy their gas requirements by purchasing gas directly from producers or other suppliers and contracting with the Company for the transportation of that gas through the Company's pipeline systems. Since the Company earns income from the transportation and distribution of gas and not from the sale of gas as a commodity, it is not adversely affected by direct gas supply arrangements entered into by its customers.

The Company's natural gas distribution business is seasonal, with higher sales in the colder winter months because a substantial portion of the gas it delivers is used for space heating

purposes, resulting in lower sales in warmer months. As a result, 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.

Western System

Transmission Pipeline System

The Company's transmission pipeline system in the Western system service area connects with the British Columbia pipeline system operated by Spectra Energy near Summit Lake, British Columbia, and extends 587 kilometres to the west coast of British Columbia at Prince Rupert. The pipeline between Summit Lake and Terrace has been partially paralleled, or looped, with a second line to increase throughput capacity. The Company also owns and operates over 300 kilometres of lateral transmission pipelines extending into the various communities served by the Company, the most significant being dual lines extending approximately 57 kilometres into Kitimat.

Five compressor units maintain pressure on the Company's transmission pipeline system: two located at Summit Lake and one each at Vanderhoof, Burns Lake and Telkwa. The total installed rating of the compressor units is 16,120 kilowatts (21,610 horsepower). The sustainable capacity of the transmission pipeline system, with the present compressor and looping configuration, is approximately $3,260 \times 10^3 \text{ m}^3$ (115 MMcf) per day. With the closure of the Methanex methanol/ammonia facility in Kitimat the Company deactivated its compressor stations at Vanderhoof and Telkwa, as well as 53 miles of 10 inch pipeline and 33 miles of 6 inch pipeline. These facilities will continue to be maintained for potential future use, but are not forecast to be utilized in 2011.

If service commences under the TSA with LNG Partners, 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 ceased operations in 2005 would 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. 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.

Distribution System and Franchise Agreements

The Company owns and operates natural gas distribution facilities to deliver gas from its pipeline system to homes and businesses in the various communities located throughout the Western system service area. The Company's Western system's distribution system is comprised of approximately 1,180 kilometres of distribution pipelines.

The Company currently has exclusive franchise agreements with the municipalities of Prince Rupert, Port Edward, Kitimat, Terrace, Smithers, Burns Lake, Houston, Fraser Lake and Vanderhoof, entitling it to supply and distribute natural gas within those municipalities. Each of

the franchise agreements has an initial term of 21 years, expiring in 2011 (except in the case of Port Edward, where the agreement expires on October 5, 2031, and Prince Rupert and Fraser Lake, where both agreements expire in 2015), and is renewable at the option of either party for a further term of 21 years.

The Company also has operating agreements with the municipalities of Telkwa and Fort St. James that entitle it to install and operate gas distribution facilities in those municipalities. The initial term of each of these operating agreements has expired, and the Company is operating within ten year renewal terms which expire in 2021 and 2019, respectively. Each operating agreement provides for an unlimited number of ten year renewal terms, which take effect automatically on the expiry of the preceding renewal term. If the parties cannot agree on alterations to an operating agreement for a renewal term, the Commission may determine such alterations. Management does not foresee any issues with the renewal of any of the franchise and operating agreements.

Under all of the municipal franchise and operating agreements, the Company is required to pay the municipality an annual fee on gas sales within the municipality equal to 3 percent of the Company's gross revenue from sales to residential and commercial customers and 3 percent of the gross revenue from the sale of the first 328,000 GJ (approximately 300 MMcf) per year to any industrial customer.

The communities served by the Company's distribution system within its Western system service area had an estimated total population of approximately 84,300 in 2010.

Northeast System

Transmission and Distribution Facilities

The Company's Northeast system serves the Fort St. John and Dawson Creek area through connections with the Spectra Energy pipeline system at several locations. The Northeast system also connects with a pipeline owned by Canadian Natural Resources Limited ("CNRL") in two locations to obtain supply for the Fort St. John area, and with a producer's pipeline to serve the Dawson Creek area and the Spectra Energy pipeline system near Chetwynd, British Columbia to serve the Tumbler Ridge area. The entire Northeast system consists of approximately 160 kilometres of transmission lines, 1,490 kilometres of distribution lines and a gas processing plant near Tumbler Ridge with a capacity of 120 10^3m^3 per day.

Franchise Agreements

Pacific Northern (N.E.) has exclusive franchise agreements with the District of Taylor and the cities of Dawson Creek and Fort St. John for 21-year terms, expiring in 2012, 2014 and 2018, respectively, as well as an operating agreement with the Village of Pouce Coupe which expires in 2016. The Dawson Creek and Fort St. John agreements provide for payment of a 3 percent fee on gross revenues from sales of gas to residential, commercial, public and institutional customers and 3 percent of the gross revenue from the sale of the first 328,000 GJ per year to any industrial customer. Pacific Northern (N.E.) operates its gas distribution facilities in the Tumbler Ridge area pursuant to a certificate of public convenience and necessity issued by the Commission. No franchise fees are payable to the municipality of Tumbler Ridge.

The franchise agreements with the City of Dawson Creek and the Village of Pouce Coupe are renewable for a further term of 21 years at the option of either party. The franchise agreements with the District of Taylor and City of Fort St. John give the municipalities the right to purchase the distribution system within the municipality on expiry of the franchise agreement, at the fair market value of the assets as a going concern.

The communities served by the Northeast system had a total population of approximately 59,000 in 2010.

Properties

Substantially all of the Company's transmission lines and lateral lines are located across Crown land or privately-owned property under rights-of-way granted by the Crown or the owners in perpetuity or for so long as they are used for pipeline purposes. Approximately three kilometers of main pipelines and approximately nine kilometers of lateral transmission pipelines cross reserves established under the *Indian Act* (Canada), for which the Company has appropriate land rights.

Within all the municipalities in which the Company distributes gas, distribution lines occupy municipal streets and lanes by authority granted to the Company under franchise or operating agreements or other regulatory approvals. River, highway and railway crossings have generally been constructed pursuant to orders or permits from appropriate authorities or owners. Compressor and metering stations are principally located on land owned by the Company in fee simple. The Company owns its local offices in Terrace, Prince Rupert, Kitimat, Burns Lake, Smithers, Dawson Creek, Tumbler Ridge and Fort St. John and leases office space in a number of other communities in its service area and in Vancouver.

All of the property and assets of the Company and Pacific Northern (N.E.) are subject to the lien of a deed of trust and mortgage dated as of April 15, 1982 between the Company and Computershare Trust Company of Canada, as trustee, as amended and supplemented from time to time, under which the Company's secured debentures have been issued.

Gas Sales and Transportation

Total natural gas deliveries were 9.5 PJ in 2010 compared with 12.1 PJ in 2009. Deliveries to large industrial sales and transportation customers decreased 57.6 percent from 2009 to 2010, primarily as a result of reduced deliveries to West Fraser which accounted for 20.4 percent of large industrial customer deliveries in 2010 compared to 66 percent in 2009. These reduced deliveries related to the lower demand and lower prices for forest products in North America throughout 2010 and the planned permanent shutdown of the paper mill (see "Closure of West Fraser Eurocan Paper Mill" under Trends and Competition). However, deliveries to other large industrial customers which accounted for the remaining 79.6 percent remained at similar levels in 2010 compared to 2009.

Deliveries to small industrial customers decreased by 10.4 percent compared to 2009. This was mainly due to lower consumption by small industrial customers in the forestry sector. Deliveries to residential customers in 2010 decreased by approximately 11 percent compared to 2009

mainly due to weather that was approximately 8 percent warmer compared to 2009. Deliveries to commercial customers also decreased in 2010 by approximately 12 percent from 2009 levels due to the warmer weather experienced in 2010.

The following table sets out, by customer category, certain information relating to the Company's gas sales and deliveries for the past three years:

	<u>2010</u>	<u>2009</u>	<u>2008</u>
Deliveries: (in TJ)			
Residential	2 858	3 221	3 210
Commercial	2 704	3 081	3 007
Small industrial.....	2 747	3 066	3 049
Large industrial.....	1 178	2 777	3 276
Total energy delivered	<u>9 487</u>	<u>12 145</u>	<u>12 542</u>
Customers at Year End:			
Residential	34,163	33,910	33,862
Commercial	5,181	5,142	5,190
Small industrial.....	59	58	58
Large industrial.....	2	3	3
Total number of customers	<u>39,405</u>	<u>39,113</u>	<u>39,113</u>
Revenue and Operating Margin:			
<i>(\$ in thousands)</i>			
Sales Revenue			
Residential	37,642	39,783	44,937
Commercial	25,927	29,600	31,974
Small industrial.....	3,152	3,830	4,486
Large industrial			
Rio Tinto Alcan.....	858	2,477	4,025
BC Hydro.....	—	—	—
Off system sales	14,988	14,839	32,508
Total sales revenue.....	<u>82,567</u>	<u>90,529</u>	<u>117,930</u>
Cost of gas	(44,113)	(57,239)	(86,124)
Operating margin from sales	<u>38,454</u>	<u>33,290</u>	<u>31,806</u>
Transportation Revenue			
Residential.....	—	—	—
Commercial.....	1,814	1,330	1,794
Small industrial	3,093	2,709	2,832
Large industrial			
West Fraser.....	1,971	2,114	2,273
Rio Tinto Alcan.....	1,736	980	906
BC Hydro	130	98	89
Off system sales	—	—	—
Total revenue and operating margin from transportation services.....	<u>8,744</u>	<u>7,231</u>	<u>7,894</u>
Other Revenue			
Methanex termination payment	—	5,466	6,592
Miscellaneous revenue	3,853	905	423
Total other revenue	<u>3,853</u>	<u>6,371</u>	<u>7,015</u>
Total operating margin	<u>51,051</u>	<u>46,892</u>	<u>46,715</u>

Large Industrial Customers

Overview

The Company currently has a transportation service agreement with Rio Tinto Alcan and delivers gas to its other large industrial customer, BC Hydro, under an interruptible sales and service agreement for standby power generation at BC Hydro's facility in Prince Rupert.

