

NORTH PEACE ENERGY CORP.
ANNUAL INFORMATION FORM
FOR THE YEAR ENDED
DECEMBER 31, 2009

April 20, 2010

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ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	standard tank barrels

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule
MM	Million

Other

AECO	A natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
ARTC	Alberta Royalty Tax Credit
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/d	barrel of oil equivalent per day
m ³	cubic metres
MBOE	1,000 barrels of oil equivalent
\$000s	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Where any disclosure of reserves data is made in this annual information form (or the Appendices hereto) that does not reflect all reserves of North Peace Energy Corp., the reader should note that the estimates of reserves and future net revenue for individual properties or groups of properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres (Alberta)	Hectares	0.400
Hectares (Alberta)	Acres	2.500
Acres (British Columbia)	Hectares	0.405
Hectares (British Columbia)	Acres	2.471

Disclosure of Contingent Resources

In this Annual Information Form, North Peace has disclosed estimated volumes of "contingent resources" that have been prepared by Sproule pursuant to the Sproule Report and which relate to the Red Earth Project.

"**Resources**" are quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, including the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered.

"**Contingent resources**" are defined as those quantities of petroleum estimated, on a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early project stage. It should not be assumed that the estimates of recovery, production and net revenue presented in the tables above represent the fair market value of the Corporation's bitumen resources. There is no assurance that the forecast prices and cost assumptions will be realized and variances could be material. The recovery and production estimates of the Corporation's bitumen resources are only estimates and there is no guarantee that the estimated resources will be recovered or produced. Actual resources may be greater than or less than the estimates provided herein. There is no certainty that it will be commercially viable to produce any portion of the resources.

The following are contingencies which currently prevent the classification of the Contingent Resources at the Corporation's Red Earth Block B South as reserves: the current CSS Pilot results have not yet demonstrated commerciality, lack of regulatory approval, absence of a firm development plan, or the uncertainty of funding, approval for development. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be sub classified based on project maturity and/or characterized by their economic status. All figures reflect the Corporation's gross Contingent Resources, which are the Corporation's working interest share of the Contingent Resources, before deduction of any royalties.

"**Discovered Bitumen Initially-In-Place**" (equivalent to Discovered Bitumen Resources) is that quantity of bitumen that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of Discovered Bitumen Resources includes production, reserves, and contingent resources; the remainder is unrecoverable.

Resources and contingent resources do not constitute, and should not be confused with, reserves. See "Red Earth Project – North Central Alberta", "Risk Factors — Project Risks" and "Risk Factors – Uncertainties Associated with Estimating Resource Volumes"

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**ABCA**" means *Business Corporations Act* (Alberta);

"**CSS**" means cyclic steam stimulation, a method also commonly known as "Huff and Puff ", consisting of 3 stages: injection, soaking and production. First, steam is injected into a well at a temperature of approximately 300°C (575°F) for a period of weeks to months; then, the well is allowed to sit for a shorter period of days to weeks to allow heat to soak into the formation; and, lastly, the well is put on production where the hot oil is pumped from the well for a period of weeks or months. Once the production has decreased to a marginal rate, the well is put through another cycle of injection, soak and production;

"**CSS Pilot**" means the Corporation's CSS pilot project on its lands in the Red Earth area of Alberta;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" means the Common Shares in the capital of the Corporation;

"**Corporation**" or "**North Peace**" means North Peace Energy Corp.;

"**ERCB**" means the Energy Resources Conservation Board;

"**NI 51-101**" means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities;

"**NRF**" means the New Royalty Framework announced by the Alberta government on October 25, 2007;

"**Red Earth Project**" means North Peace's 100% working interest in four blocks of oil sands leases extending over approximately 86,400 gross acres of land in the Red Earth Area of Alberta;

"**Sproule**" means Sproule Associates Limited;

"**Sproule Report**" means the report of Sproule dated February 3, 2010 evaluating the resources of the Corporation as at December 31, 2009; and

"**TSXV**" means the TSX Venture Exchange.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2009.

All dollar amounts herein are in Canadian dollars, unless otherwise stated.

