



PACIFIC NORTHERN GAS LTD.

**ANNUAL
INFORMATION FORM**

For the 12 month period ended December 31, 2007

March 13, 2008

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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.

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

This annual information form includes forward-looking statements. Forward-looking statements relate to, among other things, anticipated financial performance, business prospects, strategies, regulatory developments, new services, market forces, commitments and technological developments. 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 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
- 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; and the ability of the Company to attract and retain quality employees. 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.

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 utilities are separate stand-alone systems and both are regulated by the Commission.

On August 30, 2005, one of the Company’s large industrial customers, Methanex Corporation (“Methanex”) gave notice of termination of its transportation agreement with the Company. Under 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. 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, to be amortized into income over the period March 1, 2006 to October 31, 2009, the original date of expiry of the transportation agreement.

In 2005 the Company commenced preliminary study and investigation of a project to loop its mainline transmission system from Kitimat to Summit Lake (the “KSL Project”). The KSL Project is being proposed to provide gas transportation services for up to 1.0 billion cubic feet

per day from the proposed Kitimat LNG Inc. liquefied natural gas (“LNG”) receiving and regasification terminal (the “Terminal”) to be located on the Douglas Channel approximately 15 kilometers southwest of Kitimat. The gas will be transported to the Company’s existing interconnection with the system owned by Westcoast Energy Inc., a Spectra Energy company (“Spectra Energy”, formerly Duke Energy). The KSL Project entails the construction of approximately 470 kilometers of a 36 inch diameter pipeline and associated compression facilities at a cost of \$1.2 billion based on estimates made in 2006. The route for the KSL Project is being determined through technical field studies and consultation with First Nations, the public and regulatory authorities. The Company’s existing right-of-way will be used where appropriate. In 2006, Kitimat LNG Inc., a subsidiary of Galveston LNG Inc., a private company based in Calgary, Alberta received a Project Approval Certificate from the British Columbia Environmental Assessment Office (“BCEAO”) as well as approval from the Canadian Environmental Assessment Agency (“CEAA”) for the construction and operation of the Terminal.

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. In addition, PTP and Kitimat LNG executed a Precedent Agreement to coordinate the process of obtaining authorizations for the KSL Project with the development of the Terminal. The agreement outlines, among other things, the key economic arrangements between PTP and Kitimat LNG, as well as the targeted timeline and key milestones for construction of the KSL Project and the Terminal. 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.

In 2008 PTP will continue to pursue environmental certification by both the BCEAO and CEAA of the KSL Project. PTP’s Environmental Assessment Certificate application for the KSL Project is under review and the related assessment report is scheduled to be completed in April 2008. On this basis, the Company expects that the BCEAO and CEAA approvals will be granted in the second and third quarters of 2008, respectively. Subject to a number of other conditions, including the securing of LNG supply by Kitimat LNG Inc., financing of the Terminal and KSL Project facilities and obtaining other regulatory approvals for the KSL Project, construction of the KSL Project by PTP is expected to commence in 2009 for completion in 2011 when the Terminal is expected to begin operation. The Company can give no assurance that construction of the Terminal by Kitimat LNG Inc. or construction of the KSL Project by PTP will proceed.

On October 18, 2005 the Company engaged two international banks as co-arrangers for the project financing of the proposed KSL Project. These banks were also concurrently engaged by Kitimat LNG Inc. as co-arrangers for the project financing of the proposed Terminal.

The cumulative cost associated with the KSL Project incurred by the Company to the end of 2006 was \$2.8 million (\$1.6 million after income taxes). A further \$2.1 million (\$1.4 million after income taxes) was incurred in 2007. The Company is currently expensing all KSL Project development expenditures until suitable commercial arrangements for firm gas transportation

services by PTP are in place. Management expects that the Company's share of development expenditures on the KSL Project in 2008 will be approximately \$0.6 million (\$0.4 million after income taxes). Following environmental certification, expenditures on the KSL Project will be minimized until suitable commercial arrangements for firm gas transportation services by PTP are in place at which point development costs of the project would commence being capitalized.

On December 17, 2004, the Company filed an application with the Commission seeking the approvals required pursuant to the Utilities Commission Act to transfer the ownership of the Company from the current common shareholders to an income trust called the "PNG Income Trust". By decision dated September 9, 2005 and modified on October 28, 2005, the Commission granted conditional approval of the Company's December 2004 application to recapitalize under an income trust ownership structure.

In connection with the Company's announcement on July 17, 2006 that it entered into a partnership arrangement with Galveston LNG Inc. to jointly develop the KSL Project, the Company indicated that conversion to an income trust would not be pursued while the KSL Project continues under development. In addition, in June, 2007 the federal government enacted legislation relating to proposals announced on October 31, 2006 to disallow as a tax deduction the distributions made by most income trusts. As a result, the Company will not pursue conversion to an income trust.

On April 12, 2005, all of the common shares of the Company owned by Tricor Acquisition (STP) Inc., a subsidiary of Tricor Pacific Capital, Inc. ("Tricor"), representing 37 percent of the outstanding common shares of the Company, were sold through a secondary public offering at a price of \$19.40 per common share, for total gross proceeds of approximately \$26 million.

Trends and Competition

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 result of relatively higher gas supply costs over the past few years and increased gas delivery tolls resulting from the lower utilization of the Western system pipeline, the Company keeps focused on the competitiveness of natural gas retail rates relative to alternative heating sources in the Western system service area, primarily electricity. The Western system residential rates have been slightly higher than comparable electricity rates over the last few years while commercial gas rates have been lower than electricity rates. Both residential and commercial gas rates remain lower than electricity rates in the Northeast system service area.

The Province of British Columbia's 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 are expected to result in higher electricity rates with a corresponding impact on

the competitiveness of gas relative to electricity. More specifically, electricity rate increases effective April 1, 2008 are expected to be approximately 5 percent and an additional 15 percent on a cumulative basis over the following two BC Hydro fiscal years commencing April 1, 2009 and 2010. In addition, on February 26, 2008 BC Hydro filed an application with the Commission to implement an inclining rate structure for residential customers to encourage electricity conservation. The application requests approval for a two-tiered pricing structure where a higher electricity price would apply to consumption in excess of a base amount. The Company believes that the new pricing structure will help discourage its residential customers from using electricity in substitution for space and water heating with natural gas.