The Company had a transportation service agreement with West Fraser that was to have expired on December 31, 2013; however West Fraser served notice to terminate its agreement with the Company effective November 30, 2010 (see "The Company – General Development of the Business – Closure of West Fraser Kitimat B.C. Paper Mill").

Under the terms of its agreement with Rio Tinto Alcan, the Company provides firm gas transportation service to Rio Tinto Alcan's Kitimat aluminium facility, with a toll established by the Commission from time to time. The agreement specifies a daily contract demand volume of 30.8 10³m³ (1.1 MMcf) and a minimum monthly charge equal to 85 percent of the monthly contract demand volume multiplied by the firm transportation toll. The agreement also provides for interruptible sales of gas to Rio Tinto Alcan. The initial term of the agreement ended November 1, 2004, but the agreement automatically continues in effect from contract year to contract year unless either party gives one contract year notice of termination. No termination notice has been given.

During 2010, deliveries to Rio Tinto Alcan accounted for 9.1 percent of the Company's total gas deliveries and 2.7 percent of revenues. Rio Tinto Alcan has produced aluminium for export from its Kitimat facility since 1952.

In August 2006, Rio Tinto Alcan announced its intention, subject to certain conditions, to modernize the Kitimat facility through an approximate US\$2.5 billion investment, which would increase Rio Tinto Alcan's annual global primary aluminium production by more than 3 percent. Due to lower demand and prices for aluminum and the global economic downturn, Rio Tinto Alcan slowed the pace of work on the modernization project. Activity on the modernization project picked up in 2010 with the announcement in August 2010 and December 2010 of additional investment US\$50 million and US\$300 million, respectively to be spent on preconstruction activities.

BC Hydro

The Company delivers gas to its other large industrial customer, BC Hydro, under an interruptible sales and service agreement for electric power generation at BC Hydro's facility in Prince Rupert. This generation plant has typically been used by BC Hydro as a stand-by facility with an annual gas requirement in the range of 24 TJ to maintain the facility in a ready to operate mode. Deliveries totaled 71 TJ in 2010, compared to 14 TJ in 2009. In both years, BC Hydro operated its station on an intermittent basis to ensure the station was in a ready to operate mode in case of an emergency. However, the higher deliveries in 2010 compared to 2009 were due to BC Hydro operating the facility at the request of the Company to facilitate the use of an in-line pipeline inspection tool.

Methanex

Transportation service to Methanex was provided pursuant to an agreement that was to expire on October 31, 2009. On August 30, 2005, Methanex gave notice of termination of the agreement. Pursuant to the terms of the agreement, Methanex made a termination payment to the Company of approximately \$23.3 million on February 28, 2006, the effective date of the termination. This termination payment was approximately equal to the net present value of future firm contract payment obligations, net of the Company's avoidable costs if Methanex were no longer operating. Under the terms of a negotiated settlement with registered intervenors and approved by the Commission on November 17, 2005, the termination payment was recorded as an interest bearing credit deferral, and was amortized into income over the period March 1, 2006 to October 31, 2009. The Company sought and obtained Commission approval in its 2010 revenue requirements application to recover \$5.5 million in response to the impact of the full amortization in rates of the Methanex termination payment as of October 31, 2009. The basis for recovery is the same as set out in the Company's 2006 application.

Natural Gas Supply

All of the Company's residential customers, most of its commercial customers and a number of its smaller industrial customers continue to rely on the Company for arrangement of their gas supply, and pay tariffs which include the Company's gas supply commodity and delivery costs. The commodity cost of gas is passed through to customers in rates and subsequent rate adjustments, after approval by the Commission.

The Company's large industrial customers, the majority of its small industrial customers and a number of commercial customers arrange for delivery of their gas supply requirements by the Company. These customers contract for gas transportation service on the Company's pipeline systems. In addition, some of the Company's smaller commercial customers purchase their gas supply requirements directly from gas marketers. Since the Company earns income from the distribution of natural gas and not from the sale of the commodity, the Company's distribution margin is not adversely affected by this practise. Some of these customers also purchase gas from the Company to supplement their gas supply as may be required from time to time and subject to gas supply availability from the Company.

To meet the requirements of its core market customers, natural gas is purchased by the Company under various gas purchase contracts. Contracted gas that is surplus to the requirements of these customers may be sold either on an interruptible basis to industrial customers or sold to other purchasers who are not the Company's transmission or distribution customers ("off system sales"). Any profit or loss realized on off system gas sales is deferred for future recovery from, or refund to, the Company's sales customers.

Natural gas is purchased at prevailing market prices and passed through to customers without mark-up by the Company. The Commission reviews the gas commodity portion of the Company's rates on a quarterly basis to ensure close alignment with the prevailing market prices for natural gas. Any variances in gas commodity prices paid by the Company from those included in current retail rates are deferred for subsequent refund to or recovery from customers. To moderate the variability of the gas supply commodity prices paid, the Company uses financial

instruments and fixed price supply contracts under a gas price management plan that is filed with the Commission on an annual basis.

For 2010, approximately 42 percent of gas purchases were hedged pursuant to the Company's gas price management plan. A gas supply contracting plan is prepared annually and filed with the Commission for review prior to finalizing annual gas purchase arrangements. The gas contracting plan is designed to ensure the Company has adequate gas supplies to meet the requirements of its customers on the coldest day of the year, normally referred to as "the peak day". Contracted gas that is surplus to customer requirements on any particular day is sold into other markets at prevailing market prices through off-system gas sales. Most of the Company's contracted gas supply is produced in British Columbia.

Most of the gas purchased by the Company from its gas suppliers is taken from the pooled gas stream available from the Spectra Energy pipeline system. This includes all of the supply to the Company's transmission line serving its Western system service area and approximately 76 percent of the supply for the Fort St. John and Dawson Creek service areas.

In addition to the supply from the Spectra Energy system, the Fort St. John system incorporates two interconnections with CNRL's West Stoddart Pipeline, providing 34 percent of that system's requirements in 2010. In Dawson Creek, approximately 5 percent of the required supply in 2010 was received from a local producer of sweet (pipeline quality) gas at a point where its system intersects the Company's transmission line. In Tumbler Ridge, all of the gas supply is obtained in the form of raw gas production from CNRL and the Company operates its own gas processing facilities.

In 2010, gas was purchased under a number of short-term seasonal, base load and spot gas supply arrangements. Short-term gas supply contracts are in keeping with current industry practices.

Customer Additions

There was a net increase of 292 in the ending number of customers as at December 31, 2010 compared the prior year end. The Northeast system service area experienced a net gain of 479 customers and the Western system service area experienced a net loss of 187 customers.

During 2010, the Company added approximately 100 new customers in the community of Tomslake, B.C., located in the Dawson Creek division of the Northeast system service area, as it finalized the new gas distribution system in this rural area. In addition, the Company added an additional 69 new service installations in this area during 2010.

In the Western system service area there are few remaining candidates for conversion to natural gas in the existing building stock and limited opportunity remains to extend gas mains into unserved rural areas. Further, the Company was anticipating some customer loss in Kitimat and surrounding areas due to the closure of West Fraser's Kitimat paper mill (see "The Company – General Development of the Business – Closure of West Fraser Kitimat B.C. Paper Mill").

Government Regulation

General

The Company is subject to regulation under the *Utilities Commission Act* (British Columbia) (the "Utilities Act"). Pursuant to the Utilities Act, the Commission regulates the business of public utilities, including the construction and operation of major facilities, the issuance of securities, determination of rates for the sale and transportation of gas, and the terms and conditions of service. In approving rates, the Commission must determine that such rates reflect a fair and reasonable charge for service of the nature and quality furnished by the Company to its customers, and that such rates are sufficient to yield the Company a fair and reasonable compensation for its services, including a fair and reasonable return upon the value of its property.

The Company is also subject to regulation under the *Pipeline Act* (British Columbia) in respect of the construction, operation and maintenance of its transmission pipeline facilities.

Rate Regulation

The Company's rates are determined by the Commission on the basis of annual forecasts of both the cost of service and throughput for the Company's transmission and distribution system. The cost of service consists of the cost of purchased gas and the cost of transporting all gas delivered through the Company's system, including operating, maintenance and administrative expenses, depreciation of facilities, income and other taxes and a return on rate base. Rate base is composed of the depreciated book value of plant in service, plus unamortized deferred charges, plus allowance for working capital, less deferred income taxes. The rate base is approved annually by the Commission for rate making purposes, including approval of annual capital additions forecast by the Company. Forecast capital additions are usually approved as applied for by the Company with minor modifications. If the actual cost of forecast capital additions exceeds the amount approved by the Commission, the excess cost may be subject to a prudence review by the Commission depending on the extent actual costs exceed the amount approved by the Commission. The Commission determines the allowable return on rate base after considering a variety of factors, including the degree of risk associated with the Company's business and the cost of capital.

A key component of the cost of capital is the after-tax return on the common equity component of the capital structure (the "ROE"). Commencing in 1994, the Commission used a formula to determine, on an annual basis, the ROE applicable to a benchmark low-risk utility based on forecast long term Government of Canada bond rates plus a risk premium. The Company's risk profile is compared by the Commission to the benchmark low-risk utility to determine the Company's utility-specific risk premium relative to the ROE applicable to the benchmark low-

risk utility. The Company's utility-specific risk premium is then added to the benchmark low-risk utility risk premium to determine the ROE which the Company is allowed to include in rates each year.