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, management's assessment of future plans and operations, financial and business prospects and financial outlook, reserve and production estimates, drilling plans, activities to be undertaken in various areas, criteria and considerations in participations and acquisitions, timing of drilling, recompletion and tie in of wells, tax horizon, timing of development of undeveloped reserves, estimated abandonment and reclamation costs and the timing thereof and planned capital expenditures, the timing thereof, the method of funding and anticipated effect on reserves and future net revenue may be forward looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will", "should", "could",

"anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions have been used to identify these forward looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward looking statements including, but not limited to, changes in general economic and market conditions, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of North Peace's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although North Peace believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because North Peace can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which North Peace operates; the timely receipt of any required regulatory approvals; the ability of North Peace to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which North Peace has an interest in to operate the field in a safe, efficient and effective manner; the ability of North Peace to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of North Peace to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which North Peace operates; the ability of North Peace to successfully market its oil and natural gas products; the business and operations strategies including the completion of North Peace's pilot project and potential commencement of a subsequent commercial project. In addition, information and statements relating to "resources" are deemed to be forward looking information and statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources described exist in the quantities predicted or estimated, and that the resources described can be profitably produced in the future.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could effect North Peace's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), and at North Peace's website (www.northpec.com). Although the forward looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward looking statements. Investors should not place undue reliance on forward looking statements. These forward looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

BACKGROUND

General History

North Peace was incorporated as Juno Capital Corp. ("**Juno**") which was incorporated pursuant to the ABCA on April 10, 2003. By a certificate of amendment issued on June 18, 2003 the Corporation amended its articles to remove its "private company" restrictions. Juno was a "Capital Pool Company" under the rules and policies of the TSXV and completed its "Qualifying Transaction" on February 6, 2007 by way of an amalgamation with North Peace Energy Inc. to form North Peace Energy Corp.

The head office of the Corporation is located at Suite 630, 505 – 3rd Street S.W., Calgary, Alberta, T2P 3E6 and the registered office of the Corporation is located at 1400, 350 – 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

The Common Shares of the Corporation are presently listed and posted for trading on the TSXV under the symbol "NPE".

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a summary of the business operations of the Corporation for the periods shown.

2007

On February 6, 2007, the Corporation completed its "Qualifying Transaction" (the "**Transaction**") with North Peace Energy Inc. to acquire all of the issued and outstanding common shares of North Peace Energy Inc. in exchange for ten common shares of Juno for each issued and outstanding common share of North Peace Energy Inc. All outstanding and unexercised stock options and warrants of North Peace Energy Inc. were exchanged for equivalent stock options and warrants of Juno having regard for the foregoing ten for one ratio.

Upon completion of the Transaction, Juno consolidated its common shares on the basis of one consolidated common share for each five issued and outstanding common shares, and amalgamated with North Peace Energy Inc. to form the Corporation under the name "North Peace Energy Corp."

In the second quarter of 2007, the Corporation raised approximately \$20 million through a bought-deal financing and used the proceeds thereof to purchase from Peace Oil Corp. the remaining 30% working interest partner in its land holdings in the Red Earth area of Alberta. Total consideration for the acquisition was \$20 million consisting of \$15 million in cash and \$5 million in common shares of the Corporation issued at a deemed price of \$2.20 per share.

In October 2007, the Corporation announced that it had formally filed its application with the EUB for a 2 well, 1,000 barrel per day cyclic steam stimulation ("**CCS**") pilot project (the "**CCS Pilot**") on Block B South of the Red Earth Project.

2008

In 2008, North Peace completed environmental work for its Red Earth Alberta CSS Pilot. In addition it completed its 2007/2008 drilling program with the drilling of eight additional delineation wells on its lands bringing the total to 17.

In June, 2008, the Corporation received ERCB approval for the CSS Pilot and announced a private placement offering of 13,333,300 units of the Corporation at a price of \$1.50 per unit for gross proceeds of approximately \$26 million. The proceeds of the offering were used by the Corporation to fully fund the costs associated with the construction of the CSS Pilot.

In August, 2008, the Corporation drilled and completed 2 horizontal CSS oil wells for steam injection and oil production. Construction of the pilot facility commenced in September, 2008.

2009

In the first quarter, 2009, the Corporation announced the injection of "first steam" into the pilot project's first well.

In Q2 2009, the Corporation announced that it had commenced production of bitumen at its CSS Pilot and had commenced steaming on the Corporation's second horizontal oil well. Additionally, North Peace completed a private placement financing of 21,109,000 units at a price of \$0.55 per unit for proceeds of approximately \$11.6 million.

In Q4 2009, the Corporation participated in the drilling of 5 conventional oil wells outside the Red Earth area resulting in 3 successful wells (1.6 wells net to North Peace). Sproule Associates has assigned 177,800 barrels of proved plus probable reserves to these wells net to North Peace.

