



PACIFIC NORTHERN GAS LTD.

**ANNUAL
INFORMATION FORM**

For the 12 month period ended December 31, 2009

February 8, 2010

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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 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 its financial results are best measured by excluding the cost of gas which is flowed through to customer rates without a mark-up

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:

- The expected timing and results of regulatory decisions, including the Company’s Capital Structure and Equity Risk Premium Application (“the CAP/ROE Application”) (see “The Company – Business Strategy – Regulated Operations – Capital Structure and Equity Risk Premium Application”);
- The expected timing of and expenditures for development and construction of the Kitimat to Summit Lake Project (the “KSL Project”) (see “The Company – Business Strategy – KSL Project”);
- The expected timing for the commencement of transportation service for the potential Merrill Lynch Commodities Inc. (“Merrill Lynch”) floating liquefied natural gas (“LNG”) project and the cost of reactivating compressor stations to provide such service (see “The Company – Business Strategy – Regulated Operations – Capacity on the Western System” and “Business of the Company – Western System – Transmission Pipeline System”);
- Expectations for growth and opportunities in renewable energy generation;
- Expectations regarding the trends in customer numbers in the Western and Northeast service areas;
- Expectations regarding the impact of economic conditions on the Company’s performance and prospects for growth;
- Fair value of pension assets;

- Expectations for renewal of franchise and operating agreements;
- Expectations for the level of and source of funding for capital expenditure requirements; and
- Expectations regarding 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;
- forecasted gas deliveries;
- regulatory conditions, including decisions by the British Columbia Utilities Commission (the "Commission");
- the Company's future growth opportunities;
- the Company's ability to access capital;
- capital expenditure estimates, plans, schedules and activities and the development, construction, operations and cost of facilities and infrastructure;
- income tax considerations;
- operating risks and related insurance coverage and inspection and integrity systems; and
- general economic and competitive conditions.

By its nature, such forward-looking information is subject to various risks and uncertainties that are known and unknown, including those material risks discussed in this 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. (the “Company”) 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 office of the Company is 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. PNG Marketing Ltd. (currently inactive) was incorporated under the laws of British Columbia on October 17, 1986 and is a wholly owned subsidiary of the Company. Pacific Northern Gas Transition Ltd. (currently inactive) was incorporated under the laws of British Columbia on January 28, 2004 and is a wholly owned subsidiary of the Company.

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.

General Development of the Business

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.

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, continuing development of the KSL Project (as discussed below) and evaluating development and acquisition opportunities.

In respect of its strategy, the Company has concluded:

- It must grow profitably and increase its market capitalization in order to enhance shareholder value;
- While the Company remains encouraged regarding the prospects for the KSL Project, it cannot be completely reliant on that opportunity to meet its strategic targets;
- The KSL Project and the Merrill Lynch floating LNG project provide the most likely opportunities in the Company's service areas for any organic growth that would materially benefit the Company;
- Merger and acquisition opportunities are limited in the Canadian utility sector given PNG's small relative size; and
- It is important for the Company to seek growth opportunities in areas that complement its strengths and fit well within its existing risk profile.

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.

The Company can give no assurances that it will be successful in identifying, financing or realizing value from these opportunities.

The Company is also working to increase its dividend yield to shareholders to a level more consistent with other publicly traded utilities. In that regard, the Company announced a quarterly dividend increase in March, 2009 to \$0.23 per Common Share and a further increase in July, 2009 to \$0.25 per Common Share. On February 8, 2010, the Board of Directors increased the first quarter 2010 dividend on common shares to \$0.28 per share. The Company also implemented a normal course issuer bid ("NCIB") in March, 2009 which is discussed in greater detail below.

Regulated Business Opportunities

The Company is focused on ensuring that the regulatory environment allows it to earn a fair and reasonable return on investment and provide the required flexibility to react to market conditions

and preserve liquidity. In furtherance of this strategy, in 2009 the Company filed a capital structure and equity risk premium application and its 2010 revenue requirements applications. These initiatives are discussed in further detail under “Business of the Company – Government Regulation – Rate Regulation - Capital Structure and Equity Risk Premium Application” and “2010 Revenue Requirements Applications”. The Company also obtained Commission approval of a Letter Agreement that provides Merrill Lynch with an option to contract for 75 MMcf per day of firm gas transportation service using existing capacity on PNG’s Western pipeline system.

Capacity on the Western System

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

The Commission approved the Letter Agreement on April 23, 2009 and a \$1.5 million option fee was been released from escrow to PNG. Merrill Lynch had an exclusive option until December 31, 2009 to contract for firm gas transportation capacity for a two to five year primary term, with a right to renew for an additional two to five year term. A \$1 million option extension fee has been paid by Merrill Lynch to PNG to extend to June 30, 2010 the exclusive option granted by PNG to Merrill Lynch in March 2009. Merrill Lynch may extend the option period by up to three further six month periods, with payment of \$1 million for each extension. Negotiation of a transportation service agreement is ongoing and when finalized, it would be submitted to the Commission for acceptance as a filed tariff. The transportation service agreement would become effective following exercise of the option. However, in the unexpected event that the Commission does not accept the transportation service agreement, PNG would be required to refund the option fees to Merrill Lynch.