The Commission has approved a number of deferral accounts for the Company to record costs and revenues for various items for recovery from customers, or refund to customers, over a future time period. The general purpose of a deferral account is to keep the Company or its customers whole in respect of the subject matter of the deferral account. Two main deferral accounts apply to all divisions of the Company:

- Gas Cost Variance Account ("GCVA") – The commodity cost of gas included in customer rates is based on a forecast of the gas market prices the Company expects to pay to gas suppliers over the ensuing 12 month period. The difference between the forecast gas cost the Company charges its customers and the actual gas cost incurred by the Company is recorded by the Company in the GCVA. The balance in this account is reviewed by the Company and the Commission every quarter. If actual gas costs exceed forecast gas costs, the difference will be recovered from customers by an increase in future rates. If actual gas costs are lower than forecast gas costs, the difference will be refunded to customers through a reduction in future rates. In this way, customers, over time, pay the same cost for gas as is paid by the Company.
- Rate Stabilization Adjustment Mechanism ("RSAM") – The Company forecasts the revenue it will receive from customers based on an annual forecast of gas deliveries to customers. As it is not possible to forecast deliveries to customers with complete accuracy for a variety of reasons, including the effect of weather on gas consumption, the Company is allowed by the Commission to record the difference between forecast and actual revenue realized from residential and small commercial customers in the RSAM deferral account. If actual deliveries exceed forecast deliveries, the resulting revenue difference will be recorded in the RSAM deferral account and refunded to customers in future rates. If actual deliveries are less than forecast deliveries, the resulting revenue difference will be recorded in the RSAM deferral account and recovered from customers in future rates.

Revenue requirements applications for the three service areas (the Western system service area and the two service areas in the Northeast system) are submitted to the Commission, generally on an annual basis. The Northeast system contains two divisions for rate making purposes. One division comprises the Fort St. John/Dawson Creek service area, and the other division the Tumbler Ridge service area. The Commission may consider these applications through a public hearing process (either oral or written), or through negotiations with the customers under alternate dispute resolution processes. Settlements are subject to final approval by the Commission.

2011 Revenue Requirements Applications

In late November 2010, the Company filed its 2011 revenue requirements applications for all divisions. The applications sought approval to increase rates on an interim basis effective January 1, 2011 pending the Commission's review of the applications. The Commission approved interim rates effective January 1, 2011 at the levels set forth in the applications.

The Company amended the applications in mid-January 2011 to reflect changes to the treatment of a number of deferral accounts in response to being advised that the Commission had directed other utilities to reflect changes in response to the deferred implementation of IFRS effective January 1, 2012, rather than January 1, 2011 (see “Changes in Accounting Policies – Future Accounting Pronouncements”). The 2011 revenue deficiency projected for the Western system under the amended application is approximately \$2.7 million.

PNG (N.E.)’s Fort St. John/Dawson Creek division has a forecast revenue deficiency of close to \$2.4 million while the Tumbler Ridge division 2011 forecast revenue deficiency is negligible. The applied for delivery charge increases compared to October 2010 delivery rates for an average residential customer in each service area are 8.3 percent for the Western system (\$72 per year), 25.4 percent for the Fort St. John/Dawson Creek division (\$93 per year) and 0.5 percent for the Tumbler Ridge division (\$2 per year).

A negotiated settlement process is expected to be conducted with respect to the 2011 revenue requirements applications in the second quarter of 2011.

Rate Base and Common Equity

The following table summarizes, for each of the Company’s three service areas, the rate base, common equity component of rate base and the after tax rate of return on common equity approved by the Commission for the three years ended December 31, 2010 and as applied for under the Company’s 2011 revenue requirement application:

	<u>2011*</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>
Western system:				
Rate base.....	\$133,080	\$130,173	\$131,358	\$132,938
Common equity component.....	45.0%	45.0%	40.0%	40.0%
Allowed return on common equity	10.15%	10.15%	9.63%	9.27%
Fort St. John/ Dawson Creek division:				
Rate base.....	\$39,228	\$38,599	\$36,363	\$33,486
Common equity component.....	40.0%	40.0%	36.0%	36.0%
Allowed return on common equity	9.90%	9.90%	9.38%	9.02%
Tumbler Ridge division:				
Rate base.....	\$2,218	\$1,708	\$1,565	\$1,465
Common equity component.....	40.0%	40.0%	36.0%	36.0%
Allowed return on common equity	10.15%	10.15%	9.63%	9.27%

* Estimate, subject to Commission approval.

Credit Facilities

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.

The first risk management facility has a single financial covenant requiring the Company's debt leverage not to exceed 65 percent. The Company added a second risk management facility in January 2010. This facility 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 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 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. Under either facility, to the extent the credit exposure of the facility provider exceeds \$20 million (where exposure is calculated by the facility provider using its standard methodology), the Company is required to provide cash collateral for the exposure in excess of \$20 million. Neither hedge facility provider is obligated to enter into any transactions with the Company under the terms of the facilities. Each hedge transaction must be agreed between the parties. The provider of one of the risk management facilities has documented its intention not to enter into transactions under its facility in the event that the provider's exposure would exceed \$15 million.

Short-term Debt

In November 2010, the Company completed a renegotiation and extension of its bank operating facility. Under this facility, \$25.0 million is available for working capital purposes. The November 2010 amendments included deletion of the previous borrowing base limitation to availability under the operating facility. As a result, the \$25.0 million is available to the Company at all times subject to a requirement that borrowings be reduced to zero for 30 days each calendar year. The Company covenants under the facility to maintain its debt leverage at 65% or less. At December 31, 2010 the Company's actual debt leverage was 50.4 percent. The operating line is collateralized by a pledge of the Company's accounts receivables and inventories.

Borrowings under the operating facility bear interest at prime rate or bankers' acceptance rates plus an applicable credit spread. The renegotiated terms included reduced credit spreads to 1 percent over prime and 2.25 percent over bankers' acceptances, previously 1.5 percent and 3 percent respectively, as well as a reduction in the stand-by fee to 0.35 percent from 0.5 percent. The renewed 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 December 31, 2010, the actual utilization of the operating line was \$8.6 million.

Long-term Debt

On February 2, 2010 the Company amended its revolving term facility to increase the amount available under the facility to \$35 million (previously \$20 million) and to extend its maturity date to January 30, 2015. Concurrent with these amendments, the fees and interest rate spreads under the facility were amended to reflect current market conditions. The standby fee on the facility was increased to 50 basis points on undrawn amounts and the interest rate spread over the Canadian Dealer Offered Rate ("CDOR") was increased to 307.5 basis points from 132.5 basis

points. The facility contains a financial covenant requiring the Company's debt leverage not to exceed 65 percent and, if the Company's secured debt rating is less than BBB (low) or the Company has no debt rating, the Company must maintain an interest coverage of 2.0 times or higher using earnings before interest, income taxes and expenditures on the KSL Project to a maximum of \$10 million.

\$16.0 million was outstanding under the revolving term facility at December 31, 2010 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.

Environment, Health and Safety Matters

In the ordinary course of its operations, the Company is required to comply with applicable federal and provincial environmental laws. The Company makes expenditures on environmental protection in the operations of its gas pipeline and distribution systems, its renewable energy facilities and in the construction of new facilities. For the regulated operations these expenditures are recovered from customers in the rates and tolls approved by the Commission. In addition, there are environmental assessment regimes at both the provincial and federal levels that are structured to identify and mitigate potential environmental consequences of projects, such as the Company's renewable energy projects, prior to commencement.

The Company has created an environmental, health and safety management system that is designed to identify environment, health and safety ("EHS") issues, mitigate those issues and monitor performance. Programs have been implemented to ensure adherence to the Company's EHS policies. The programs include environmental training for specific employee groups, implementation of environmentally sound construction practices including on-site environmental monitoring where appropriate, and a continuing focus on corporate due diligence. Audits are periodically done on the EHS management system. The Board of Directors oversees the Company's EHS responsibilities through the Environment, Health and Safety Committee and members of the Company's executive management team have a portion of their variable compensation tied to EHS performance.

Greenhouse gas ("GHG") emissions are the main environmental issue for the Company, particularly because of the level of uncertainty surrounding initiatives at various levels of government, provincially, federally and internationally, to address this issue. In Canada, the federal government has delayed its implementation of a proposed national GHG cap-and-trade system until 2012 in order to harmonize with U.S. plans. As a partner in the Western Climate Initiative ("WCI"), B.C. has enacted legislation and developed regulations aligned with the principles agreed to by the WCI partners. The Mandatory Reporting of Greenhouse Gas Emissions Regulation requires facilities and/or entities with emissions in most source categories to submit data on greenhouse gas emissions to the Minister of Environment, which will provide a foundation for the development and implementation of a cap and trade system and other climate policies to reduce greenhouse gases. Under the regulation, facilities emitting more than 10,000 tonnes CO_{2e} per year are required to report their annual GHG emissions beginning with the 2010 calendar year, with the first report due April 1st, 2011. The Company expect to file its 2010 GHG emissions report prior to this date. Based on the applicable emissions thresholds set out in

the draft federal and current provincial regulations, the Company expects its compliance obligations to be small.

The Company has processes in place to monitor the ongoing integrity of its transmission pipeline systems to ensure protection of the public and the environment by demonstrating that all transmission pipelines are suitable for continued safe and reliable service. A key aspect of these processes focuses on the internal inspection of the pipeline using in-line inspection tools and subsequent repair activities that arise from the information gathered.

The Company began implementing in-line inspection programs on its transmission pipeline in 1989. The in-line inspection program is predominantly based on running a Magnetic Flux Leakage (“MFL”) tool that is primarily used to detect metal loss due to external and internal corrosion. This tool can also detect certain other potential defects including defects in the pipe wall such as laminations, and certain types of weld defects. After the MFL tool runs are complete, the resulting information is processed and evaluated to determine which areas need rehabilitation. The 2010 inspection activity involved the inspection of a combined length of approximately 70 kilometers of 219mm and 273mm diameter pipeline. The 2010 inspection activity also included a number of small diameter laterals for which suitable in-line inspection tools are not available. Consequently close interval surveys were used to validate their integrity. The results from this year’s work did not give rise to any significant issues. The Company intends to continue its inspection program in 2011 and into the foreseeable future on an annual basis.

Expenditures related to compliance with environmental laws and protection initiatives are not material to the Company’s consolidated results of operations, cash flow or financial position and, based on current laws, facts and circumstances, are not expected to have a material impact in the future. In addition, prudent operating and capital costs incurred for these matters are recoverable in customer rates for the regulated facilities. The Company believes its operations are in compliance with applicable environmental laws, rules regulations and guidelines in all material respects.

Employees

At December 31, 2010, the Company had 107 employees, comprised of 77 unionized and 30 non-unionized employees. All unionized employees are members of the International Brotherhood of Electrical Workers (the “Union”). The Company’s current collective agreement with the Union expires on October 31, 2012.