In December 2009, the Corporation drilled 10 delineation wells on its oil sands leases. Sproule Associates Limited re-affirmed the Discovered Bitumen Initially-In-Place on the Red Earth Project lands at 2.1 billion barrels of bitumen. In addition, Sproule assigned High (P10), Best (P50) and Low (P90) Contingent Resource volumes of 146, 105, and 64 million barrels of bitumen respectively.

RECENT DEVELOPMENTS

On February 4, 2010, North Peace's Board of Directors initiated a process to explore strategic alternatives with a view to enhancing shareholder value. The Company engaged CIBC World Markets Inc. ("**CIBC**") to provide financial advisory services to assist in this strategic review. Strategic alternatives may include, but are not limited to, a corporate sale, merger or other business combination, joint venturing with an interested party, a major financing or any other combination. The Board established a Special Committee of independent directors to work with management and the Company's external advisors and to supervise the strategic review process.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Exploration and Development Strategy

General Development of the Business

North Peace has an early stage in-situ oil sands play in northern Alberta with a Sproule estimated 2.1 billion barrels of Discovered Bitumen Initially-In-Place. The Corporation has a 100% working interest in 86,400 acres of Crown oil sands leases at Red Earth in the Peace River area. The lands have the benefit of over 300 legacy logs and are surrounded by accessible oil and gas production infrastructure. The target Bluesky zone is a regional sand, deposited in a near shore marine environment at approximately 400 metres in depth. The initial focus area has approximately 22 sections (86,400 acres) which management estimates has oil bearing thickness ranging for 10 to 16 metres, expected to be technically sufficient to advance a 30,000 bbl/d commercial project. North Peace is currently advancing the development of its resource using a robust and proven in-situ thermal recovery process, CSS. The CSS Pilot, consisting initially of two horizontal CSS wells has been built and the facility has been producing since May 2009.

The CSS process is a two phase process consisting of: (1) the steam injection phase, which consists of (a) steam being injected at high pressure into oil sand formation for several weeks, (b) steam heats bitumen (reduces viscosity), and (c) high steam injection pressures create fissures in formation thereby maximizing bitumen contact and production; and (2) the production phase, wherein (a) steam injection is stopped and heat dissipates in reservoir (soak), and (b) the well is produced for several months until temperature and production rates decline.

North Peace continues to advance its Red Earth asset to commercial production. The CSS Pilot plant has been operational since the start of 2009 with the principal objective of demonstrating the feasibility of producing economic quantities of bitumen from the Corporation's resource and validating economic and technical parameters to optimize the design of future commercial development.

Narrative Description of the Business

General

North Peace holds a 100% working interest in four large blocks of oil sands leases extending over approximately 86,400 gross acres of land in the Red Earth Area of Alberta (the "**Red Earth Project**") In addition, North Peace holds interest in three producing conventional oil wells in two areas of the Peace River Arch of Alberta.

Red Earth Project Area – North Central Alberta

Property Description and Location

North Peace's Red Earth acreage is located in a part of the Peace River and Athabasca oil sands deposit areas. Specifically, North Peace's acreage is located near the hamlet of Red Earth in North-Central Alberta (see Exhibit "1", below).

Exhibit "1"



North Peace operates the CSS pilot and has been producing bitumen since May 2009 from 2 horizontal wells. Cumulative production to date is in excess of 20,000 barrels of Bitumen. In addition, North Peace has drilled 27 delineation wells which it had core samples taken and analysed.

Regional Geology and Structural Setting

North Peace's oil sands leases are located in the Red Earth area of north-central Alberta. Here, Lower Cretaceous strata rest uncomfortably on the Paleozoic erosional surface at depths of less than 500 metres in the vicinity of the Red Earth Highlands, a locally emergent block during early Cretaceous time. This area lies off the eastern limits of the ancient Peace River Arch, with its associated deep-seated faulting and fringing Paleozoic reef trends. Regional stratigraphic dip of the Cretaceous strata is to the southwest. Local structurally high and low areas are commonly related to paleotopography on the underlying Paleozoic carbonates.

The principal Bitumen target is the Bluesky Formation. The Bluesky Formation was deposited under estuarine to shallow marine conditions, flanking the Red Earth highlands. Widespread, fine-grained, relatively unconsolidated oil sands have been encountered across the area. Thicker sands appear to consist of stacked units with thin shale intervals creating vertical permeability barriers within the section.