The Province of B.C. announced in its budget on February 19, 2008 a carbon tax on fossil fuel consumption. The proposed carbon tax on natural gas would be just under \$0.50 per GJ effective July 1, 2008, rising to just under \$1.50 per GJ effective July 1, 2012. The Company's gas rates are expected to maintain their relative competitiveness with electricity rates as the proposed electricity rate increases are higher than the proposed carbon tax on natural gas.

Prior to 2007, high natural gas prices and weak economic conditions faced by the Company's customer base in the Western system service area had reduced the quantity of gas sold and delivered to the Company's customers in that area. Currently, natural gas prices are more competitive with other heating sources compared to recent years and the economy in the Western system service area is beginning to show improvement, as discussed below. The economy in the Northeast system service area continues to grow as a result of activity in the oil and gas exploration sector, which is reflected in customer additions in that area.

The Company, like other gas utilities in Canada, has experienced reductions in average gas consumption per residential and small commercial customer over the last several years. However, in 2007, the average use per residential customer was slightly higher compared to 2006 in both the Western and Northeast systems. Similarly, the use per small commercial customer was slightly higher in 2007 than 2006 in the Northeast system. The small commercial use per account was somewhat lower in 2007 compared to 2006 in the Western system. The Company believes that only a small portion of the reduction in average gas consumption has resulted from substitution of other fuels for natural gas, with only a limited amount of load having switched to electricity at this time. The main reason for the reduction in average gas consumption is considered to be the result of conservation measures undertaken by consumers in response to higher natural gas prices and poor economic conditions experienced over this period in the Western system service area together with the use of higher efficiency gas appliances. Gas consumption by small industrial customers in the Western system service area has also declined through conservation and substitution of wood waste for natural gas.

In addition to the effect of conservation and substitution of energy sources, the Company has experienced a net loss in the number of customers in the Western system which has been offset by the addition of customers to the Northeast system with the result that the Company's overall number of customers over 2005 to 2007 has increased slightly. The poor economic conditions in the Western system service area are believed to be responsible for the majority of the decline in the number of residential customers. Certain small industrial customers also closed down, contributing to the reduced economic activity in the Western system service area and the decline in gas consumption in the small industrial sector.

These recent trends are not necessarily indicative of future trends. Management of the Company expects there to be a limit to the conservation measures that can be undertaken by residential, commercial and industrial customers. Further, there are a number of initiatives and prospects in the Western system service area that could have a positive impact on the economic conditions in this service area, including:

- completion of Phase 2 of a new container handling facility at the Port of Prince Rupert;
- construction of a proposed US\$2 billion modernization of the aluminum smelter owned by Alcan Smelters and Chemicals Ltd. (operating as Rio Tinto Alcan) in Kitimat;
- construction of the Kitimat LNG Terminal and KSL Project pipeline; and
- construction of oil and/or condensate pipelines from Alberta to tidewater at Kitimat.

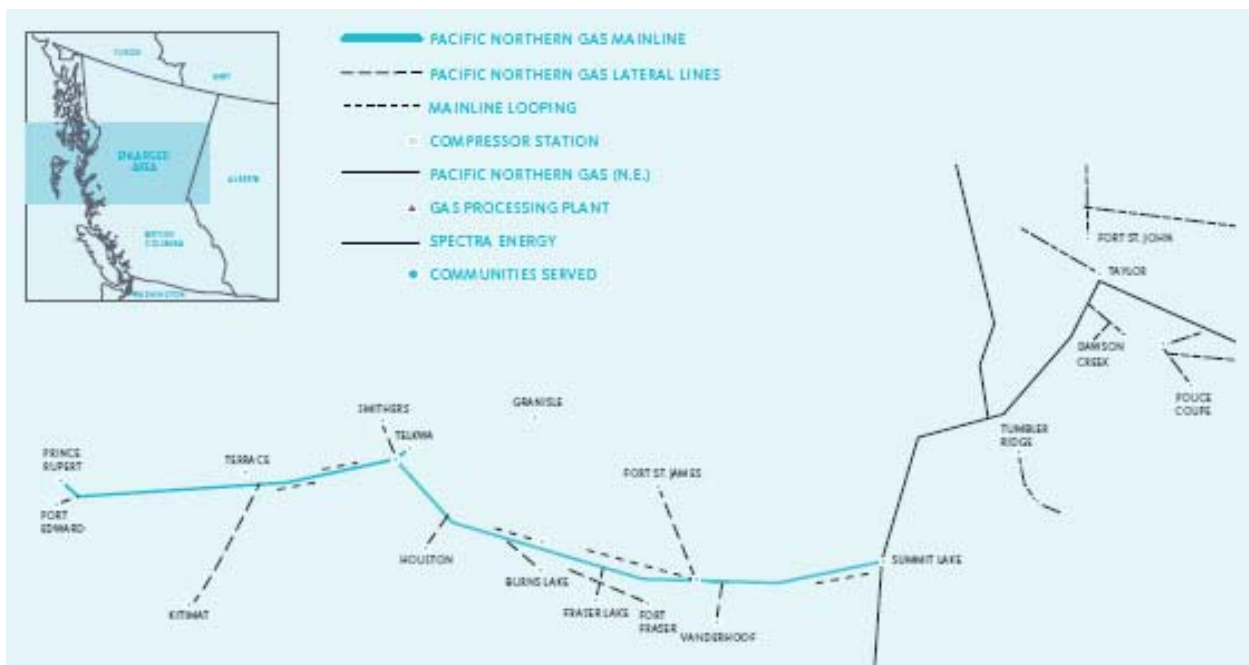
Management can give no assurances that these initiatives will proceed to completion.

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 2007 the Company was delivering gas to 39,573 residential, commercial and industrial customers. The Company had three large industrial customers in 2007: West Fraser Mills Ltd. ("West Fraser"), Alcan Smelters and Chemicals Ltd. ("Rio Tinto Alcan") and British Columbia Hydro and Power Authority ("BC Hydro"). These three customers accounted for 29 percent of total gas deliveries and 9 percent of the Company's operating margin during 2007.

The Company's combined rate base for 2007, as approved by the Commission, was approximately \$165 million.

Gas distributed by the Company to its residential and commercial customers and to certain industrial customers in 2007 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 the majority of its net income in the first and fourth quarters of its fiscal year and generally incurs 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 kilometers 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 kilometers of lateral transmission pipelines extending into the various communities served by the Company, the most significant being dual lines extending approximately 57 kilometers 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 $3\ 260\ 10^3\text{m}^3$ (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 2008.