RISK FACTORS

The Company faces the following strategic, financial and operational risks in carrying out its business:

Usage Risk and Impact of Changes in Economic Conditions

Natural gas competes with other forms of energy available to the Company's customers and end-users, including electricity, wood and coal and, in the case of certain industrial customers, wood waste. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, economic conditions, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors affect the demand for natural gas in the Company's service areas. In addition, because electricity prices in British Columbia for residential and certain other customer classes have been set based primarily on the historical average cost of production, they have been artificially low compared to market priced natural gas. This distortion in pricing signal may be addressed in response to the British Columbia government's Energy Plan electricity conservation goals.

Over the past several years the average amount of natural gas consumed by residential customers has declined. This decline is attributable to a number of factors, including the replacement of older heating equipment by newer, more efficient equipment, more energy efficient housing, and energy conservation measures in response to higher gas prices and poor economic conditions in the Western system region.

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

Acquisition and Integration Strategies

As part of its business strategy, the Company may pursue strategic acquisitions. There can be no assurance that the Company will find additional attractive acquisition candidates or succeed at effectively maintaining the integration of any businesses acquired in the future.

Acquisitions involve a number of risks, including: (a) the possibility that the Company, as a successor owner, may be legally and financially responsible for liabilities of prior owners; (b) the possibility that the Company may pay more than the acquired company or assets are worth; (c) the possibility of incurring additional expenses associated with completing an acquisition and amortizing any acquired intangible assets; (d) the difficulty of integrating the operations and

personnel of an acquired business; (e) the challenge of implementing standard controls, procedures and policies throughout an acquired business; (f) the inability to integrate, train, retain and motivate key personnel of an acquired business; and (g) the potential disruption of the Company's ongoing business and the distraction of management from its day-to-day operations. These risks and difficulties, if they materialize, could disrupt the Company's ongoing business, distract management, result in the loss of key personnel, increase expenses and otherwise have an adverse effect on the Company's business, results of operations and financial performance.

In addition, as the Company seeks to grow and diversify its operations, the risk profile of its business may change. There may be greater economic exposure and more "at risk" capital with the expansion of the Company's business activities. While the Company will pursue growth initiatives by incurring risk that is felt to be justified by expected returns and managed effectively, there can be no assurances that such risks can be avoided.

McNair Creek Acquisition and Integration

The Company entered into the renewable energy business through its acquisition of the McNair Creek "run of river" facility which closed on April 19, 2010. The Company will continue to spend time and resources to manage and integrate this new business into its current operations. Significant due diligence was performed prior to the closing of the acquisition, but management cannot provide assurance that it will not be incurring additional risks associated with this new business. In particular, the financial performance of the facility is directly related to levels of precipitation in the catchment area of McNair Creek which can vary from year-to-year.

Liquidity, Cash Flow and Capital Availability Risks

The Company has several credit facilities, including a \$25 million operating line, a \$35 million 5-year term revolving credit facility and two risk management facilities each secured by the pledge of a \$20 million debenture issued by the Company. The operating line, which is available for working capital requirements, is subject to a financial covenant which may act to restrict the amount the Company can borrow under the operating line. The financial covenant requires the Company to maintain a debt to capitalization ratio of 65 percent or less. At December 31, 2010 the Company's debt to capitalization ratio was just over 50 percent. See "Management's Discussion and Analysis – Capital Resources – Short Term Debt". At December 31, 2010 the Company had utilized \$4.6 million of the operating line by way of overdraft and utilized an additional \$4.0 million for letters of credit issued under the line to secure the Company's obligations under its unfunded supplemental retirement plan as well as certain obligations of McNair Creek Hydro Limited Partnership. The letters of credit reduce the amount available under the operating line by their face value. The operating line is collateralized by a charge on the Company's accounts receivables and inventories.

As noted above under 'Credit Facilities' the 5-year term revolving credit facility contains a financial covenant requiring the Company's debt leverage not to exceed 65 percent and, if the Company's secured debt rating is less than BBB (low) or the Company has no debt rating, the Company must maintain an interest coverage of 2.0 times or higher using earnings before interest, income taxes and expenditures on the KSL Project to a cumulative maximum of

\$10 million. These financial covenants may act to restrict the amount the Company can borrow under the 5-year term revolving credit facility.

The Company purchases gas for resale to its gas sales customers and passes through the commodity cost of gas to those customers without mark-up. The rates charged to gas sales customers are based, in part, on projected gas supply prices. The Company's liquidity requirements can be affected by delays between increases or decreases in the cost of gas purchased by the Company and regulatory approval of rate adjustments to reflect the cost increases or decreases. The Company utilizes its risk management facilities to enter into financial derivative contracts which help mitigate the volatility of its gas purchase costs.

Under either facility, to the extent the credit exposure of the facility provider exceeds \$20 million (where exposure is calculated by the facility provider using its standard methodology), the Company is required to provide cash collateral for the exposure in excess of \$20 million. Neither hedge facility provider is obligated to enter into any transactions with the Company under the terms of the facilities. Each hedge transaction must be agreed between the parties. The provider of one of the risk management facilities has documented its intention not to enter into transactions under its facility in the event that the provider's exposure would exceed \$15 million. That risk management facility also has a single financial covenant requiring the Company's debt leverage not to exceed 65 percent.

The second risk management facility was added in January 2010. This facility 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 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.

Any constraint on the Company's ability to access capital, including a credit downgrade, may negatively impact its investment and development activities, capital expenditures and hedging program.

Commodity Price and Supply Risks

The commodity cost of natural gas can be highly volatile. The Company's average cost of natural gas in 2010 was approximately 14.3 percent lower than in 2009 and 30.6 percent lower than in 2008. When prices are low, the prospects of fuel-switching and increased energy conservation to other energy sources that can be more cost competitive pose a lesser risk. Fluctuations in the price of natural gas may increase the Company's working capital financing requirements and related costs for accounts receivable, and may give rise to higher bad debt costs.

Adequate supplies of natural gas may not be available to satisfy committed obligations as a result of economic events, natural occurrences and/or failure of a counterparty to perform under a gas purchase contract.

Potential for Termination of Large Industrial Contracts

In 2010, approximately 12.4 percent of energy deliveries were made to the Company's large industrial customers, representing approximately 9.1 percent of the consolidated operating margin of the Company.

The initial term of the Company's agreement with Rio Tinto Alcan ended November 1, 2004, but the agreement automatically continues in effect from contract year to contract year unless either party gives twelve months' notice of termination. No termination notice has been given. During 2010, deliveries to Rio Tinto Alcan accounted for 9.1 percent of the Company's total gas deliveries and 2.7 percent of revenues. See "Business of the Company – Large Industrial Customers".

The Company had a transportation service agreement with West Fraser that was to have expired on December 31, 2013; however West Fraser served notice to terminate its agreement with the Company effective November 30, 2010. See "Business of the Company – Large Industrial Customers".

The Company's ability to negotiate new contracts and to renegotiate existing contracts could be impacted by factors it cannot control, including reduced demand due to higher gas prices, the financial strength of major customers and the availability of alternative energy sources.

The Company's service area is dependent upon industrial customers for its economic stability. These customers produce commodities that are subject to world commodity fluctuations and are impacted by current deteriorating economic conditions. The Company's gas deliveries to these customers have been and may in the future be affected by their ability to continue to operate in negative economic conditions and during sustained periods of low commodity prices, as has transpired in the past. A prolonged decline in a sector affects all customer classes. For example, in the Western system service area many of the Company's industrial customers are involved in the forest sector. The forest sector has been facing significant issues with low lumber prices, the mountain pine beetle infestation and the continuing strength of the Canadian dollar in 2010. A prolonged decline in the forest sector could negatively impact gas deliveries to a lumber mill, as well as negatively impacting delivery requirements of commercial and residential customers who directly or indirectly provide services to that mill.

Regulatory Risks

The Company's business and assets are subject to regulation by the Commission. Changes in the regulatory environment may be beyond the Company's control and may impact the viability of the business, including the Company's ability to sustain or increase its profitability.

As part of the regulatory process, the Company maintains a number of deferral accounts including the GCVA, the RSAM and accounts for pipeline repair and rehabilitation. See "Business of the Company – Government Regulation".

The GCVA is utilized to record variances in the Company's actual purchase cost of gas relative to the gas supply cost recovery charge included in customers' rates. At times, the gas supply

cost recovery charges included in customers' rates can be below the actual purchase cost of gas, resulting in a balance in the account which must be recovered from customers in future rates.

The Company's rates are set on the basis of forecast gas deliveries using normal heating degree-days. To the extent that actual degree days are less than normal (that is, the weather is warmer than normal), revenues may be less than forecast. The revenue for residential and small commercial customers is protected by the RSAM deferral account approved by the Commission to record differences between forecast and actual deliveries. When deliveries to customers are less than forecast, there may be significant balances in the account which are subject to recovery in future rates to customers.

The Commission requires the Company to record certain temporary pipeline repair and rehabilitation costs in deferral accounts for amortization into customer rates over a period of ten years on the basis that the customers benefit from such expenditures over that period of time.

The recovery of the Company's accumulated deferral accounts has an impact on the Company's liquidity requirements. Recovery of the deferral accounts through rates charged to customers is dependent upon regulatory approval and the ability to set rates high enough to recover such balances while maintaining the competitiveness of retail gas prices, and is therefore at risk.

Facility and Insurance Risks

The Company carries on business in a geographic area of British Columbia where a large portion of its pipeline transmission system is located in difficult terrain and where outages have been experienced in the past. Depending on circumstances, any such outages in the future may result in loss of revenues or increased maintenance costs.

The Company maintains insurance against exposure to the physical loss of its pipeline, compressors and other above ground facilities, as well as loss of earnings insurance relating to revenues from its large industrial customers. Based on past insurance claims by the Company for damage to its pipeline caused by slides, washouts and other natural events, its deductible for pipeline breaks is relatively high at \$2 million per event. Depending on the number and severity of any future outages, the financial impact on the Company could be material.

These identified facility and insurance risks could affect the Company's liquidity and regulatory approval would be required for the Company to recover related costs through future rate adjustments.