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

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

KSL Project

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

On January 13, 2010, Apache Corporation’s subsidiary Apache Canada Ltd. (“Apache”) acquired 51 percent of the Terminal. Apache also acquired a 25.5 percent interest in PTP from Galveston LNG Inc., the parent company of Kitimat LNG Inc. Kitimat LNG retained a 49 percent interest in the Terminal and Galveston LNG retained a 24.5 percent interest in PTP. Kitimat LNG Inc. previously announced the signing of a memorandum of understanding (“MOU”) with EOG Resources Canada to supply natural gas feedstock to the Terminal. Kitimat LNG Inc. also previously announced the signing of MOUs with Korea Gas Corporation and Gas Natural SDG, S.A., a Spanish based natural gas company, under which they would purchase LNG produced at the Terminal.

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

Subject to a number of conditions, construction of the KSL Project by PTP is planned to commence in 2012 for completion in 2014 when the Terminal is planned to begin operation. Conditions to construction include the securing of contracts for use of PTP’s transportation capacity, financing for construction of the KSL Project, and additional regulatory approvals for the KSL Project such as a Certificate of Public Convenience and Necessity (“CPCN”) from the Commission and other permits from the B.C. Oil and Gas Commission. The Company will be working to finalize transportation reservation agreements for the KSL Project by the second quarter of 2010 at which point it would prepare and file its CPCN application with the Commission. The Company can give no assurances that such agreements will be signed or other conditions will be satisfied or that construction of the KSL Project by PTP will proceed.

The Company’s share of development expenditures for the KSL Project in 2009 were approximately \$181,000 (\$127,000 after income taxes). Following environmental certification, expenditures on the KSL Project have been minimized and will continue to be expensed until suitable commercial arrangements for firm gas transportation services by PTP are in place at

which point development costs of the project would be capitalized. Assuming commercial arrangements for the KSL Project are completed by the second quarter of 2010, the Company expects its 50 percent share of KSL Project development costs in 2010 will total approximately \$5.5 million, of which approximately 90 percent would be capitalized. These costs would primarily relate to additional engineering and technical studies for the KSL Project pipeline.

Upon completion of the KSL Project, and subject to regulatory and shareholder approvals, the Company's existing mainline transmission system will be transferred to PTP and integrated with the KSL Project facilities. The Company would continue to own and operate its existing gas distribution systems, including its Customer Care Centre in Terrace.

Normal Course Issuer Bid

The Company commenced a normal course issuer bid through the facilities of the Toronto Stock Exchange on March 9, 2009. Under the approved program, the Company is permitted to purchase up to 300,000 of its own common shares through March 8, 2010. Subject to certain exemptions for block purchases, the Company was permitted to purchase up to 1,627 common shares each trading day through March 31, 2009 and is permitted to purchase 1,000 common shares each trading day thereafter. As at December 31, 2009, the Company had purchased 122,416 common shares at an average price of \$14.69 per share. Common shares purchased under the program are cancelled. Additional purchases of shares under the bid and renewal of the bid will depend on future market conditions.

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").

As a distributor of natural gas, the Company continuously monitors the competitiveness of its natural gas retail rates relative to alternative heating sources in its service area. The Company's current residential rates in all divisions are lower than the comparable residential electricity rate that became effective April 1, 2009. Declines in gas commodity prices payable by the Company during 2009 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 Corporation (“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 2010 Western system revenue requirements application is seeking Commission approval of a bundled average residential rate of \$19.58 per GJ effective January 1, 2010, including the current carbon tax of \$0.745 per GJ. This is approximately 6 percent less than the equivalent residential conservation electricity rate of \$20.88 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. PNG is participating with government stakeholder groups to keep apprised of potential cost effective demand side management initiatives that make sense for its customers.

Closure of West Fraser Eurocan Paper Mill

The forestry sector in the Western system continued to face challenges in 2009 including low lumber prices, the mountain pine beetle infestation and the strength of the Canadian dollar. These factors played a role in the decision by West Fraser to permanently close its Eurocan paper mill in Kitimat, B.C. The decision was announced on October 28, 2009 and the mill closed down at the end of January 2010. PNG has a transportation service agreement with West Fraser which specifies a daily contract demand volume of 6.0 MMcf per day that expires on December 31, 2013. Under the terms of its transportation agreement, West Fraser pays PNG an annual demand charge of approximately \$2.1 million and is entitled to cancel its obligations by providing PNG with a termination payment that would recover almost 80 percent of the lost revenues under the remaining term of the agreement.