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 kilometers 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 in 2010, and Prince Rupert, where the agreement expires in 2015), and is renewable at the option of either party for a further term of 21 years.

The Company also has operating agreements with the municipalities of Fort St. James and Telkwa 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 2009 and 2011, 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.

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 a total population of approximately 75,000 at December 31, 2007.

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 kilometers of transmission lines, 1,490 kilometers 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 at December 31, 2007.

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 13.2 PJ in 2007 compared with 12.4 PJ in 2006. Deliveries to large industrial sales and transportation customers increased 29.5 percent from 2006 to 2007, primarily as a result of increased deliveries to West Fraser which accounted for 69 percent of large industrial customer deliveries in 2007. However, deliveries to other large industrial

customers which accounted for the remaining 31 percent also increased by 20 percent in 2007 compared to 2006, mainly due to increased deliveries to BC Hydro for electric power generation following damage to their transmission line serving Prince Rupert.

Deliveries to small industrial customers declined in 2007 compared to 2006 primarily in the forestry sector. Low lumber prices and the high Canadian dollar negatively impacted lumber production levels. Two sawmills in the Western system shut down operations pending recovery of lumber markets while another cut back production levels.

Deliveries to residential customers increased in 2007 by approximately 4.8 percent from 2006 levels corresponding with weather being approximately 5 percent colder in 2007 compared to 2006. Deliveries to commercial customers increased in 2007 by approximately 1.5 percent from 2006 levels. Commercial transportation service deliveries increased from 2006 to 2007 primarily due to several commercial sales customers converting to transportation service in the latter part of 2006 and during 2007. Given these were conversions by existing sales customers, the increase in commercial transportation service deliveries resulted in a decrease in total operating revenues, however operating margin was relatively unaffected by the conversions.

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>2007</u>	<u>2006</u>	<u>2005</u>
Deliveries (in terajoules):			
Residential	3 213	3 066	3 135
Commercial	2 904	2 863	2 720
Small industrial.....	3 234	3 484	3 576
Large industrial.....	3 859	2 982	23 413
Total energy delivered	<u>13 210</u>	<u>12 395</u>	<u>32 844</u>
Customers at Year End:			
Residential	34,394	34,302	34,189
Commercial	5,121	5,156	5,047
Small industrial.....	55	50	55
Large industrial.....	3	3	4
Total number of customers	<u>39,573</u>	<u>39,511</u>	<u>39,295</u>
Revenue (Dollars in thousands):			
Sales Revenue			
Residential	\$41,589	\$44,919	\$42,354
Commercial	28,373	34,241	31,546
Small industrial.....	4,327	7,152	5,599
Large industrial			
Rio Tinto Alcan.....	4,451	5,087	5,370
BC Hydro.....	—	—	—
Off system sales	36,083	32,713	56,159
Total sales revenue.....	<u>114,823</u>	<u>124,112</u>	<u>141,028</u>
Cost of sales.....	(84,446)	(91,118)	(111,287)
Operating margin from sales	<u>30,377</u>	<u>32,994</u>	<u>29,741</u>
Transportation Revenue			
Residential.....	—	—	—
Commercial	1,472	630	217
Small industrial	2,998	3,308	3,188
Large industrial			
Methanex	—	1,822	12,182
West Fraser.....	2,018	2,017	2,016
Rio Tinto Alcan.....	832	842	735
BC Hydro	89	86	73
Off system sales	—	—	—
Total transportation revenue / operating margin from transportation.....	<u>7,409</u>	<u>8,705</u>	<u>18,411</u>
Other Revenue			
Methanex termination payment	6,752	5,552	—
Miscellaneous revenue	480	479	511
Total Other Revenue	<u>7,232</u>	<u>6,031</u>	<u>511</u>
Total operating margin	<u>45,018</u>	<u>\$47,730</u>	<u>\$48,663</u>

Note:

References to “operating margin” are to operating revenues less cost of sales. 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 activity.

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 (6.8 MMcf). A unit demand toll of \$0.85 per GJ applies for the first five years of the term of the agreement, ending on December 31, 2008. For the second five years of the term, the toll is \$0.85 per GJ adjusted by 50 percent of the change in the British Columbia Consumer Price Index over the five year period ending December 31, 2008. 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 2007, deliveries to West Fraser accounted for approximately 20.1 percent of the Company's total gas deliveries and 1.6 percent of operating revenues.

The agreement with West Fraser expires in December 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. Moreover, if West Fraser has permanently shut down the Kitimat mill or has commenced the process of permanently shutting down the Kitimat mill prior to January 1, 2009 then West Fraser may terminate the agreement with no buy-out payment, effective January 1, 2009 by giving the Company notice of termination prior to July 1, 2008. West Fraser's obligation to pay the minimum monthly charge will continue in effect until the Kitimat mill is permanently shut down. If the permanent shutdown is not completed by December 31, 2009, then the agreement with the Company will continue in force until the original expiry date of December 31, 2013. See "Risk Factors".

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 twelve months' notice of termination. No termination notice has been given.

During 2007, deliveries to Rio Tinto Alcan accounted for 7.5 percent of the Company's total gas deliveries and 4.1 percent of operating 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 billion investment, which would increase Rio Tinto Alcan's annual global primary aluminium production by more than 3 percent. Management expects that, if the project is completed, Rio Tinto Alcan's natural gas requirements would increase when the new capacity comes on-stream. The Company can give no assurances that the modernization project will be completed.

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. However, deliveries totalled 217.9 TJ in 2007 as the facility was operated in April 2007 after an avalanche damaged BC Hydro's electricity transmission line serving Prince Rupert.

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 is being amortized into income over the period March 1, 2006 to October 31, 2009.

Transportation service revenue in 2006 from Methanex was \$10.4 million lower than in 2005 due to the termination of the agreement with Methanex. This reduction was offset by credit amortization of \$5.6 million of the contract termination payment in 2006 resulting in a net margin reduction of \$4.8 million. The Company received approval in the Commission's decision on the Company's 2006 revenue requirements application to recover a projected revenue deficiency of \$4 million from its remaining customers, as \$0.8 million of the Methanex margin reduction was mitigated through other cost decreases. The net margin reduction in 2007, due to the Methanex contract termination, was approximately \$0.6 million. The Commission approved the recovery of a projected revenue deficiency of \$0.6 million in the Company's 2007

rates which included the impact of the 2007 Methanex net margin reduction. It will be necessary to seek further delivery charge rate increases as the contract termination payment is fully amortized in rates as of October 31, 2009.