Environmental and Safety Risks

The Company is required to comply with existing environmental laws and regulations. It is possible that increasingly strict environmental laws, regulations and enforcement policies, and potential claims for damages and injuries to property, employees, other persons and the environment resulting from current or discontinued operations, could result in substantial costs and liabilities in the future. In particular, the Company could be exposed to significant operational disruptions and environmental liability in the event of an accident involving natural gas. The Company believes that it has taken all reasonable and prudent steps to minimize its exposure in the case of safety or environmental incidents.

Based on the applicable GHG emissions thresholds set out in the draft federal and current provincial regulations, the Company expects its compliance obligations to be small. However, as the federal and provincial regulations remain in development, it is not possible at this time to assess the full extent of their impact on the Company. In addition, the effects of climate change on the Company's service territories over the long term may manifest themselves in changes to customers' consumption patterns, as well as to changes in the level and nature of geotechnical and hydrological threats to the Company's pipeline systems. The Company recognizes the entire spectrum of influences that climate change may exert on its operations and continues to monitor, and influence as appropriate, related policies, regulations and developments.

Renewable Energy Business Risks

The revenue earned by McNair is proportional to the amount of electrical energy generated from the facility. The electricity generation is directly related to the levels of precipitation in the catchment area of McNair Creek which can vary from year to year. This facility is also subject to risks related to premature wear or failure, defects in design, material or workmanship and longer than anticipated down times for maintenance and repair. These risks are partially mitigated by the proven nature of the technology employed, and the regular maintenance and the design of the facility.

All of the electricity generated by the McNair Creek facility is sold to BC Hydro under a long-term energy purchase agreement. This energy purchase agreement will expire in 2024 and there can be no assurance that the Company will be able to renegotiate or enter into another energy purchase agreement on terms that are commercially reasonable.

Derivatives Risk

The Company utilizes derivative and other financial instruments in connection with the management of gas supply and may in the future use these instruments for the management of interest rates. The Company enters into forward, future, swap, fixed price and option contracts to manage the impact of market fluctuations on assets, liabilities or other contractual commitments. The Company could, however, incur financial losses in the future as a result of market or price volatility or the failure of a counterparty to a derivative instrument. These risks could affect the Company's liquidity and regulatory approval would be required for the Company to recover related costs through future rate adjustments. Furthermore, because the valuation of these financial instruments can involve estimates, changes in the assumptions underlying these estimates can occur, changing the Company's valuation and potentially resulting in financial losses.

Human Resources Risks

Most of the employees of the Company are members of a union. See "Business of the Company – Engineering and Operations - Employees". Labour disruptions associated with the collective bargaining process could impact the Company's ongoing operations. In addition, the Company is dependent on maintaining its ability to attract and retain employees with the requisite skill and capabilities to operate in the complex and competitive energy industry.

Employee Future Benefits Plan Risk

The Company has a defined benefit pension plan for the majority of its employees and retirees. Contributions to the plan are established by actuarial valuations prepared every three years and filed with the appropriate regulatory authorities. If the plan experiences negative returns it may result in large contribution requirements.

The latest actuarial valuation report as at December 31, 2009 was completed during the third quarter of 2010. It states that the Company has an unfunded liability on a going concern basis of \$1.4 million and a solvency deficit of \$5.4 million. As a result of the solvency deficiency, the Company must make special contributions for past service to amortize this deficit as well as normal cost contributions. The Company is required to make annual funding contributions of an estimated \$2.1 million to its pension plan as determined by the latest actuarial valuation report. In 2009, the funding contribution was \$1.3 million.

First Nations Matters

First Nations groups have claimed rights and title over a substantial portion of the lands on which the Company's facilities in British Columbia and the gas supply areas served by those facilities are located. The existence of these claims, which range from the assertion of rights of limited use to aboriginal title, has given rise to some uncertainty regarding access to these lands. As well, approximately three kilometres of the Company's main pipeline and approximately nine kilometres of lateral transmission pipelines cross reserves established under the *Indian Act* (Canada). The impact upon the Company of treaties or settlements with First Nations groups is uncertain.

Share Price Volatility

A number of factors could influence the volatility in the trading of the Common Shares, including changes in the economy or in the financial markets, and in particular the current global financial issues, industry-related developments, the impact of changes in the Company's operations and regulatory decisions affecting the Company, including decisions relating to return on equity and deemed equity. In addition, variations in earnings estimates by securities analysts and the market prices of the securities of companies in the same industry as the Company may also lead to fluctuations in the trading price of the Common Shares.

Transition to IFRS

The Company makes use of specific policies under Canadian GAAP to account for its rate-regulated activities. This includes the use of regulatory assets and regulatory liabilities which allow the economic impact of rate-regulated activities to be recognized in the financial statements in a manner consistent with the timing by which amounts are reflected in customer rates.

Effective January 1, 2012, the Company is required to report under IFRS, including the presentation of IFRS-compliant comparative figures for fiscal 2011. Under existing IFRS guidance and practice, the Company's current accounting policies for rate-regulated activities are

not allowed. Financial results under IFRS will be prepared without the use of regulatory deferral accounts and this may result in increased volatility in the Company's reported financial results.

DIVIDENDS

The following tables set forth information concerning the payment of dividends by the Company for the last three fiscal years:

	<u>2010</u>	<u>2009</u>	<u>2008</u>
Dividends per share			
- common	\$1.14	\$0.96	\$0.88
- preferred	\$1.69	\$1.69	\$1.69

On February 8, 2010, the Board of Directors approved an increase in the quarterly dividend to \$0.28 per Common Share and on October 26, 2010 the Board of Directors approved a further increase in the quarterly dividend to \$0.30 per Common Share. The Company pays a semi-annual dividend of \$0.84375 per preferred share on January 1 and July 1 of each year.

DESCRIPTION OF CAPITAL STRUCTURE

The Company's authorized share capital consists of 6,020,000 Common Shares with a par value of \$2.50 each, 1,400,000 cumulative redeemable junior preferred shares with a par value of \$10 (the "Junior Preferred Shares") and 200,000 6 ³/₄ percent cumulative redeemable preferred shares with a par value of \$25 each (the "Preferred Shares"). There are 3,615,144 Common Shares, no Junior Preferred Shares and 200,000 Preferred Shares issued and outstanding at March 3, 2011.

Common Shares

Each Common Share entitles the holder to one vote per share at all meetings of shareholders of the Company, except meetings at which only holders of another specified class of shares are entitled to vote. The Common Shares are the only issued voting securities of the Company and it has no securities outstanding that can be converted into voting or equity securities.

Cumulative Redeemable Junior Preferred Shares

The Junior Preferred Shares were issued in connection with a specific transaction, and to the extent issued have been redeemed and cancelled. No further Junior Preferred Shares will be issued.

6 ³/₄ Percent Cumulative Redeemable Preferred Shares

The Preferred Shares are entitled to the payment of fixed cumulative preferential cash dividends at the rate of 6 ³/₄ percent per annum on the amounts from time to time paid up thereon as when declared by the board of directors of the Company, have priority in the event of the liquidation,

dissolution or winding up of the Company over the Common Shares, are non-voting and are redeemable at the option of the Company at \$26 per share plus any accrued and unpaid dividends at the date of redemption. The Company may not create shares ranking prior to the Preferred Shares but may create and issue other shares ranking on parity with those shares.

Ratings

On May 17, 2010, DBRS confirmed the Company's secured debt ratings at BBB (low) with a stable trend.

In its ratings report dated May 17, 2010, DBRS noted the following key challenges for the Company in arriving at the ratings for the Company's long term debt and preferred shares:

- Economic conditions in the Company's Western system service area remain challenging;
- Potential loss of residential and commercial customers in the Western system service area;
- Deemed equity component viewed as low for business risk profile; and
- Competitiveness of natural gas versus alternative fuel sources

In its press release also dated May 17, 2010 DBRS noted:

"The rating reflects Pacific Northern Gas' stable financial profile and the continued supportive regulatory environment in British Columbia. In August 2009, DBRS changed the trends on the debentures and preferred share ratings to stable from negative following the favourable regulatory decision which included a negotiated rate increase that incorporated the impact of the end of the Methanex termination payment amortization in October 2009. The full impact of the negotiated settlement and the subsequent regulatory decision to increase the low-risk utility benchmark return on equity (ROE) to 9.50% from 8.47% are both expected to be positive for Pacific Northern Gas' financial profile in the near to medium term.

Pacific Northern Gas continues to maintain a stable credit profile with debt-to-capitalization under 50%, cash flow-to-debt of 17% and an EBIT coverage ratio of 2.6 times. While these financial metrics are generally consistent with those seen among higher-rated utilities in Canada, Pacific Northern Gas' rating remains low-investment grade due to its higher level of business risk, largely attributable to a challenging service territory. Economic conditions in the Western system remain challenging as many of the company's industrial customers are engaged in the forestry sector which has been challenged globally. Pacific Northern Gas has stated that prolonged decline in the forestry sector could negatively impact gas deliveries to lumber mills, as well as commercial and residential customers who directly or indirectly provide service to such mills. This weakness has been offset somewhat by growth in the Northeast service area, which has benefitted from strong activity in the oil and gas sector."

Long-term debt rated BBB (ranging from BBB(low) to BBB(high)) is considered by DBRS to be of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities.

Preferred shares rated Pfd-3 (ranging from Pfd-3(low) to Pfd-3(high)) are also considered by DBRS to be of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. Pfd-3 ratings generally correspond with companies whose senior bonds are rated in the higher end of the BBB category.

With respect to the stable trend, DBRS's rating policies published on their web site at www.dbrs.com include the following statements:

- “Rating trends provide guidance in respect of DBRS's opinion regarding the outlook for the rating in question, with rating trends falling into one of three categories – “Positive”, “Stable” or “Negative”. The rating trend indicates the direction in which DBRS considers the rating is headed should present tendencies continue, or in some cases, unless challenges are addressed.”
- “Generally, the conditions that lead to the assignment of a Negative or Positive Trend are resolved within a twelve month period. However, in some instances, new factors emerge which may cause the Positive or Negative Trend to be maintained, even as the original factors become clarified or resolved.”