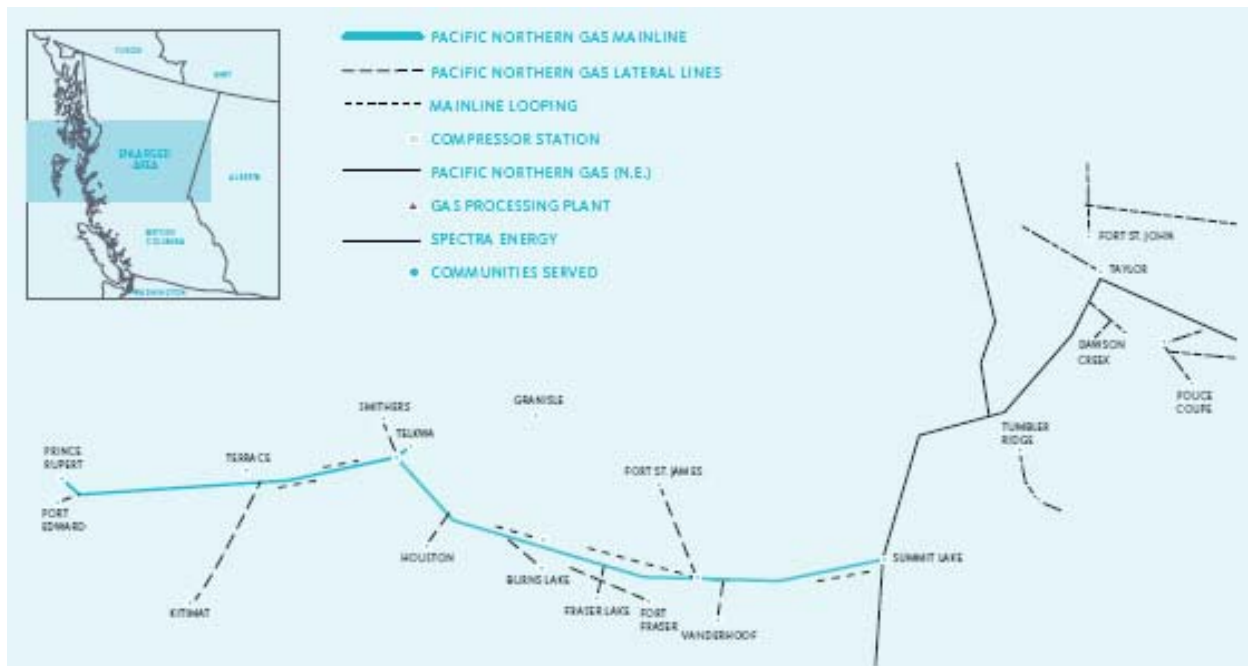
West Fraser has yet to provide PNG with the required six months cancellation notice and therefore PNG has yet to receive the termination payment. Until West Fraser provides termination notice, PNG expects West Fraser to continue to pay PNG the monthly demand charge due under the transportation agreement. PNG expects that the termination payment would be given the same regulatory treatment as the Methanex termination payment and would be amortized over the remaining life of the agreement. In addition, as was the case with the closure of the Methanex plant, lost future revenues from the West Fraser contract are expected to be recoverable through standard rate applications to the Commission. If this is the case, PNG’s anticipates limited impact on future earnings.

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 2009 the Company was delivering gas to 39,113 residential, commercial and industrial customers. The Company had three large industrial customers in 2009: West Fraser, Rio Tinto Alcan Inc. (“Rio Tinto Alcan”) and British Columbia Hydro and Power Authority (“BC Hydro”). These three customers accounted for 22.9 percent of total gas deliveries and 9.6 percent of the Company's operating margin during 2009.

The Company's combined rate base for 2009, as approved by the Commission, was approximately \$169 million.

Gas distributed by the Company to its residential and commercial customers and to certain industrial customers in 2009 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 2010.

If the transportation service agreement with Merrill Lynch comes into effect, with a target date between January 1, 2012 and January 1, 2013, PNG's Western pipeline system would be at full capacity utilization, requiring reactivation of these compressor stations. The cost to reactivate these facilities 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.

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, 2010, and Prince Rupert, where the agreement expires in 2015 and Fraser Lake, where the expiry date is indeterminate pending Commission approval of the agreement), and is renewable at the option of either party for a

further term of 21 years. PNG will be giving notices of renewal of the Port Edward agreement prior to the October 5, 2010 expiry date.

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 2011 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 83,700 in 2009.

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 $120 \times 10^3 \text{ m}^3$ 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 agreement with the City of Dawson Creek and the operating agreement with 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 58,000 in 2009.

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 12.1 PJ in 2009 compared with 12.5 PJ in 2008. Deliveries to large industrial sales and transportation customers decreased 15.2 percent from 2008 to 2009, primarily as a result of reduced deliveries to West Fraser which accounted for 66 percent of large industrial customer deliveries in 2009. These reduced deliveries related to the lower demand and lower prices for forest products in North America throughout 2009 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 31 percent also decreased by 6 percent in 2009 compared to 2008, mainly due to decreased deliveries to Alcan as it lowered its production of aluminum during the year.

Deliveries to small industrial customers increased slightly by 0.6 percent compared to 2008. This was mainly due to higher than anticipated consumption by a new customer in the Fort St. John service area, offset by lower deliveries to other small industrial customers, mainly in the forestry sector as many companies scheduled planned shutdowns during the year and reduced lumber production levels.