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 2007, approximately 39 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 73 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 35 percent of that system's requirements. In Dawson Creek, approximately 9 percent of the required supply is 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 2007, 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

In 2007, the Company experienced a net increase of 62 customers, which was comprised of 317 net customer additions in the Northeast system and a net loss of 255 customers in the Western system.

In the Western system service area, there are few remaining candidates for conversion to natural gas in existing homes and businesses and limited opportunity to extend gas mains into unserviced rural areas. Also, with the exception of the Northeast system, local economies have been depressed as a result of uncertainty concerning future industrial activity levels. This lower level of customer additions is expected to prevail in the foreseeable future in the Western system service area.

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 a fixed rate method, under which rates are set 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"). The Commission uses a formula to determine, on an annual basis, the ROE applicable to a benchmark low-risk utility based on forecast long term Government of Canada bond rates plus a risk premium. The Company's risk profile is compared by the Commission to the benchmark low-risk utility to determine the Company's utility-specific risk premium relative to the ROE applicable to the benchmark low-risk utility. The Company's utility-specific risk premium is then added to the benchmark low-risk utility risk premium to determine the ROE which the Company is allowed to include in rates each year. The Company's ROE is therefore subject to variations in forecast long term Canada bond rates. The ROE is set by the Commission's formula in November each year to be applied in the following calendar 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 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.

The 2007 revenue requirements applications for each of the Company’s divisions were filed with the Commission in October 2006 for approval of new rates to take effect January 1, 2007. In early 2007 the Commission determined that written public hearing processes should be established to review the applications and set down regulatory timetables for the applications. Following the hearing processes, decisions on 2007 rates were rendered by the Commission in May 2007.

The 2008 revenue requirements applications for each division were filed with the Commission in early October 2007. The Company and its customers negotiated settlements of the 2008 revenue requirements applications and the settlements were approved by the Commission in late December 2007. As a result, the Company was able to set new rates effective January 1, 2008 on a permanent basis. Descriptions of the Commission’s determinations affecting 2007 rates and of the key elements of the negotiated settlements for 2008 are described below for each division.

Western System

The 2007 allowed rate of return on common equity for the Western system was 9.02 percent reflecting a 65 basis point premium over the low risk benchmark utility rate of return and based on a deemed common equity component of rate base of 40 percent.

The Commission’s 2007 revenue requirements decision contained minor adjustments to the applied for 2007 cost of service for rate making purposes. The Commission accepted the Company’s request to implement the decision by making the interim rates permanent effective January 1, 2007 with a deferral account to record the difference between the 2007 cost of service under the interim rates and the 2007 cost of service approved by the Commission in the decision. A debit of approximately \$50,000 before income taxes, for disposition in 2008, was recorded in

this deferral account. The Commission also approved the Company's request to credit \$0.9 million of deferred income taxes to the 2007 cost of service.

The Company sought approval in the 2007 revenue requirements application to commence amortizing in rates the costs incurred by the Commission and intervenors during the 2005 income trust application hearing of approximately \$256,000, before income taxes. The Commission denied recovery of these costs, negatively impacting 2007 earnings by approximately \$170,000.

The Commission also accepted the Company's forecast of gas supply costs for 2007. Rate riders were approved in various amounts for 2007 to refund a credit balance accumulated in the GCVA. In 2007, the reduction in customer revenue from credit rate riders totalled \$3.0 million, and was applied, on an after tax basis, to reduce the GCVA.

Under the 2008 negotiated settlement, the agreed upon rate increase was approximately 4.2 percent for the average residential customer. This increase included the impact of continuing to credit \$0.9 million of deferred income taxes to the 2008 cost of service, the same level of credit approved by the Commission with respect to the 2007 cost of service.

The gas supply commodity charge component of rates did not change as of January 1, 2008 compared to the rates effective October 1, 2007. The Commission reviews the gas supply commodity charges on a quarterly basis. The next potential change to the gas supply charge in rates will be April 1, 2008.

The forecast 2008 residential and commercial deliveries contained in the 2008 revenue requirements application for the Western system are approximately 3.3 percent lower than actual gas deliveries to these customer classes in 2007. Deliveries to small industrial customers are projected to be approximately 28 percent lower in 2008 compared to actual gas deliveries in 2007. The decrease is primarily due to two sawmills shutting down operations in 2007 pending recovery of the lumber industry and another sawmill curtailing lumber production due to low prices and the high Canadian dollar.

Prior to the commencement of each calendar year, the Commission resets the allowed rate of return on common equity for each of the Company's regulatory divisions by a formula which uses, among other things, a consensus forecast of yields on 10-year Government of Canada bonds for the forthcoming year. Largely as a result of the higher 10-year bond yields which were in effect in the latter part of 2007 relative to the same period in 2006, the consensus forecast of 2008 10-year bond yields increased relative to the late 2006 consensus forecast of 10-year bond yields for 2007. Through application of the formula the approved rates of return on common equity for the Company have increased. In November 2007, the Commission confirmed that the formula resulted in an 8.62 percent rate of return for a low risk benchmark utility in 2008 resulting in an allowable rate of return on common equity of 9.27 percent applicable to the Western system for 2008.

Northeast System

Fort St. John/Dawson Creek Division

The Fort St. John/Dawson Creek division allowed 2007 return on common equity was 8.77 percent with a deemed common equity component of 36 percent. The allowed rate of return on common equity includes a premium of 40 basis points over the low risk benchmark utility rate of return for the Fort St. John/Dawson Creek division.

The Commission accepted the Company's forecast of gas supply costs for 2007. Rate riders were approved in 2007 on a quarterly basis to refund credit balances in the GCVA. In 2007, customer refunds from rate riders totalled \$1.2 million, which was applied, on an after tax basis, to the GCVA.

The Commission's decision on the 2007 revenue requirements application contained minor adjustments to the applied for 2007 cost of service for rate making purposes. The Commission therefore agreed to implement the decision by making the interim rates permanent effective January 1, 2007 with minor rate adjustments effective July 1, 2007.

The negotiated settlement for 2008 rates provided for an increase of approximately 2.9 percent for the average residential customer in the Fort St. John/Dawson Creek division.

The forecast 2008 residential and commercial deliveries contained in the 2008 revenue requirements application for the Fort St. John/Dawson Creek system are approximately 1.6 percent higher than actual gas deliveries to these customer classes in 2007. Deliveries to small industrial customers are projected to be approximately 7.0 percent higher in 2008 compared to actual gas deliveries in 2007 primarily due to increased gas demand by oil and gas producers.