A security rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating organization.

MARKET FOR SECURITIES

The Common Shares and the 6 3/4 percent Cumulative Redeemable Preferred Shares of the Company are listed on the TSX. The following table sets out the price ranges and volume traded for each month of the fiscal year ended December 31, 2010 for the common shares and the 6 3/4 percent preferred shares:

Common shares:	High	Low	Volume
January	\$21.49	\$ 18.75	121,277
February	22.85	21.00	124,702
March	23.96	22.50	134,832
April	24.44	22.65	118,294
May	24.18	23.10	103,062
June	28.00	23.55	97,724
July	26.49	24.25	39,999
August	27.43	25.00	52,891
September	26.95	25.47	29,911
October	27.38	26.35	35,389
November	29.00	27.15	67,383
December	30.00	28.00	54,370

Preferred shares:	High	Low	Volume
January	\$27.00	\$26.60	2,000
February	26.25	26.25	200
March	27.00	26.25	2,695
April	26.50	26.25	1,800
May	26.50	26.10	550
June	25.90	25.90	175
July	26.27	26.25	840
August	26.28	25.89	508
September	26.25	26.08	500
October	26.73	26.50	1,400
November	26.94	26.50	2,727
December	26.94	25.75	2,862

LEGAL PROCEEDINGS

There are no legal proceedings material to the Company to which the Company or any of its subsidiaries is a party or of which any of their respective property is the subject matter, and there are no such proceedings known to management of the Company to be contemplated.

DIRECTORS AND OFFICERS

The following tables set out the names of the directors and officers, as well as other pertinent information, including: principal occupation or employment, province and country of residence, all major positions and offices presently held in the Company, the year first elected a director of the Company and the approximate number of shares of the Company beneficially owned, directly or indirectly, or over which control or direction is exercised by such person. The directors serve for a term from the date of election until the next annual meeting or until their respective successors have been elected or appointed. The directors and officers as a group own, directly or indirectly, or exercise control or direction over approximately 4.5 percent of the issued and outstanding common shares of the Company.

Directors

Name, Principal Occupation and Other Information	Beneficial Ownership or Control of Common Shares at March 3, 2011	Number of DSU's at March 3, 2011	Purchase Value of Common Shares and DSU's ⁽⁶⁾
Robert F. Chase: Chair of the Board; Corporate Director; resident in British Columbia, Canada; a director of the Company since April 26, 1995 ^{1,4}	2,000	8,939	\$201,706
Wayne M. Bingham: Executive Vice-President and Chief Financial Officer, Superior Plus Corp.; resident in Alberta, Canada; a director of the Company since April 26, 2007 ^{2,3}	4,300	1,589	\$106,731
Roy G. Dyce: President and Chief Executive Officer of Pacific Northern Gas Ltd.; resident in British Columbia, Canada; a director of the Company since April 29, 1982	83,168	--	Note 6
Diane M. Fulton: Vice President, Chief Investment Officer, Vancouver Foundation (a not-for-profit community foundation); resident in British Columbia, Canada; a director of the Company since August 8, 2005 ^{1,2}	Nil	3,948	\$73,642
Robert B. Johnston: Executive Vice President and Chief Strategy Officer, The InterTech Group (a holding company and operator of diverse, global group of companies) ; resident in South Carolina, U.S.A.; a director of the Company since June 9, 2008 ⁴	5,000 Note 7	4,044	\$163,215
David G. Unruh: Corporate Director; resident in British Columbia, Canada; a director of the Company since March 21, 2002 ^{3,4}	Nil	4,998	\$92,314
Arthur H. Willms: Corporate Director; resident in British Columbia, Canada; a director of the Company since April 28, 1983 ^{1,4}	Nil	4,091	\$76,270
Janet P. Woodruff: Vice President and Special Advisor, BC Hydro (a Crown corporation that plans, operates and maintains the province's publicly owned electrical transmission system); resident in British Columbia, Canada, a director of the Company since February 16, 2006 ^{2,3}	Nil	3,540	\$67,268

(1) Member of the Executive Committee

(2) Member of the Audit Committee

(3) Member of the Environment, Health and Safety Committee

(4) Member of the Compensation and Corporate Governance Committee

(5) Effective January 1, 2007, the Company established a Deferred Share Unit Plan (the "DSU Plan") to align the interests of the directors with those of the shareholders. Under the DSU Plan, directors may designate a percentage (25, 50, 75 or 100 percent) of his or her total compensation to be issued as DSU's. In addition, the Board of Directors approved recommended share ownership guidelines for directors equal to three times the annual retainer (currently \$20,000) to be attained within five years of the Company's 2007 Annual Meeting or, for new directors, within (i) five years from the date of such director's appointment if at an Annual Meeting, and (ii) within five years from the date of the next Annual Meeting following such director's appointment if such appointment is not at an Annual Meeting. The ownership guidelines are measured by the purchase value of shares and DSU's. Each of the directors is on target to achieve the recommended share ownership.

(6) Mr. Dyce's shares have been acquired primarily through stock option exercises over a number of years and the purchase value is difficult to calculate. At the closing price of the Company's shares on March 3, 2011 of \$27.00, these shares had a market value of \$2,245,536.

(7) Mr. Johnston also owns 100 of the Company's Preferred Shares.

Officers

Name, Position and Other Information	Beneficial Ownership or Control of Common Shares at March 3, 2011
<u>Robert F. Chase</u> Chairman of the Board British Columbia, Canada	2,000
<u>Roy G. Dyce</u> President and Chief Executive Officer British Columbia, Canada	83,168
<u>Greg B. Weeres</u> Vice President, Operations and Engineering, British Columbia, Canada	27,938
<u>Janet P. Kennedy</u> Vice President, Finance British Columbia, Canada	2,100
<u>Kevin R. Teitge</u> Vice President, Corporate Development and Treasurer British Columbia, Canada	18,585
<u>Craig P. Donohue</u> Director, Regulatory Affairs & Gas Supply and Assistant Secretary British Columbia, Canada	19,638
<u>Kelly E. Stark-Anderson</u> Secretary British Columbia, Canada	Nil

During the last five years, all of the directors and officers have been employed in various capacities by the Company or by the companies indicated opposite their names except: Ms. Woodruff was Chief Financial Officer and Vice President Systems Development and Performance of Vancouver Coastal Health from 2003 to September 2007, and has held senior executive positions including Interim President with BC Transmission Corporation from October 2007 to 2010; Mr. Bingham was Executive Vice President and Chief Financial Officer for Finning International Inc. from 2003 to 2006; Ms. Fulton was Executive Director – Investments of the Faculty Pension Plan of the University of British Columbia from 1999 to October 2008; Ms. Kennedy was a financial consultant to Terasen Inc. from May, 2006 to September, 2007 and was Director, Financial Planning and Projects for Terasen Inc. from March 2002 to November 2005; and Ms. K.E. Stark-Anderson is engaged in the practice of law through KSA Law Corporation and from 2002 to 2006 was Assistant General Counsel and Corporate Secretary of Westcoast Energy Inc.

To the knowledge of management, except as described below, none of the individuals named above is at the date hereof or has been within the past ten years: (i) a director, chief executive officer or chief financial officer of any company that, while such individual was acting in such capacity, was the subject of or was the subject of an event that resulted in, after such individual

ceased to act in such capacity, an order within the meaning of Form 51-102F5 of National Instrument 51-102 - *Continuous Disclosure Obligations*; (ii) a director or executive officer of any company that, while such individual was acting in such capacity or within a year of such individual ceasing to act in such capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (iii) been bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or became subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold any of his or her assets:

Mr. Chase was a director of New West Energy Services Inc. (“New West”) when, on September 5, 2006, a cease trade order was issued against New West by the British Columbia Securities Commission for failure to file its financial statements within the prescribed time. The default was rectified and the order was rescinded on November 9, 2006.

To the knowledge of management, none of the individuals named above has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable security holder in deciding whether to vote for such individual as a director of the Company.

Audit Committee

Charter of the Audit Committee

The Terms of Reference of the Audit Committee of the Board of Directors of the Company is attached as Schedule A to this Annual Information Form.

Composition of the Audit Committee

Ms. Woodruff, Ms. Fulton and Mr. Bingham served as members of the Audit Committee from January 1, 2010 to April 29, 2010; on April 29, 2010 Mr. Chase was appointed to the Audit Committee in Ms. Woodruff’s stead to serve with Ms. Fulton and Mr. Bingham. Effective July 27, 2010 Ms. Woodruff resumed her role as a member and Chair of the Committee and Mr. Chase stepped down from the Committee. Each member who served on the Audit Committee during the last fiscal year is independent as defined under Multilateral Instrument 52-110 “Audit Committees”.

Relevant Education and Experience

Each member who served on the Audit Committee during the last fiscal year is financially literate as defined under Multilateral Instrument 52-110 “Audit Committees”.

Ms. Woodruff, the Chair of the Committee, is a chartered accountant and holds a Masters of Business Administration from York University. She has experience in public practice and, for

nearly fifteen years, held various senior executive and financial management positions in a large Canadian company prior to becoming Chief Financial Officer of Vancouver Coastal Health Authority, subsequently Chief Financial Officer followed by Interim President of BC Transmission Corporation, and now Vice President and Special Advisor of BC Hydro. Ms. Woodruff has also completed the Directors' Education Program at the Institute of Corporate Directors and earned the ICD.D designation.

Ms. Fulton holds a Masters of Business Administration from York University and is a member of the Board of Directors, and the Audit Committee of Ten Peaks Coffee Company Inc. She is an investment advisor to the Investment Committee of the Insurance Corporation of British Columbia as well as advisor to the Investment Committee of Pacific Blue Cross and B.C. Life. She has over twenty years experience in investment banking and investment fund management. Ms. Fulton has also completed the Directors' Education Program at the Institute of Corporate Directors and earned the ICD.D designation.

Mr. Bingham has over 30 years experience in financial and capital markets. Prior to attaining his current position as Executive Vice President and Chief Financial Officer of Superior Plus Corp., Mr. Bingham served as Executive Vice President and Chief Financial Officer at Finning International Inc. and Ontario Power Generation. In addition, he has held many senior executive and management positions in strategy, financing, compliance, risk management, treasury and supply chain operations. Mr. Bingham holds a Bachelor of Commerce from Laurentian University and a Chartered Accountant designation.