Reservoir Properties and Resource Estimates

North Peace has cut 26 cores through the target Bluesky reservoir in this area as historical exploration and development drilling have been for deeper targets.

From core analyses, permeabilities range up to 10,000 millidarcies, oil gravities range up to 11 °API, and oil saturations reach as high as 75 percent.

The CSS Pilot is currently producing 10° API Bitumen. Sproule Associates has estimated there are 14.5 square miles containing 583 million barrels of Discovered Bitumen Initially In Place where the thickness of the Bluesky is in excess of 10 metres on North Peace's lands. Sproule has assigned Contingent Resources of 146 million barrels (high P10), 105 million barrels (Best P50), and 64 million barrels Low (P90) to this portion of the Corporation's lands.

Sproule has estimated that in aggregate North Peace's Red Earth lands contain 2.1 billion barrels of Discovered Bitumen Initially In Place.

Operations

North Peace achieved first steam injection in January 2009 and first oil in May 2009 from the CSS Pilot. The CSS Pilot wells consist of two horizontal CSS wells, and three observation wells. The CSS Pilot facilities consist of: water source, water softening, steam generation, emulsion cooling, emulsion storage, produced water disposal, and flare systems. The emulsion is trucked to third parties for final water separation, if required, and blending to pipeline specifications. To date the Corporation's pilot wells have produced in excess of 20,000 bbl of Bitumen.

Conventional Oil – Peace River Arch Area – North Central Alberta

Property Description and Location

North Peace has 3 (1.6 net) producing conventional oil wells and 8.75 (4.625 net) sections of P&NG mineral rights. The Corporation's two horizontal wells currently produce from the Montney formation. The Corporation's other conventional oil well produces from the Charlie Lake formation.

BITUMEN RESOURCES – RED EARTH PROJECT

Independent Resource Evaluation

North Peace engaged Sproule to prepare an evaluation of the Corporation's bitumen resources at its Red Earth Project as of December 31, 2009 (the "**Sproule Report**"). This included a geological and economic evaluation of all of North Peace's oil sands leases.

Contingent Resources and the associated net present values were determined based on exploitation using conventional CSS followed by a Steam Drive component. Certain well pads of Shell Canada Limited's Peace River project were used by Sproule as an analogue in their analysis.

Discovered Bitumen Initially-In-Place⁽¹⁾⁽⁶⁾	
	(MMbbl)
Block A	210
Block B North	186
Block B South	1,252
Block C	351
Block D	70
Total Red Earth (all lands)	2,069
Block B South	
Total	1,252
Inside 6 m contour	1,112

Discovered Bitumen Initially-In-Place⁽¹⁾⁽⁶⁾

	(MMbbl)
Inside 8 m contour	974
Inside 10 m contour	610
Inside 10 m contour (area with top gas excluded)	583

Contingent Resources⁽²⁾⁽⁶⁾

	High ⁽³⁾	Best ⁽³⁾	Low ⁽³⁾
Contingent Resource (MMbbl) ⁽²⁾	146	105	64
Recovery Factor ⁽⁴⁾	25%	18%	11%

Net Present Value of Future Cash Flow⁽⁵⁾⁽⁶⁾ (MM\$)

	0%	5%	8%	10%
High Estimate ⁽³⁾	\$3,272	\$945	\$495	\$327
Best Estimate ⁽³⁾	\$1,688	\$414	\$171	\$81
Low Estimate ⁽³⁾	(\$184)	(\$260)	(\$266)	(\$263)

Notes:

- (1) "Discovered Bitumen Initially-In-Place" (equivalent to Discovered Bitumen Resources) is that quantity of bitumen that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of Discovered Bitumen Initially-In-Place includes production, reserves, and contingent resources; the remainder is unrecoverable.
- (2) "Contingent Resources" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. Sproule has identified the following as contingencies which currently prevent the classification of the Contingent Resources at the Corporation's Red Earth Block B South as reserves: current CSS pilot results not yet demonstrated commerciality, lack of regulatory approval, absence of a firm development plan, or the uncertainty of funding approval for development. It is also appropriate to classify as Contingent Resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be sub classified based on project maturity and/or characterized by their economic status. All figures reflect the Corporation's gross Contingent Resources, which are the Corporation's working interest share of the Contingent Resources, before deduction of any royalties.
- (3) A low estimate is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation (90 percent probability), a best estimate is considered to be the best estimate of the quantity that will actually be recovered from the accumulation (50 percent probability) and a high estimate is considered to be an optimistic estimate of the quantity that will actually be recovered from the accumulation (10 percent probability).
- (4) Recovery factors are based on certain well pads of Shell's Peace River Project and applied to 583 million barrels inside the 10 metre contour and excluding the south east gas cap area of Block B South.
- (5) Net present value ("NPV") represents the Corporation's share of future net revenue before the deduction of income taxes. The calculation considers such items as revenues, royalties, operating costs, abandonment costs and capital expenditures. The calculation does not consider financing costs and general and administrative costs. All NPVs are calculated assuming natural gas is used as a fuel for steam generation. Revenues and expenditures were calculated based on Sproule's forecast prices and costs as of December 31, 2009.
- (6) It should not be assumed that the estimates of recovery, production and net revenue presented in the tables above represent the fair market value of the Corporation's bitumen resources. There is no assurance that the forecast prices and cost assumptions will be realized and variances could be material. The recovery and production estimates of the Corporation's bitumen resources are only estimates and there is no guarantee that the estimated resources will be recovered or produced. Actual resources may be greater than or less than the estimates provided herein. There is no certainty that it will be commercially viable to produce any portion of the resources.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The following is a summary of reserves data and other oil and gas information of North Peace as at December 31, 2009. The reserves were evaluated by Sproule effective December 31, 2009, as contained in the Sproule Report dated February 3, 2010.

Disclosure of Reserves Data

The reserves data set forth below is based upon the Sproule Report. The Sproule Report summarizes the crude oil, bitumen and natural gas reserves of North Peace and the net present values of future net revenue for these reserves using forecast prices and costs. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. North Peace engaged Sproule to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of North Peace's reserves are in Canada and, specifically, in the province of Alberta.

The Report on Reserves Data by Independent Qualified Reserves Evaluators in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Schedules "A" and "B", respectively, to this AIF.

Disclosure provided herein in respect of Boes and Mcfes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf : 1 bbl and an Mcfe conversion ratio of 1 bbl : 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The information relating to the oil and gas reserves of North Peace contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs, anticipated production and abandonment costs. Refer to "Forward-Looking Statements" and "Risk Factors".

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of North Peace's crude oil, bitumen and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves and Future Net Revenue Data (Forecast Prices and Costs)

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS**

Reserves Category	Light and Medium Oil		Natural Gas		Heavy Oil	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)
Proved Developed Producing	0.0	0.0	120	105	30.3	27.9
Proved Developed Non-Producing	17.1	15.9	0	0	0.0	0.0
Proved Undeveloped	0.0	0.0	120	106	26.7	24.3
Total Proved	17.1	15.9	240	211	57.0	52.2
Total Probable	14.9	12.9	121	103	28.4	24.5
Total Proved Plus Probable	32.0	28.8	362	314	85.4	76.7

Net Present Values Of Future Net Revenue (\$000s)

Reserves Category	Before Income Taxes Discounted At (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/year
	0	5	10	15	20	0	5	10	15	20	
Proved Developed Producing	1,707	1,425	1,225	1,078	966	1,707	1,425	1,225	1,078	966	26.93
Proved Developed Non-Producing	871	788	719	659	609	871	788	719	659	609	45.15
Proved Undeveloped	1,039	720	501	346	233	1,039	720	501	346	233	11.97
Total Proved	3,617	2,933	2,445	2,084	1,808	3,617	2,933	2,445	2,084	1,808	23.67
Total Probable	2,720	1,781	1,266	959	762	2,720	1,781	1,266	959	762	23.21
Total Proved Plus Probable	6,337	4,713	3,711	3,043	2,569	6,337	4,713	3,711	3,043	2,569	23.51

TOTAL FUTURE NET REVENUE (\$000s)
(UNDISCOUNTED)
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS

<u>Reserves Category</u>	<u>Revenue</u>	<u>Royalties</u>	<u>Operating Costs</u>	<u>Capital Development Costs</u>	<u>Abandonment Costs</u>	<u>Future Net Revenue Before Income Taxes</u>	<u>Future Income Taxes</u>	<u>Future Net Revenue After Future Income Taxes</u>
Proved	7,685	655	2,466	832	115	3,617	0	3,617
Proved Plus Probable	12,851	1,338	4,212	832	132	6,337	0	6,337