The gas supply commodity charge component of rates for the Fort St. John/Dawson Creek division did not change as of January 1, 2008 compared to the rates effective October 1, 2007. The Commission reviews the gas supply commodity charges on a quarterly basis. The next potential gas supply charge rate changes will be determined as of April 1, 2008.

The Commission's automatic return on equity adjustment formula resulted in an allowable rate of return on common equity of 9.02 percent applicable to the Fort St. John/Dawson Creek division for 2008.

Tumbler Ridge Division

The Tumbler Ridge division allowed 2007 return on common equity was 9.02 percent with a deemed common equity component of 36 percent. The allowed rate of return on common equity includes a premium of 65 basis points over the low risk benchmark utility rate of return for the Tumbler Ridge division.

The Commission's decision on the 2007 revenue requirements application contained minor adjustments to the applied for 2007 cost of service for rate making purposes. The Commission

therefore agreed to implement the decision by making the interim rates permanent effective January 1, 2007 with a deferral account to record the difference between the 2007 cost of service under the interim rates and the 2007 cost of service approved by the Commission in the decision. A credit of approximately \$50,000 before income taxes was recorded in the deferral account for disposition in 2008.

The negotiated settlement for 2008 rates provides for a rate decrease of approximately 3.8 percent for the average residential customer in the Tumbler Ridge division.

The gas supply commodity charge component of rates for the Tumbler Ridge division did not change as of January 1, 2008 compared to the rates effective October 1, 2007.

The Commission's automatic return on equity adjustment formula resulted in an allowable rate of return on common equity of 9.27 percent applicable to the Tumbler Ridge division for 2008.

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 four years ended December 31, 2008:

	Years ended December 31			
	2008	2007	2006	2005
Western system:				
Rate base.....	\$132,938	\$131,628	\$131,210	\$133,450
Common equity component.....	40.0%	40.0%	40.0%	N/A*
Allowed return on common equity	9.27%	9.02%	9.45%	9.68%
Fort St. John/ Dawson Creek division:				
Rate base.....	\$33,486	\$31,966	\$30,095	\$30,663
Common equity component.....	36.0%	36.0%	36.0%	36.0%
Allowed return on common equity	9.02%	8.77%	9.20%	9.43%
Tumbler Ridge division:				
Rate base.....	\$1,465	\$1,360	\$1,153	\$1,069
Common equity component.....	36.0%	36.0%	36.0%	36.0%
Allowed return on common equity	9.27%	9.02%	9.45%	9.68%

* Under the 2005 Negotiated Settlement for the Western system, the parties agreed the Common equity component would not be specified in the 2005 regulatory schedules.

Engineering and Operations

Social and Environmental Policies and Environmental Protection

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. The Company does not anticipate requirements to make any material capital expenditures for environmental compliance during 2008. The Company did not incur any specific expenditures on research and development during 2007 and does not expect to do so in 2008.

The Company's 2008 revenue requirements applications to the Commission included \$1.65 million for the estimated cost of permanent repairs to the break of a pipeline crossing on the Skeena River which occurred in June, 2007. This repair is currently underway. The applications also included \$1.5 million for the Upper Arden Valley rehabilitation project which was originally scheduled for completion in 2007. PNG deferred work on this project because of the unforeseen need to extend the Gitnadoix River pipeline bridge in early 2007 due to a change in the river pattern at a cost of \$2.1 million.

In-Line Inspection

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 2007 in-line inspection activity involved running an MFL tool through an 80 kilometer long section of eight-inch transmission pipeline as well as 25 kilometers of ten-inch transmission pipeline. The result of this inspection activity was favourable and will continue to be supported by subsequent investigations to confirm the integrity of the inspected sections of the line. The Company intends to continue its in-line inspection program in 2008 and into the foreseeable future on an annual basis.

Employees

At December 31, 2007, 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:

KSL Project

On July 17, 2006, the Company announced the formation of PTP for the purpose of developing the KSL Project. In addition, PTP and Kitimat LNG Inc. executed a Precedent Agreement to coordinate the process of obtaining authorizations for the KSL Project with the development of the Terminal. 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. PTP expects construction of the KSL Project facilities to commence in 2009 for completion in 2011.

In addition, construction of the KSL Project is subject to a number of conditions including the securing of LNG supply by Kitimat LNG Inc., financing of both projects and regulatory approvals for the KSL Project. The Company can give no assurances that these conditions will be met or that the construction of the terminal by Kitimat LNG Inc. and the 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.

As noted in the General Development of the Business section of this form, Management expects that the Company's share of development expenditures on the KSL Project will be approximately \$0.6 million (\$0.4 million after income taxes) in 2008. However, development costs incurred during this period may be higher than expected.

Liquidity, Cash Flow and Capital Availability Risks

The Company has several credit facilities, including a \$20 million operating line, a \$20 million 5-year term revolving credit facility and a \$15 million risk management facility. 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% or less. At December 31, 2007 the Company's debt to capitalization ratio was 49%. See "Management's Discussion and Analysis – Capital Resources – Short Term Debt". At December 31, 2007 the Company had borrowed \$8.9 million by way of overdraft on the operating line and had an outstanding letter of credit in the amount of \$1.8 million issued under the line to secure its obligations under its unfunded supplemental retirement plans. The letter of credit reduces the amount available under the operating line by its face value. The operating line is collateralized by a charge on the Company's accounts receivables and inventories.

The \$20 million 5-year term revolving credit facility was arranged effective August 3, 2007 through Canadian Western Bank and Roynat Inc., each committing \$10 million. This facility, which is available for general corporate purposes, also contains a financial covenant requiring the Company's debt to capitalization ratio not to exceed 65 percent. Further, if the Company's secured debt rating is less than BBB (low) or the Company has no debt rating, an additional financial covenant comes into effect requiring the Company to maintain an interest coverage ratio of 2.0 or higher using earnings before interest, income taxes and expenditures, to a maximum of \$10 million, on the KSL Project. While the covenant did not apply in 2007 as the Company's debt rating was BBB (low), the Company's interest coverage in 2007 was 2.04. This credit facility is collateralized by the pledge of a \$20 million debenture issued under the Company's Deed of Trust and Mortgage.

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. This facility is also collateralized by the pledge of a \$20 million debenture issued under the Company's Deed of Trust and Mortgage.