Mr. Chase is a chartered accountant and has over 30 years of experience as the top executive or Chief Financial Officer for a number of companies whose activities included: investment/merchant banking; commercial banking; oil and gas exploration and development; mining exploration and development, forest products; and port terminal operations. He is a Director of New West Energy Services Inc. and a Director and Audit Committee member of several other TSX, TSX-V and private companies involved in oil and gas activities, mining exploration, financial services and forestry operations.

Reliance on Certain Exemptions

Since January 1, 2010, the Corporation has not relied on the exemptions contained in sections 2.4, 3.2, 3.3(2), 3.4, 3.5, 3.6, 3.8 or Part 8 of MI 52-110. Section 2.4 provides an exemption from the requirement that the Audit Committee must pre-approve all non-audit services to be provided by the external auditor, where the total amount of fees related to the non-audit services are not expected to exceed 5% of the total fees payable to the external auditor in the fiscal year in which the non-audit services were provided. Sections 3.2, 3.3(2), 3.4, 3.5, 3.6 and 3.8 provide exemptions relating to the independence and financial literacy requirements for the composition of the Audit Committee in certain circumstances. Part 8 permits a company to apply to a securities regulatory authority for an exemption from the requirements of MI 52-110, in whole or in part.

Audit Committee Oversight

At no time since January 1, 2010 was a recommendation of the Audit Committee to nominate or compensate an external auditor not adopted by the Board.

Pre-Approval Policies and Procedures

The Terms of Reference for the Audit Committee provide that the Audit Committee is required to pre-approve the retention of the independent auditor for any non-audit service and the fee for such service. The Committee may satisfy the pre-approval requirement in subsection 2(g) if:

- i) the aggregate amount of all the non-audit services that were not pre-approved constitutes no more than five per cent of the total amount of revenues paid by the Corporation to its independent auditors during the fiscal year in which the services are provided;
- ii) the services were not recognized by the Corporation at the time of the engagement to be non-audit services; and
- iii) the services are promptly brought to the attention of the Committee and are approved, prior to the completion of the audit, by the Committee or by one or more members of the Committee to whom authority to grant such approvals has been delegated by the Committee.

The Committee may delegate to one or more independent members the authority to pre-approve non-audit services in satisfaction of the requirement above provided that the pre-approval of non-audit services by any member to whom authority has been delegated must be presented to the full Committee at its first scheduled meeting following such pre-approval.

External Auditor Service Fees

Except as noted, all dollar amounts herein are in Canadian dollars. Fees for professional services rendered by Deloitte & Touche LLP to the Company were:

	Audit Fees	Audit-Related Fees⁽¹⁾	Tax Fees⁽²⁾	All Other Fees
2010	\$182,700	\$91,605	—	—
2009	\$166,700	\$67,605	—	—

⁽¹⁾ Audit-related fees pertain to quarterly reviews in 2009 and 2010, consultation on accounting matters, audit of the Company's savings plan and McNair Creek Hydro Limited Partnership, and IFRS consultation.

⁽²⁾ Tax services include assistance with the preparation of corporate income tax returns and review of tax planning strategies.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

The Company had no material transactions with related parties during 2008, 2009 or 2010.

MATERIAL CONTRACTS

The following are the contracts, other than contracts entered into the ordinary course of business of the Company, that are material to the Company and that were entered after January 1, 2002 and which are still in effect:

- (1) Indemnity Agreements entered into by the Company in favour of each of the directors and officers;
- (2) Agreement dated February 4, 2011 among the Company, Apache Canada Ltd. and EOG Resources Canada Inc. for the sale by the Company of its interest in PTP (see “The Company - General Development of the Business – KSL Project – Sale of PTP”)

These contracts have been filed on www.sedar.com.

TRANSFER AGENT

The Company’s transfer agent is Computershare Investor Services Inc. of Canada with registers maintained in Vancouver, Calgary, Regina, Winnipeg, Toronto and Montreal.

EXPERTS

The independent auditors of the Company are Deloitte & Touche LLP.

ADDITIONAL INFORMATION

Additional information concerning the Company can be found at www.sedar.com. Additional information, including information as to directors’ and officers’ remuneration and indebtedness, principal holders of the Company's securities, options to purchase securities and securities authorized for issuance under equity compensation plans, is contained in the Management Information Circular which is provided to shareholders prior to the Company’s 2011 Annual Meeting of Shareholders. Additional financial information is provided in the Company's consolidated financial statements for the year ended December 31, 2010. Management’s Discussion and Analysis for the year ended December 31, 2010 is incorporated by reference into and forms an integral part of this annual information form. Copies of these documents may be obtained upon request from the Secretary, Pacific Northern Gas Ltd., 950 -1185 West Georgia Street, Vancouver, British Columbia, V6E 4E6.

SCHEDULE "A"

PACIFIC NORTHERN GAS LTD. (the "Company")

AUDIT COMMITTEE

TERMS OF REFERENCE

PURPOSE

The overall purpose of the Audit Committee is to ensure that: (i) the Company's management has designed and implemented an effective system of internal financial controls, (ii) to review and report on the integrity of the consolidated financial statements of the Company, (iii) to review the Company's compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and disclosure of material facts, and (iv) to monitor and oversee the independent auditors' qualifications, independence and activities.

COMPOSITION, PROCEDURES AND ORGANIZATION

1. The Board of Directors of the Company (the "Board"), at its organizational meeting held in conjunction with each annual general meeting of the shareholders, shall appoint the members and the Chair of the Committee for the ensuing year. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee.
2. The Committee shall consist of at least three members of the Board all of whom shall be independent as determined in accordance with applicable securities laws, rules, regulations and guidelines ("Securities Laws"). All Committee members shall be financially literate. For this purpose, financial literacy shall mean the ability of a member to read and understand a set of financial statements that present a breadth and level of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company's financial statements. At least one member should have accounting or related financial expertise.
3. If the Chair is not present at any meeting of the Committee, one of the other members of the Committee present at the meeting shall be chosen by the Committee to preside at the meeting.
4. The Vice President, Finance of the Company shall be the secretary of the Committee, unless otherwise determined by the Committee.
5. The Committee shall meet at least four times annually on such dates and at such locations as may be determined by the Chair of the Committee and may also meet at any other time or times on the call of the Chair of the Committee, the independent auditors or any two of the other members.

6. The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak and to hear each other.
7. Any two Directors may request the Chair to call a meeting of the Committee and may attend at such meeting or inform the Committee of a specific matter of concern to such Directors, and may participate in such meeting to the extent permitted by the Chair of the Committee.
8. Notice of the time and place of every meeting shall be given in writing or by e-mail or facsimile communication to each member of the Committee at least 24 hours prior to the time fixed for such meeting; provided, however, that a member may in any manner waive a notice of a meeting and attendance of a member at a meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.
9. The Vice President, Finance shall develop and set the Committee's agenda, in consultation with the Chair and other members of management. The agenda and information concerning the business to be conducted at each Committee meeting shall, to the extent practical, be communicated to the members of the Committee sufficiently in advance of each meeting to permit meaningful review.
10. At the invitation of the Chair, one or more officers or employees of the Company may, and if required by the Committee shall, attend a meeting of the Committee. The independent auditors shall receive notice of and have the right to attend all meetings of the Committee. The Chief Executive Officer shall be invited to attend all meetings, except executive sessions and private sessions with the independent auditors.
11. The Committee shall fix its own procedure at meetings, keep records of its proceedings and report to the Board when the Committee may deem appropriate (but not later than the next meeting of the Board).
12. The Committee, when it considers it necessary or advisable, may retain, at the Company's expense, outside consultants or advisors to assist or advise the Committee independently on any matter within its mandate. The Committee shall have the sole authority to retain and terminate any such consultants or advisors or any search firm to be used to identify director candidates, including sole authority to approve the fees and other retention terms for such persons.
13. The internal auditors and the independent auditors shall have a direct line of communication to the Committee through the Chair and may bypass management if deemed necessary. The independent auditors shall report to the Committee and are ultimately accountable to the Board and the Committee, as representatives of the shareholders.
14. The Committee, through its Chair, may contact directly the independent auditors, the internal auditors, if any, and any employee of the Company as it deems necessary.

15. In discharging its responsibilities, the Committee shall have full access to all books, records, facilities and personnel of the Company, to the Company's legal counsel and to such other information respecting the Company as it considers necessary or advisable in order to perform its duties and responsibilities.

ROLES AND RESPONSIBILITIES

1. Overall Duties and Responsibilities

The overall duties and responsibilities of the Committee shall be as follows:

- a) to assist the Board in the discharge of its responsibilities relating to the quality, acceptability and integrity of the Company's accounting principles, reporting practices and internal controls;
- b) to assist the Board in the discharge of its responsibilities relating to compliance with disclosure requirements under applicable Securities Laws, including approval of the Company's annual and quarterly consolidated financial statements together with the Management's Discussion and Analysis;
- c) to establish and maintain a direct line of communication with the Company's independent auditors and internal auditors (if any) and assess their performance;
- d) to ensure that the management of the Company has designed, implemented and is maintaining an effective system of internal controls; and
- e) to report regularly to the Board on the fulfillment of its duties and responsibilities.