Deliveries to residential customers in 2009 increased by approximately 0.4 percent compared to 2008 mainly due to weather that was approximately 3.6 percent colder in the Northeast region in 2009 compared to 2008 while weather in the PNG West area was 2% warmer in 2009 compared to 2008. Deliveries to commercial customers increased in 2009 by approximately 2.5 percent from 2008 levels due partly to the colder weather, and some large commercial customer additions in 2009.

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>2009</u>	<u>2008</u>	<u>2007</u>
Deliveries (in terajoules):			
Residential	3 221	3 210	3 213
Commercial	3 081	3 007	2 904
Small industrial.....	3 066	3 049	3 234
Large industrial.....	2 777	3 276	3 859
Total energy delivered	<u>12 145</u>	<u>12 542</u>	<u>13 210</u>
Customers at Year End:			
Residential	33,910	33,862	33,943
Commercial	5,142	5,190	5,026
Small industrial.....	58	58	56
Large industrial.....	3	3	3
Total number of customers	<u>39,113</u>	<u>39,113</u>	<u>39,028</u>
Revenue (Dollars in thousands):			
Sales Revenue			
Residential	\$39,783	\$44,937	\$41,589
Commercial	29,600	31,974	28,373
Small industrial.....	3,830	4,486	4,327
Large industrial			
Rio Tinto Alcan.....	2,477	4,025	4,451
BC Hydro.....	—	—	—
Off system sales	14,839	32,508	36,083
Total sales revenue.....	<u>90,529</u>	<u>117,930</u>	<u>114,823</u>
Cost of gas	<u>(57,239)</u>	<u>(86,124)</u>	<u>(84,446)</u>
Operating margin from sales	<u>33,290</u>	<u>31,806</u>	<u>30,377</u>
Transportation Revenue			
Residential.....	—	—	—
Commercial.....	1,330	1,794	1,472
Small industrial	2,709	2,832	2,998
Large industrial			
West Fraser.....	2,114	2,273	2,018
Rio Tinto Alcan.....	980	906	832
BC Hydro	98	89	89
Off system sales	—	—	—
Total transportation revenue / operating margin from transportation.....	<u>7,231</u>	<u>7,894</u>	<u>7,409</u>

Other Revenue			
Methanex termination payment	5,466	6,592	6,752
Miscellaneous revenue	905	423	480
Total Other Revenue	<u>6,371</u>	<u>7,015</u>	<u>7,232</u>
Total operating margin	<u>46,892</u>	<u>46,715</u>	<u>45,018</u>

Large Industrial Customers

Overview

The Company currently has transportation service agreements with West Fraser and Rio Tinto Alcan. The Company 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 Methanex covering the period November 1, 2002 through October 31, 2009; however Methanex served notice to terminate its agreement with the Company effective February 28, 2006, as discussed below.

West Fraser

Under the terms of its agreement with West Fraser, the Company provides firm gas transportation service to West Fraser's linerboard and kraft paper mill in Kitimat, British Columbia. The agreement specifies a daily contract demand volume of 170.0 10³m³ (6.0 MMcf). A unit demand toll of \$0.85 per GJ applied for the first five years of the term of the agreement, ending on December 31, 2008. For the second five years of the term, commencing January 1, 2009, the toll was adjusted by 50 percent of the change in the British Columbia Consumer Price Index over the five year period ending December 31, 2008, to \$0.8908/GJ. West Fraser pays a minimum monthly demand charge equal to the unit demand toll times the contract demand times the number of days in the month regardless of the level of actual deliveries. The contract also provides for interruptible transportation of volumes in excess of the contract demand at a toll of 1.15 times the firm toll. In addition, West Fraser supplies a portion of the Company's internal gas requirements equal to 2 percent of deliveries to West Fraser (reduced from 4 percent prior to January 2007). During 2009, deliveries to West Fraser accounted for approximately 15.1 percent of the Company's total gas deliveries and 2.0 percent of revenues.

The agreement with West Fraser expires as of December 31, 2013, but West Fraser may terminate its obligations under the agreement with six months' notice and payment of a buy-out payment to the Company on the effective date of the termination. The buy-out payment was set at \$10,500,000 as of January 1, 2005 and reduces monthly to \$1,775,000 as of January 1, 2013. On October 28, 2009, West Fraser announced the permanent closure of its Eurocan paper mill in Kitimat, BC by January 31, 2010.

West Fraser has yet to provide PNG with the required six months cancellation notice and therefore PNG has yet to receive the termination payment. Until West Fraser provides termination notice, PNG expects West Fraser to continue to pay PNG the monthly demand charges due under the transportation agreement. PNG expects that the termination payment would be given the same regulatory treatment as the Methanex termination payment and would be amortized over the remaining life of the agreement. In addition, as was the case with the closure of the Methanex plant, lost future revenues from the West Fraser contract are expected to

be recoverable through standard rate applications to the Commission. If this is the case, PNG's anticipates limited impact on future earnings.

Rio Tinto Alcan

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 2009, deliveries to Rio Tinto Alcan accounted for 7.6 percent of the Company's total gas deliveries and 3.3 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 has slowed the pace of work on the modernization project.

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 totalled 14 TJ in 2009, compared to 7 TJ in 2008. 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.