The Company requires long term debt to fund a portion of its capital and KSL Project development expenditures as well as scheduled debt amortization payments. On July 25, 2007 the Company's existing term lender Roynat Inc. refinanced its holdings of \$14 million of the Company's debentures that were scheduled to mature in 2011 and 2012, with a new \$15 million debenture issue maturing in 2017.

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 2007 was approximately 2 percent lower than in 2006 and 7 percent lower than in 2005. When prices are low, the prospects of fuel-switching and increased energy conservation pose a lesser risk to other energy sources that can be more cost competitive. 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.

Usage Risks

Natural gas competes with other forms of energy available to the Company's customers and end-users, including electricity, wood, coal and fuel oils 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, 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 areas served by the Company. 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 remained artificially low compared to market priced natural gas. Over time, this distortion in pricing signals may affect decisions by British Columbia consumers, potentially decreasing the use of natural gas by customers.

Over the past several years the average amount of natural gas consumed by residential customers has declined. This decline is consistent with that being experienced by other natural gas utilities in Canada and 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.

Potential for Termination of Large Industrial Contracts

In 2007, approximately 29 percent of energy deliveries were made to the Company's two largest industrial customers, Rio Tinto Alcan and West Fraser, representing approximately 9 percent of the consolidated operating margin of the Company. The Company's contract with West Fraser expires at the end of 2013 and may be terminated prior to that date upon payment of an amount described in the contract. In addition, if West Fraser has permanently shut down the Kitimat mill or has commenced the process of permanently shutting down the Kitimat mill prior to January 1, 2009 then West Fraser may terminate the agreement with no buy-out payment, effective January 1, 2009 by giving the Company notice of termination prior to July 1, 2008. In 2007, deliveries to West Fraser accounted for 20.1 percent of the Company's total gas deliveries and 1.5 percent of operating 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 2007, deliveries to Rio Tinto Alcan accounted for 7.5 percent of the Company's total gas deliveries and 3.8 percent of operating 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. The Company's gas deliveries to these customers have been and may in the future be affected by their ability to continue to operate 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. 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 deductibles

have been increased. 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.

The Government of Canada ratified the Kyoto Protocol on December 17, 2002 and the Protocol came into effect on February 16, 2005. Subsequently, several federal and provincial initiatives have been undertaken to address the issue of climate change, including the implementation of a carbon tax on fossil fuel consumption effective July 1, 2008 in British Columbia as set forth in the proposed provincial budget released on February 19, 2008. In early March 2008, the Federal Government announced its proposed framework of regulations to implement its industrial greenhouse gas emissions reduction strategy. Based on the information available from the announcement, the Company believes that its existing facilities will not be subject to the regulations due to the low level of greenhouse gas emissions from these facilities.

It is not possible at this time to measure the full extent of the cumulative impact of the Kyoto Protocol or the other federal and provincial initiatives on the Company. The Company will continue to monitor the development of climate change policies and initiatives.

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 can impact upon 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.

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 kilometers of the Company’s main pipeline and approximately nine kilometers 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, 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. Each of these factors could lead to increased volatility in the market price of the Common Shares. 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.

DIVIDENDS

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

	<u>2007</u>	<u>2006</u>	<u>2005</u>
Dividends per share			
- common	\$0.80	\$0.80	\$0.80
- preferred	\$1.69	\$1.69	\$1.69

On February 21, 2008 the Company announced an increase in the quarterly dividend to \$0.22 per Common Share payable March 20, 2008 to shareholders of record at the close of business on March 6, 2008. The Company pays a semi-annual dividend of \$0.84375 per preferred share on January 1 and July 1 of each year.

DESCRIPTION OF CAPITAL STRUCTURE

The Company's authorized share capital consists of 6,020,000 Common Shares with a par value of \$2.50 each, 1,400,000 cumulative redeemable junior preferred shares with a par value of \$10 (the "Junior Preferred Shares") and 200,000 6 ³/₄ percent cumulative redeemable preferred shares with a par value of \$25 each (the "Preferred Shares"). There are 3,664,580 Common Shares, no Junior Preferred Shares and 200,000 Preferred Shares issued and outstanding at March 13, 2008.

Common Shares

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

Cumulative Redeemable Junior Preferred Shares

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

6 ³/₄ Percent Cumulative Redeemable Preferred Shares

The Preferred Shares are entitled to the payment of fixed cumulative preferential cash dividends at the rate of 6 ³/₄ percent per annum on the amounts from time to time paid up thereon as when declared by the board of directors of the Company, have priority in the event of the liquidation, dissolution or winding up of the Company over the Common Shares, are non-voting and are redeemable at the option of the Company at \$26 per share plus any accrued and unpaid dividends at the date of redemption. The Company may not create shares ranking prior to the Preferred Shares but may create and issue other shares ranking on parity with those shares.

Ratings

The Company's preferred shares are currently rated Pfd-3(low) by Dominion Bond Rating Service ("DBRS") and the Company's secured debentures are rated BBB(low). On September 1, 2005, DBRS placed the ratings of the Company's preferred shares and secured debentures under review with negative implications, following the announcement of the termination of the Methanex agreement. As noted in its rating policies, if there is high uncertainty regarding the outcome of an event and DBRS is unable to provide an objective, forward-looking opinion in a timely fashion, then the rating(s) of the issuer(s) will be placed under review since the ratings may no longer be appropriate and can no longer be relied upon.

On July 24, 2007, DBRS removed the Company's secured debt rating from under review with negative implications, confirmed the ratings at BBB(low) and changed the trend to negative. With respect to the change to a negative trend, DBRS' rating policies published on their web site at www.dbrs.com include the following statements:

- “Using ‘Under Review Positive’ or ‘Under Review Negative’ is considered a more significant move than changing a rating trend to positive or negative.”
- “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.”

DBRS noted the following key challenges in arriving at the ratings in 2007 on the Company's long term debt and preferred shares:

- Economic development in the Western system service area.
- Competitiveness of natural gas versus alternative fuel sources.
- Potential cancellation of remaining industrial contracts and resulting regulatory treatment.
- Low interest rate environment negatively impacts earnings through approved return on equity.
- Deemed equity component viewed as low.

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.