2. Independent Auditors

The duties and responsibilities of the Committee as they relate to the independent auditors shall be as follows:

- a) to recommend to the Board a firm of independent auditors to be engaged by the Company;
- b) to review, at least annually, with the independent auditors their independence from management, including a review of all other significant relationships the auditors may have with the Company and to satisfy itself of the auditors' independence, the experience and the qualifications of the senior members of the independent auditor team and the quality control procedures of the independent auditor.
- c) to review and approve the fee, scope, staffing and timing of the audit and other related services rendered by the independent auditors and ensure the rotation of the lead audit partner as required by applicable Securities Laws;
- d) to be responsible for overseeing the work of the independent auditors and reviewing the audit plan prior to the commencement of the audit;

- e) to approve the engagement of the independent auditors for the interim review of the unaudited financial statements of the Company and the fees for the interim reviews;
- f) to review with the independent auditors, upon completion of their audit and interim reviews:
 - i) contents of their report;
 - ii) scope and quality of the audit work performed;
 - iii) adequacy of the Company's financial and auditing personnel;
 - iv) co-operation received from the Company's personnel during the audit;
 - v) internal resources used;
 - vi) significant transactions outside of the normal business of the Company;
 - vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles and management systems;
 - viii) the quality, acceptability and integrity of the Company's accounting policies and principles;
 - ix) the non-audit services provided by the independent auditors;
 - x) the effect of regulatory and accounting initiatives as well as off-balance sheet structures on the Company's financial statements;and report to the Board in respect of the foregoing;
- g) to implement structures and procedures to ensure that the Committee meets the independent auditors on a regular basis in the absence of management in order to review any difficulties encountered by the independent auditors in carrying out the audit and to resolve disagreements between the independent auditors and management; and
- h) to pre-approve the retention of the independent auditor for any non-audit service and the fee for such service.

The Committee may satisfy the pre-approval requirement in subsection 2(g) if:

- i) the aggregate amount of all the non-audit services that were not pre-approved constitutes no more than five per cent of the total amount of revenues paid by the Company to its independent auditors during the fiscal year in which the services are provided;

- ii) the services were not recognized by the Company at the time of the engagement to be non-audit services; and
- iii) the services are promptly brought to the attention of the Committee and are approved, prior to the completion of the audit, by the Committee or by one or more members of the Committee to whom authority to grant such approvals has been delegated by the Committee.

The Committee may delegate to one or more independent members the authority to pre-approve non-audit services in satisfaction of the requirement in subsection 2(f) provided that the pre-approval of non-audit services by any member to whom authority has been delegated must be presented to the full Committee at its first scheduled meeting following such pre-approval.

3. **Internal Auditors**

The duties and responsibilities of the Committee as they relate to the Company's internal auditors are to:

- a) approve the engagement of the internal auditors and approve the fees for the internal audit function;
- b) periodically review the internal audit function with respect to the organization, staffing and effectiveness of the internal audit department;
- c) review and approve the internal audit plan; and
- d) review significant internal audit findings and recommendations, and management's response thereto.

4. **Internal Control Procedures**

The duties and responsibilities of the Committee as they relate to the internal control procedures of the Company are to:

- a) review the adequacy, appropriateness and effectiveness of the Company's policies and business practices which impact on the integrity, financial and otherwise, of the Company, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting, code of conduct and risk management;
- b) review compliance under the Company's Code of Business Ethics;
- c) review any issues between management and the independent auditors that could affect the financial reporting or internal controls of the Company;
- d) periodically review the Company's accounting and auditing policies, practises and procedures and the extent to which recommendations made by the internal auditors or by the independent auditors have been implemented; and

- e) Ratify membership of the Disclosure Committee, as required, as appointed by the Senior Officers of the Company.

5. **Public Filings, Policies and Procedures**

The Committee is charged with the responsibility to:

- a) review and approve for recommendation to the Board:
 - i) the annual report to shareholders, including the annual audited financial statements, with the report of the independent auditors, the Management's Discussion and Analysis and the impact of unusual items and changes in accounting principles and estimates;
 - ii) the interim report to shareholders, including the unaudited financial statements, the Management's Discussion and Analysis and the impact of unusual items and changes in accounting principles and estimates;
 - iii) earnings press releases;
 - iv) the annual information form;
 - v) prospectuses; and
 - vi) other public reports and public filings requiring approval by the Board;and report to the Board with respect thereto;
- b) review regulatory decisions as they relate to the Company's consolidated financial statements;
- c) ensure adequate procedures are in place for the review of the Company's disclosure of financial information extracted or derived from the Company's financial statements, other than the disclosure described in subsection 5(a) above, and periodically assess those procedures;
- d) review with management, the independent auditors and if necessary with legal counsel, any litigation, claim or other contingency, including tax assessments, that could have a material affect upon the financial position or operating results of the Company and the manner in which such matters have been disclosed in the consolidated financial statements;
- e) review with management and with the independent auditors any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of management that may be material to financial reporting;

- f) review with management and with the independent auditors (i) all critical accounting policies and practises to be used by the Company in preparing its financial statements, (ii) all material alternative treatments of financial information within GAAP that have been discussed with management, ramifications of the use of these alternative disclosures and treatments, and the treatment preferred by the independent auditor, and (iii) other material communications between the independent auditor and management, such as any management letter or schedule of unadjusted differences;
- g) review general accounting trends and issues of auditing policy, standards and practices which affect or may affect the Company;
- h) review the appointments of the Vice President, Finance, and any key financial executives involved in the financial reporting process;
- i) establish procedures for:
 - i) the receipt, retention and treatment of complaints received by the Company regarding accounting, internal controls, or auditing matters; and
 - ii) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.
- j) review and approve the issuer's hiring policies regarding employees and former employees of the present and former independent auditors of the Company;
- k) review and approve related party transactions.

6. **Pension and Savings Plans**

The Committee is charged with the responsibility to:

- a) Approve the Statements of Investment Policies and Procedures for the Employees' Retirement Plan and other Plans as required and any amendments required thereto;
- b) Appoint the auditors, review the scope of the audit plan and review and approve the audited financial statements for the Employees' Retirement Plan, the Supplemental Executive Retirement, the Employee Savings Program, the Group RRSP and the non-pension post-retirement benefits (collectively, the "Plans");
- c) Receive a report from the Pension and Savings Plan Committee (the "PSPC") after each of its meetings and report to the Board thereon;
- d) Receive semi-annually a report from the PSPC including (i) a summary of the activities of the PSC during the relevant period; (ii) a summary and evaluation of the investment performance of the funds associated with the Plans (the "Funds") for the applicable period; (iii) where there has been any change in any Investment

Manager during the relevant period, a summary of the factors leading up to the decision for such change, a report on the process that was undertaken to implement such change and a summary of the factors that influenced the decision of the Committee in selecting any new Investment Manager; and (iv) where there has been any change in any third party providers of pension-related services during the relevant period (other than changes in Investment Managers), including actuaries, auditors, pension consultants and outsourcers of pension administration, a report on such change; and report to the Board thereon.

- e) Receive an annual report from the PSPC including (i) the audited financial statements of the Plans and the Funds; (ii) a summary of the changes in the liabilities of the Plans with sensitivity analysis to interest rates, demographic factors and any other factors that may be indicated from time to time; (iii) The Statement of Investment Policy and Procedures for each of the Funds, containing such amendments as have been recommended by the PSPC.

7. **Calendar**

The Committee will develop a calendar of activities, attached as Appendix A, to be undertaken by the Committee for each ensuing year and to submit the calendar in the appropriate format to the Board of Directors on an annual basis.

APPENDIX A

AUDIT COMMITTEE

CALENDAR OF ACTIVITIES

	<u>Mar</u>	<u>April</u>	<u>July</u>	<u>Oct</u>
Review and Approve Financial Statements and Reports:				
• Financial Statements	✓	✓	✓	✓
• Interim Report, including MD&A		✓	✓	✓
• Annual Report, including MD&A	✓			
• Annual Information Form	✓			
• Review Major Accounting Policies and Significant Estimates	✓	✓	✓	✓
• Consider Changes in Accounting Principles and Whether Industry/Standards are Being Followed	✓	✓	✓	✓
• Consider Unresolved Differences of Opinion Between Management and the Auditor	✓	✓	✓	✓
External Auditors:				
• Review Scope of Audit and Audit Plan			✓	
• Discuss Audit Report and Findings	✓			
• Review Recommendations and Response to Audit Report	✓			
• Receive Interim Review Report		✓	✓	✓
• Review Auditor Independence	✓	✓	✓	✓
• Review Cooperation and Services Provided by Management	✓	✓	✓	✓
• Recommend Appointment of Auditors	✓			
• Approve Audit Fees			✓	
• Approve Interim Review Fees	✓			
• Meeting with Auditors - without Management	✓	✓	✓	✓
• Review Non-Audit Services	✓	✓	✓	✓

	<u>Mar</u>	<u>April</u>	<u>July</u>	<u>Oct</u>
Risk Management and Control:				
• Review Effectiveness of Internal Audit Function, Review the Internal Audit Plan and Approve Internal Audit Fees		✓		
• Review Internal Audit Findings	✓		✓	
• Review of Disclosure Controls and Procedures	✓	✓	✓	✓
• Review Report on Disclosure Risk Assessment	✓			✓
• Annual Assessment of Compliance with the Code of Business Ethics	✓			
• Review of Deferred Charges (including an Annual Review of Accounting Issues)	✓	✓	✓	✓
• Receive Report on Derivatives	✓	✓	✓	✓
• Adequacy of Allowance for Doubtful Accounts	✓	✓	✓	✓
• Review of Incidents Raised through the Whistleblower Program	✓	✓	✓	✓
• Assessment of Adequacy of Insurance Coverage	✓			
• Annual Tax Review		✓		
• Annual Review of Compliance with Legal and Regulatory Responsibilities	✓			
• Annual Review of Delegation of Authority to Management and of Management's Compliance	✓			
Pension and Savings Plans Committee:				
• Review Minutes of Meetings of PSPC	✓	✓	✓	✓
• Review Semi-Annual Report from PSPC	✓			✓
• Review Annual Report from PSPC		✓		
• Approve Appointment of Auditors and Fees and Review Scope of Audit for the Funds		✓		
• Approve Audited Financial Statements for the Pension and Savings Plans			✓	

	<u>Mar</u>	<u>April</u>	<u>July</u>	<u>Oct</u>
Other:				
• Adequacy of Complement in Accounting, Customer Billing and Finance				✓
• Assess Circumstances Adverse to the Company	✓	✓	✓	✓
• Review any Material Litigation	✓	✓	✓	✓
• Ratify members of Disclosure Committee (as necessary)	✓	✓	✓	✓
• Monitor Procedures for Reviewing Officers' Expenses				✓
• Review Terms of Reference and Calendar of Activities for Ensuing Year			✓	