Methanex

Transportation service to Methanex in 2005 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 has sought 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 to 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 2009, approximately 40 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 77 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 33 percent of that system's requirements in 2009. In Dawson Creek, approximately 6 percent of the required supply in 2009 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 2009, 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 no change to the ending number of customers in 2009 as the Northeast system service area experienced a net gain of 227 customers and the Western system service area experienced a net loss of the equivalent number of customers.

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 in the Western system service area. The Company does expect to add approximately 250 new customers in 2010 in the community of Tomslake, B.C., in the Dawson Creek division service area as it finalizes the new gas distribution system in this rural area. The Company expects to see some customer losses in Kitimat and surrounding areas due to the closure of West Fraser's Kitimat paper mill. It is too early to predict with any degree of certainty what the customer losses may total.

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 prudency 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 Commission issued a decision in December 2009 establishing the benchmark ROE, without reference to the formula, at 9.50 percent effective July 1, 2009 and for 2010. 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 recovery 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 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.

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

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

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

transmission facilities deactivated in 2006 as a result of the loss of load following the closure of the Methanex methanol/ammonia plant.

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

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

The Commission established a regulatory timetable for review of the CAP/ROE Application on January 19, 2010. The timetable provides an opportunity for the parties to attempt a negotiated settlement process following the filing of responses by the Company to information requests from Commission staff and intervenors. If the negotiated settlement process is not successful or does not take place, then the Commission will render a decision following the receipt of written argument from the Company and registered intervenors. In this event, the Commission's decision would be expected in June 2010. While the Company is confident in the merits of its CAP/ROE Application as filed and amended, it can give no assurances that the applied for capital structure and equity risk premium increases from current levels will be approved by the Commission.

2009 Revenue Requirements Applications

The Company and its customers negotiated settlements of the 2009 revenue requirements applications for each of the Company's divisions. The settlements were approved by the Commission on April 23, 2009. The agreed to Western system delivery charge increase for a typical residential customer was approximately 5 percent compared to rates effective prior to January 1, 2009. This increase was been more than offset by gas commodity charge decreases throughout 2009. The Fort St. John/Dawson Creek division residential delivery rates declined an average of 3.4 percent primarily due to lower debt interest costs. The Tumbler Ridge division average residential delivery rate also declined by 6.5 percent. In all divisions, the agreed to delivery rates were less than the interim rates and therefore customers received refunds on gas deliveries from January 1 to April 30, 2009.

2010 Revenue Requirements Applications

In early October 2009, the Company filed its 2010 revenue requirements applications for all divisions. The applications sought approval to increase rates on an interim basis effective January 1, 2010 pending the Commission's review of the CAP/ROE Application. The Western system is projecting a 2010 revenue deficiency of approximately \$7.7 million of which \$5.5 million is due to the Methanex contract termination payment credit amortization ending in October 2009.

PNG(N.E.)'s Fort St. John/Dawson Creek division has a forecast revenue deficiency of close to \$0.9 million while the Tumbler Ridge division 2010 revenue deficiency is approximately \$0.1 million. The applied for delivery charge increases compared to October 2009 delivery rates for an average residential customer in each service area are 28.5 percent for the Western system (\$213 per year), 8.9 percent for the Fort St. John/Dawson Creek division (\$32 per year) and 7.8 percent for the Tumbler Ridge division (\$37 per year). However, compared to rates effective January 2009, when gas supply recovery rates were much higher than current rates, the annual bill increase for a typical residential customer in the Western system is only \$66 per year. The Fort St. John/Dawson Creek and Tumbler Ridge average residential customer annual bills in 2010 are projected to be lower by \$240 and \$213, respectively, compared to annual bills based on January 2009 rates.

On October 30, 2009 the Commission approved interim rates effective January 1, 2010 based on currently approved 2009 common equity thicknesses and ROE's for each division and not the higher figures set forth in the CAP/ROE Application and which were used to calculate forecast 2010 revenue requirements. A negotiated settlement process is being conducted with respect to the 2010 revenue requirements applications on the understanding that gas delivery rates will remain interim effective January 1, 2010 until completion of the CAP/ROE Application review process.

The gas supply commodity charge component of rates declined throughout 2009 compared to the rates effective January 1, 2009. The Commission reviews the gas supply commodity charges on a quarterly basis. The fourth quarter 2009 report resulted in gas supply commodity charges effective October 1, 2009 remaining unchanged in all divisions effective January 1, 2010. The next potential change to the gas supply charge in rates will be April 1, 2010.