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 Toronto Stock Exchange. The following table sets out the price ranges and volume traded for each month of the fiscal year ended December 31, 2007 for the common shares and the 6 3/4 percent preferred shares:

Common shares:	High	Low	Volume
January	\$18.40	\$17.77	125,734
February	18.25	17.87	101,799
March	18.18	17.50	105,422
April	18.15	17.65	146,658
May	18.15	17.52	149,980
June	18.15	17.58	187,888
July	18.50	17.61	95,242
August	18.42	17.71	89,435
September	18.50	17.75	167,212
October	18.75	18.00	68,483
November	18.49	18.10	98,332
December	19.00	18.15	42,261

Preferred shares:	High	Low	Volume
January	\$27.25	\$26.25	2,800
February	28.50	26.75	1,325
March	26.51	26.51	200
April	27.30	26.11	3,950
May	27.00	26.50	627
June	26.51	26.10	625
July	26.50	25.99	1,200
August	26.25	26.25	100
September	26.75	26.01	1,400
October	26.05	26.05	400
November	26.11	26.01	1,350
December	26.50	25.01	500

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 table sets 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 2.9 percent of the

issued and outstanding common shares of the Company.

Directors

Name, Principal Occupation and Other Information	<i>Beneficial Ownership or Control of Common Shares at March 13, 2008</i>	<i>Number of DSU's at March 13, 2008⁽⁶⁾</i>	<i>Value of DSU's at March 13, 2008⁽⁶⁾</i>
Robert F. Chase: Chair of the Board; President and Chief Executive Officer of New West Energy Services Inc. (formerly Lexacal Investment Corp.) (an oil and gas services company); resident in British Columbia, Canada; a director of the Company since April 26, 1995 ^{1, 4, 5}	Nil	2,937	\$53,363
Wayne M. Bingham: Executive Vice-President and Chief Financial Officer, Superior Plus Income Fund; resident in Alberta, Canada; a director of the Company since April 26, 2007 ^{2, 4}	Nil	436	\$7,929
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	66,225	--	--
Diane M. Fulton: Executive Director, Investments, University of British Columbia Faculty Pension Plan; resident in British Columbia, Canada; a director of the Company since August 8, 2005 ^{2, 5}	Nil	802	\$14,569
Hugh C. Morris: Corporate Director; resident in British Columbia, Canada; a director of the Company since May 1, 1986 ^{1, 3}	400	905	\$16,444
David G. Unruh: Corporate Director; resident in British Columbia, Canada; a director of the Company since March 21, 2002 ^{3, 4}	Nil	1,756	\$31,910

Name, Principal Occupation and Other Information	<i>Beneficial Ownership or Control of Common Shares at March 13, 2008</i>	<i>Number of DSU's at March 13, 2008⁽⁶⁾</i>	<i>Value of DSU's at March 13, 2008⁽⁶⁾</i>
Arthur H. Willms: Corporate Director; resident in British Columbia, Canada; a director of the Company since April 28, 1983 ^{1,5}	Nil	906	\$16,454
Janet P. Woodruff: Vice President, Corporate Services and Chief Financial Officer, 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	530	\$9,635

(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 value of the DSU's is calculated using the average closing price per share for the ten trading days immediately preceding the March 13, 2008 valuation date.*

Officers

<i>Name, position and other information</i>	<i>Beneficial Ownership or Control of Common Shares at March 13, 2008</i>
<u>Robert F. Chase</u> Chairman of the Board British Columbia, Canada	Nil

<i>Name, position and other information</i>	<i>Beneficial Ownership or Control of Common Shares at March 13, 2008</i>
<u>Roy G. Dyce</u> President and Chief Executive Officer British Columbia, Canada	66,225
<u>Greg B. Weeres</u> Vice President, Operations and Engineering, British Columbia, Canada	15,238
<u>Janet P. Kennedy</u> Vice President, Finance British Columbia, Canada	Nil
<u>Kevin R. Teitge</u> Director, Corporate Development and Treasurer British Columbia, Canada	15,385
<u>Craig P. Donohue</u> Director, Regulatory Affairs & Gas Supply and Assistant Secretary British Columbia, Canada	8,538
<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. 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; Mr. K.R. Teitge was an independent consultant from June 2003 through January 2004 and was Director, Corporate and Project Finance, Westcoast Energy Inc. prior to January 1999 until June 2003; 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

Mr. Chase, Ms. Fulton and Ms. Woodruff served as members of the Audit Committee from January 1, 2007 to April 26, 2007. Mr. Bingham replaced Mr. Chase on the Audit Committee on April 26, 2007. For the remainder of the fiscal year the Audit Committee was comprised of Ms. Woodruff (Chair), Ms. Fulton and Mr. Bingham. 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 and subsequently Chief Financial Officer of BC Transmission Corporation.

Ms. Fulton holds a Masters of Business Administration from York University and is a member of the Boards of Directors, the Investment Committee and the Governance Committee of the Insurance Corporation of British Columbia. She has over twenty years experience in investment banking and investment fund management.

Mr. Bingham has over 25 years experience in financial and capital markets. Prior to attaining his current position as Executive Vice President and Chief Financial Officer of Superior Plus Income Fund, 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 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, 2007, 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, 2007 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 provides 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, including reimbursements for expenses, for professional services rendered by Deloitte & Touche LLP to the Company were:

	Audit Fees	Audited-Related Fees⁽¹⁾	Tax Fees⁽²⁾	All Other Fees
2007	\$145,000	\$46,850	---	---
2006	\$130,000	\$63,100	---	---

(1) Audit-related fees pertain to attendance at interim audit committee meetings, consultation on accounting matters and audit of pension and savings plans.

(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 2005, 2006, or 2007.

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 dated March 17, 2008 for the Company's 2008 Annual Meeting of

Shareholders. Additional financial information is provided in the Company's consolidated financial statements for the year ended December 31, 2007. Management's Discussion and Analysis of the Company's 2007 Annual Report 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”

AUDIT COMMITTEE

TERMS OF REFERENCE

PURPOSE

The overall purpose of the Audit Committee is to ensure that: (i) the Corporation’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 Corporation, (iii) to review the Corporation’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 Corporation (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 Corporation’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 Corporation 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 Corporation 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 Corporation'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, if any, 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 Corporation as it deems necessary.
15. In discharging its responsibilities, the Committee shall have full access to all books, records, facilities and personnel of the Corporation, to the Corporation's legal counsel and to such other information respecting the Corporation 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 Corporation'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 Corporation'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 Corporation's independent auditors and internal auditors (if any) and assess their performance;
- d) to ensure that the management of the Corporation 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 Corporation;
- 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 Corporation 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 review the engagement reports of the independent auditors on unaudited financial statements of the Corporation including any quarterly interim reviews that may be requested by the Corporation, and to review with the independent auditors, upon completion of their audit:
 - i) contents of their report;
 - ii) scope and quality of the audit work performed;
 - iii) adequacy of the Corporation's financial and auditing personnel;
 - iv) co-operation received from the Corporation's personnel during the audit;
 - v) internal resources used;
 - vi) significant transactions outside of the normal business of the Corporation;
 - vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles and management systems;
 - viii) the quality, acceptability and integrity of the Corporation'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 Corporation's financial statements;and report to the Board in respect of the foregoing;
- f) 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