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, 2009 and as applied for under the Company's 2010 revenue requirement applications and CAP/ROE application:

	Years ended December 31			
	2010*	2009	2008	2007
Western system:				
Rate base.....	\$129,949*	\$131,358	\$132,938	\$131,628
Common equity component.....	47.50%*	40.0%	40.0%	40.0%
Allowed return on common equity	10.25%*	9.63%	9.27%	9.02%
Fort St. John/ Dawson Creek division:				
Rate base.....	\$38,560*	\$36,363	\$33,486	\$31,966
Common equity component.....	42.5%*	36.0%	36.0%	36.0%
Allowed return on common equity	10.25%*	9.38%	9.02%	8.77%
Tumbler Ridge division:				
Rate base.....	\$1,715*	\$1,565	\$1,465	\$1,360
Common equity component.....	42.5%*	36.0%	36.0%	36.0%
Allowed return on common equity	10.25%*	9.63%	9.27%	9.02%

*estimate, subject to Commission approval

Credit Facilities

At December 31, 2009, the Company's credit facilities included a \$25 million operating line, a \$20 million 5-year revolving term facility maturing on August 3, 2012 and a \$15 million risk management facility. The Company's operating line was increased by \$5 million from \$20 million to \$25 million on July 8, 2009 and its term renewed for 18 months. The operating line, which now expires January 7, 2011, is collateralized by a charge on the Company's accounts receivable and inventories. Draws on the operating line may be made by way of prime rate advances at the lender's prime rate plus 1.5 percent or by the issuance of the lender's Bankers' Acceptances which are subject to a credit spread of 3.0 percent. The operating line is also subject to borrowing base requirements and a financial covenant requiring the Company's debt leverage not to exceed 65 percent, or approximately the same level currently approved by the Commission for rate making purposes.

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

The Company's risk management facility allows it to hedge natural gas purchases in accordance with its annual gas contracting and gas price risk management plan and to enter into interest rate

hedging transactions to a total maximum exposure of \$15 million, with exposure calculated by the facility provider using its standard methodology. The risk management facility is secured by the pledge of a \$20 million debenture issued by the Company and contains a financial covenant requiring the Company's debt leverage not to exceed 65 percent.

Subsequent to December 31, 2009, the Company added a second risk management facility with another provider. This facility, arranged in January 2010, has two financial covenants, one which requires the Company's debt leverage not to exceed 65 percent and the second which requires the Company to maintain an interest coverage of 1.5 times or higher using earnings before interest, income taxes and expenditures on the KSL Project to a maximum of \$10 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. This risk management facility also allows the Company to hedge natural gas purchases in accordance with its annual gas contracting and gas supply price management plan and to enter into interest rate hedging transactions to the extent of a total maximum exposure of \$15 million, where exposure is calculated by the facility provider using its standard methodology. The new risk management facility is also secured by the pledge of a \$20 million debenture issued by the Company.

On February 2, 2010 the 5-year revolving term facility was amended to increase the credit available under the facility to \$35 million and extend the maturity date to January 30, 2015. Interest rates under the facility were increased such that draws under the facility are made by way of advances at the prime rate plus 2.0 percent or by way of Bankers' Acceptance equivalent loans at CDOR plus 3.075 percent. The financial covenants under the facility remain as described in the previous paragraph. The Commission's approval of the amended facility was provided on the basis that draws on the facility can only be utilized for utility purposes. The Company does not expect this condition to materially impact its ability to fund its strategic initiatives, including the KSL project and acquisition or development of independent hydro power facilities, as it can utilize the common equity on its balance sheet that is in excess of the common equity that the Commission allows to underpin the Company's utility assets.

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 and in the construction of new facilities. 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 KSL Project, 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.

Green house gas 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. Subsequent to the ratification of the Kyoto Protocol in December, 2002, the pace of regulatory developments that address the problems of stabilizing and then reducing anthropogenic carbon emissions into the atmosphere has been increasing. Several emissions reduction schemes are now in operation including the European Emissions Trading System (2005), the Regional Greenhouse Gas Initiative (2009), and the Alberta-based Offset Credit System (2007). 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 begun the development of regulations supporting the implementation of a cap-and-trade system aligned with the principles agreed to by the WCI partners. B.C. is in the process of finalizing its reporting regulations that harmonize with the WCI draft requirements and support the planned for cap-and-trade program. The Mandatory Reporting of Greenhouse Gas Emissions Regulation (GHG Reporting 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 proposed regulation, facilities emitting more than 10,000 tonnes CO_{2e} per year will be required to report their annual GHG emissions beginning with the 2010 calendar year, with the first report due April 1st, 2011. 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 2009 inspection activity involved 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 2010 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. The Company believes its operations are in compliance with applicable environmental laws, rules regulations and guidelines in all material respects.

Employees

At December 31, 2009, the Company had 102 employees, comprised of 76 unionized and 26 non-unionized employees. All unionized employees are members of the International Brotherhood of Electrical Workers (the "Union"). The Company's collective agreement with the Union expired on October 31, 2007 and was successfully renegotiated with a new expiry 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.

KSL Project

The Company continues to pursue a project to loop its mainline transmission system from Kitimat to Summit Lake (the "KSL Project") through its 50 percent ownership of Pacific Trail Pipelines Limited Partnership ("PTP"). Upon completion of the KSL Project, and subject to regulatory and shareholder approvals, the Company's existing mainline transmission system will be transferred to PTP and integrated with the KSL Project facilities. The Company will continue to own and operate its existing gas distribution systems, including its Customer Care Centre in Terrace. Construction of the KSL Project facilities is scheduled to commence in 2012 for completion in 2014.

Conditions to construction include the securing of contracts for use of PTP's transportation capacity, financing for construction of the KSL Project, and additional regulatory approvals for the KSL Project such as a Certificate of Public Convenience and Necessity ("CPCN") from the Commission and other permits from the B.C. Oil and Gas Commission. The Company will be working to finalize transportation reservation agreements for the KSL Project by the second quarter of 2010 at which point it would prepare and file its CPCN application with the Commission. PTP can give no assurances that such agreements will be signed or other conditions will be satisfied or that construction of the KSL Project by PTP will proceed. If construction of the KSL Project does not proceed, and without development of other strategic initiatives, the Company will remain reliant on its existing customer base and assets. The risks associated with the existing customer base and assets are described in the other risk factors in

this section, particularly those found under the headings Commodity Price and Supply Risks, Usage Risks and Potential for Termination of Large Industrial Contracts.

Following environmental certification, expenditures on the KSL Project have been minimized and will continue to be expensed until suitable commercial arrangements for firm gas transportation services by PTP are in place at which point development costs of the project would be capitalized. Assuming, commercial arrangements for the KSL Project are completed by the second quarter of 2010, the Company expects its 50 percent share of KSL Project development costs in 2010 will total approximately \$5.5 million, of which approximately 90 percent would be capitalized. These costs would primarily relate to additional engineering and technical studies for the KSL Project pipeline. In addition, management has estimated that the construction of the KSL Project will cost approximately \$1.2 billion based on estimates made in 2006. Development and construction costs could be higher than expected.

Liquidity, Cash Flow and Capital Availability Risks

The Company has several credit facilities, including a \$25 million operating line, a \$20 million 5-year term revolving credit facility and a \$15 million risk management facility at the end of 2009. The operating line, which is available for working capital requirements, is subject to borrowing base requirements and 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, 2009 the Company's debt to capitalization ratio was under 50 percent. See "Management's Discussion and Analysis – Capital Resources – Short Term Debt". At December 31, 2009 the borrowing base was approximately \$13.8 million and the Company had utilized \$8.3 million of the operating line by way of overdraft on the operating line and outstanding letters of credit in the amount of \$5.7 million issued under the line to secure certain gas purchase obligations as well as the Company's obligations under its unfunded supplemental retirement plan. 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 \$15 million risk management facility to enter into financial derivative contracts which help mitigate the volatility of its gas purchase costs.

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 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. The risk management facilities allow the Company to hedge natural gas purchases in accordance with its annual gas contracting and gas supply price risk management plan and to enter into interest rate hedging transactions to the extent of a total maximum exposure of \$15 million under each of the facilities, where exposure is calculated by the facility provider using its standard methodology.

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 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.

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 2009 was approximately 18 percent lower than in 2008 and 17 percent lower than in 2007. 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 2009, approximately 22.8 percent of energy deliveries were made to the Company's two largest industrial customers, Rio Tinto Alcan and West Fraser, representing approximately 9.4 percent of the consolidated operating margin of the Company.

Under the terms of its transportation agreement, West Fraser pays PNG an annual demand charge of approximately of \$2.1 million and is entitled to cancel its obligations by providing PNG with a termination payment that would recover almost 80 percent of the lost revenues under the remaining term of the agreement. West Fraser has ceased operations at its Kitimat mill and has not provided a contract termination notice to PNG which would trigger the obligation to make the termination payment. In 2009, deliveries to West Fraser accounted for 15.1 percent of the Company's total gas deliveries and 2.0 percent of revenues.

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 2009, deliveries to Rio Tinto Alcan accounted for 7.6 percent of the Company's total gas deliveries and 3.3 percent of revenues. 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. 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 strength of the Canadian dollar in 2009. 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 in 2003 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 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.

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. The most recently filed valuation was prepared on December 31, 2006. The next valuation is required to be prepared as at December 31, 2009 and will determine the contributions required from 2010 onwards. The Company's actuaries have been engaged to prepare this valuation. If the plan experiences negative returns or fails to recover market it may result in large contribution requirements beyond 2009.

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

Effective January 1, 2011, the Company is required to report under IFRS as issued by the International Accounting Standards Board with 2010 comparatives. IFRS will require increased financial statement disclosure compared to Canadian GAAP and accounting policy differences between Canadian GAAP and IFRS are being addressed. The Company is currently assessing the impact that conversion to IFRS will have on its future financial reporting. In the event that regulated assets and liabilities are not permissible under IFRS, this could result in increased volatility in the Company's consolidated earnings and balance sheet from that reported under Canadian GAAP.

DIVIDENDS

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

	<u>2009</u>	<u>2008</u>	<u>2007</u>
Dividends per share			
- common	\$0.96	\$0.88	\$0.80
- preferred	\$1.69	\$1.69	\$1.69

On March 4, 2009 the Board of Directors approved an increase in the quarterly dividend to \$0.23 per Common Share and on July 30, 2009 the Board of Directors approved a further increase in the quarterly dividend to \$0.25 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 ¾ percent cumulative redeemable preferred shares with a par value of \$25 each (the "Preferred Shares"). There are 3,584,564 Common Shares, no Junior Preferred Shares and 200,000 Preferred Shares issued and outstanding at February 8, 2010.