- g) 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 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 Corporation's internal auditors (if in place) are to:

- a) periodically review the internal audit function with respect to the organization, staffing and effectiveness of the internal audit department;
- b) review and approve the internal audit plan; and
- c) 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 Corporation are to:

- a) review the adequacy, appropriateness and effectiveness of the Corporation's policies and business practices which impact on the integrity, financial and otherwise, of the Corporation, 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 Corporation'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 Corporation;
- d) periodically review the Corporation's accounting and auditing policies, practises and procedures and the extent to which recommendations made by the internal audit staff (if any) 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 Corporation.

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 filings and decisions as they relate to the Corporation's consolidated financial statements;
- c) ensure adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation'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 Corporation 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 Corporation 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 Corporation;
- 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 Corporation regarding accounting, internal controls, or auditing matters; and

- ii) the confidential, anonymous submission by employees of the Corporation 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 Corporation;
- 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 Policies and Procedures for the Employees' Retirement Plan and other Plans as required and any amendments required thereto;
- b) Appoint the auditors, review the scope of the audit plan and review and approve the audited financial statements for the Employees' Retirement Plan, the Supplemental Executive Retirement, the Employee Savings Program, the Group RRSP and the non-pension post-retirement benefits (collectively, the "Plans");
- c) Receive a report from the Pension and Savings Plan Committee (the "PSPC") after each of its meetings and report to the Board thereon;
- d) Receive semi-annually a report from the PSPC including (i) a summary of the activities of the PSC during the relevant period; (ii) a summary and evaluation of the investment performance of the funds associated with the Plans (the "Funds") for the applicable period; (iii) where there has been any change in any Investment Manager during the relevant period, a summary of the factors leading up to the decision for such change, a report on the process that was undertaken to implement such change and a summary of the factors that influenced the decision of the Committee in selecting any new Investment Manager; and (iv) where there has been any change in any third party providers of pension-related services during the relevant period (other than changes in Investment Managers), including actuaries, auditors, pension consultants and outsourcers of pension administration, a report on such change; and report to the Board thereon.
- e) Receive an annual report from the PSPC including (i) the audited financial statements of the Plans and the Funds; (ii) a summary of the changes in the liabilities of the Plans with sensitivity analysis to interest rates, demographic factors and any other factors that may be indicated from time to time; (iii) The Statement of Investment Policy and Procedures for each of the Funds, containing such amendments as have been recommended by the PSPC.

7. **Calendar**

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

Revised: March 13, 2008

APPENDIX A

AUDIT COMMITTEE

CALENDAR OF ACTIVITIES

	<u>Feb</u>	<u>Mar</u>	<u>April</u>	<u>July</u>	<u>Oct</u>
Review and Approve Financial Statements and Reports:					
• Financial Statements.	✓		✓	✓	✓
• Interim Report, including MD&A.			✓	✓	✓
• Annual Report, including MD&A.	✓				
• Annual Information Form.		✓			
• Review Major Accounting Policies and Significant Estimates.	✓	✓	✓	✓	✓
• Consider Changes in Accounting Principles and Whether Industry/Standards are Being Followed.	✓	✓	✓	✓	✓
• Consider Unresolved Differences of Opinion Between Management and the Auditor.	✓	✓	✓	✓	✓
External Auditors:					
• Review Scope of Audit and Audit Plan.				✓	
• Discuss Audit Report and Findings.	✓				

	<u>Feb</u>	<u>Mar</u>	<u>April</u>	<u>July</u>	<u>Oct</u>
• Review Recommendations and Response to Audit Report.	✓				
• Review Auditor Independence.	✓	✓	✓	✓	✓
• Review Cooperation and Services Provided by Management.	✓	✓	✓	✓	✓
• Recommend Appointment of Auditors.	✓				
• Review Audit Fees.	✓				
• Meeting with Auditors - without Management.	✓	✓	✓	✓	✓
• Review Non-Audit Services.	✓	✓	✓	✓	✓

Risk Management and Control:

• Review Effectiveness of Internal Audit Function and Review the Internal Audit Plan (if any).			✓		
• Review Internal Audit Findings (if any).				✓	
• Review of Disclosure Controls and Procedures.	✓	✓	✓	✓	✓
• Annual Assessment of Compliance with the Code of Business Ethics.	✓				
• Review of Deferred Charges.	✓		✓	✓	✓
• Receive Report on Derivatives.	✓		✓	✓	✓
• Adequacy of Allowance for Doubtful Accounts.	✓		✓	✓	✓

	<u>Feb</u>	<u>Mar</u>	<u>April</u>	<u>July</u>	<u>Oct</u>
• Review of Incidents Raised Through the Whistleblower Program.	✓	✓	✓	✓	✓
• Assessment of Adequacy of Insurance Coverage.	✓				
• Review Philosophy on Control and Information Systems.				✓	
• Annual Review of Compliance with Legal and Regulatory Responsibilities.	✓				
• Annual Review of Delegation of Authority to Management and of Management's Compliance.	✓				
Pension and Savings Plans Committee:					
• Receive Minutes of Meetings of PSPC	✓		✓	✓	✓
• Receive Semi-Annual Report from PSPC	✓			✓	
• Receive Annual Report from PSPC			✓		
• Appoint Auditors and Review Scope of Audit for the Funds.			✓		
• Review Audited Financial Statements for the Funds.				✓	
Other:					
• Adequacy of Complement in Accounting, Customer Billing and Finance.					✓
• Assess Circumstances Adverse to the Company.	✓	✓	✓	✓	✓
• Review any Material Litigation.	✓	✓	✓	✓	✓

	<u>Feb</u>	<u>Mar</u>	<u>April</u>	<u>July</u>	<u>Oct</u>
• Monitor Procedures for Reviewing Officers' Expenses.					✓
• Review Appointment of Financial Personnel			✓		
• Review Terms of Reference and Calendar of Activities for Ensuing Year.					✓