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 ¾ Percent Cumulative Redeemable Preferred Shares

The Preferred Shares are entitled to the payment of fixed cumulative preferential cash dividends at the rate of 6 ¾ 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

Through August 10, 2009, the Company's preferred shares were rated Pfd-3(low) by Dominion Bond Rating Service ("DBRS") and the Company's secured debentures were rated BBB(low), both with a Negative trend. On August 11, 2009, DBRS confirmed the Company's secured debt and preferred share ratings at BBB(low) and Pfd-3(low) respectively and changed the trends to Stable from Negative.

In its ratings report dated February 2, 2009, DBRS noted the following key challenges for PNG in arriving at the ratings for the Company's long term debt and preferred shares:

- Future outcome of BCUC's decision on rates when Methanex amortization ends in 2009.
- Economic conditions in PNG's Western system service area remains challenging.
- Competitiveness of natural gas versus alternative fuel sources.
- Low interest rate environment negatively impacts earnings through approved return on equity.
- Deemed equity component viewed as low.

In its press release date August 11, 2009, DBRS noted:

"The trend has been changed based on our review of the BCUC decision and PNG's second quarter financial results, as well as our expectation that PNG will maintain a capital structure similar to its current profile".

The recently negotiated settlement for PNG-West's 2009 rates (as approved by the BCUC) included a rate increase that incorporates the impact of the end of the Methanex termination payment amortization in October 2009. While the rate increase only reflects two months of the year (November and December), the trend change incorporates the assumption that 2010 rates will be increased to substantially account for the remaining impact of the end of the Methanex termination payment amortization."

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 negative 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, 2009 for the common shares and the 6 3/4 percent preferred shares:

Common shares:	High	Low	Volume
January	\$14.11	\$ 13.00	20,855
February	14.00	11.71	50,259
March	13.00	11.40	152,677
April	13.01	11.93	151,628
May	15.49	12.99	68,478
June	16.35	14.95	56,139
July	17.20	15.35	158,761
August	18.65	16.90	141,845
September	19.00	18.00	91,690
October	19.35	18.50	55,952
November	19.35	18.50	66,346
December	19.40	18.70	48,364

Preferred shares:	High	Low	Volume
January	\$24.50	\$24.00	2,765
February	25.00	24.05	1,400
March	24.80	24.00	2,800
April	25.00	24.50	1,600
May	24.95	24.00	1,900
June	24.75	24.30	1,700
July	24.88	24.27	1,835
August	25.50	24.55	1,100
September	26.00	25.50	1,200
October	25.50	25.50	700
November	27.50	25.25	1,930
December	26.26	26.00	3,250

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 February 8, 2010	Number of DSU's at February 8, 2010	Purchase Value of Common Shares and DSU's ⁽⁶⁾
Robert F. Chase: Chair of the Board; President and Chief Executive Officer of New West Energy Services Inc. (an oil and gas services company); resident in British Columbia, Canada; a director of the Company since April 26, 1995 ^{1,4,5}	2,000	7,490.59	\$164,245
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}	3,300	1,520.09	\$81,667
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	81,566	--	Note 7
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	3,045.60	\$50,253
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}	5,000 Note 8	2,622.91	\$117,612
David G. Unruh: Corporate Director; resident in British Columbia, Canada; a director of the Company since March 21, 2002 ^{3,4}	Nil	4,108.29	\$69,370
Arthur H. Willms: Corporate Director; resident in British Columbia, Canada; a director of the Company since April 28, 1983 ^{1,5}	Nil	3,191.27	\$52,962
Janet P. Woodruff: Interim President, BC Transmission Corporation (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	2,566.48	\$42,019

(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 Corporate Governance Committee

(5) Member of the Human Resources and Compensation Committee

(6) 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 \$17,500) 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.

(7) 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 February 5, 2010 of \$21.05, these shares had a market value of \$1,716,964.

(8) 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 February 8, 2010
<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	81,566
<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; 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 is currently and 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, 2009 to December 31, 2009. All members of this Committee are independent as defined under Multilateral Instrument 52-110 “Audit Committees”.

Relevant Education and Experience

Each member of the Audit Committee 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 of BC Transmission Corporation and now Interim President of BC Transmission Corporation. 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, the Investment Committee and the Audit Committee of the Insurance Corporation of British Columbia. 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.

Reliance on Certain Exemptions

Since January 1, 2009, 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, 2009 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	Audited-Related Fees⁽¹⁾	Tax Fees⁽²⁾	All Other Fees
2009	\$166,700	\$67,605		
2008	\$159,000	\$77,910	---	---

(1) Audit-related fees pertain to quarterly reviews in 2008 and 2009, consultation on accounting matters, audit of savings plans, 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 2007, 2008 or 2009.

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.

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 2010 Annual Meeting of Shareholders. Additional financial information is provided in the Company's consolidated financial statements for the year ended December 31, 2009. Management's Discussion and Analysis for the year ended December 31, 2009 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:

- iv) 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;
- v) the services were not recognized by the Company at the time of the engagement to be non-audit services; and
- vi) 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 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.

Revised: October, 2009