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS

<u>Reserves Category</u>	<u>Production Group</u>	<u>Future Net Revenue Before Income Taxes (discounted at 10%/year) (\$000s)</u>	<u>Unit Value Before Income Taxes (discounted at 10%/year) (\$/boe)</u>
Proved ,	Light and Medium Oil ⁽¹⁾	719	45.15
	Heavy Oil	1,726	19.76
	Natural Gas (including by-products but excluding solution gas)	0	0
	Total	2,445	23.67
Proved Plus Probable	Light and Medium Oil ⁽¹⁾	1,276	44.37
	Heavy Oil	2,435	18.86
	Natural Gas (including by-products but excluding solution gas)	0	0
	Total	3,711	23.51

Note:

- (1) Including solution gas and other by-products.

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.
2. The crude oil, natural gas liquids and natural gas reserve estimates presented in this Appendix "F" are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below:

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates:

- (a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- (b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

- (c) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non producing.
 - (i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
 - (ii) **Developed non producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.
- (d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing

and developed non producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

Forecast Prices and Costs

Forecast prices and costs are those:

- (a) generally acceptable as being a reasonable outlook of the future; and
- (b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by Sproule in the North Peace Reserve Report were Sproule's forecasts as at December 31, 2009, which were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

FORECAST PRICES AND COSTS

Year	OIL			NATURAL GAS			Edmonton Pentanes Plus (\$Cdn/Bbl)	INFLATION RATES ⁽¹⁾ %/Year	EXCHANGE RATE ⁽²⁾ (\$US/\$Cdn)
	WTI Cushing Oklahoma (\$US/Bbl)	Edmonton Par Price 40° API (\$Cdn/Bbl)	Cromer Medium 29.3° API (\$Cdn/Bbl)	AECO Gas Price (\$Cdn/MMBtu)	Edmonton Propane (\$Cdn/Bbl)	Edmonton Butane (\$Cdn/Bbl)			
Forecast									
2010	79.17	84.25	80.04	5.36	52.74	59.65	86.28	2.0	0.92
2011	84.46	89.99	84.59	6.21	56.33	63.72	92.16	2.0	0.92
2012	86.89	92.61	85.20	6.44	57.97	65.57	94.84	2.0	0.92
2013	90.20	96.19	87.53	7.23	60.21	68.11	98.51	2.0	0.92
2014	92.01	98.13	88.32	7.98	61.43	69.48	100.50	2.0	0.92
2015	93.85	100.11	90.10	8.16	62.67	70.89	102.53	2.0	0.92
2016	95.72	102.13	91.92	8.34	63.94	72.32	104.60	2.0	0.92
2017	97.64	104.19	93.77	8.52	65.23	73.78	106.71	2.0	0.92
2018	99.59	106.30	95.67	8.71	66.54	75.27	108.86	2.0	0.92
2019	101.58	108.44	97.60	8.90	67.89	76.79	111.06	2.0	0.92
Thereafter	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	2.0	0.92

Notes:

- (1) Inflation rates for forecasting prices and costs.
- (2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by us for the year ended December 31, 2009, were nil for natural gas, nil for crude oil and \$44/Bbl for bitumen.

Estimated future abandonment costs related to a property have been taken into account by Sproule in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs. No allowance was made, however, for reclamation of wellsites or the abandonment and reclamation of any facilities.

The forecast price and cost assumptions assume the continuance of current laws and regulations.

The extent and character of all factual data supplied to Sproule were accepted by Sproule as represented. No field inspection was conducted.

The Alberta government has announced, but not yet enacted, provisions that allow for transitional royalties ("**Transitional Royalties**") to the New Royalty Framework ("**NRF**") for certain elected wells. For the purposes of the Sproule Report, Alberta Crown Royalties have been determined in accordance with the NRF. The impact of the optional Transitional Royalties was considered in our plans for future drilling in Alberta. North Peace was assumed to opt for Transitional Royalties where justified by a comparison of economics under Transitional Royalties and the NRF.

On March 3, 2009 the Alberta government announced a three point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Reserves and net present values reflected in the above tables do not reflect the potential effect of this new program and no sensitivities were provided by Sproule as to the potential impact of same.

Reconciliation of Changes in Reserves

The following table sets out the reconciliation of our gross reserves as at December 31, 2008 compared to December 31, 2009 based on forecast prices and costs by principal product type:

FACTORS	LIGHT AND MEDIUM OIL			NATURAL GAS SOLUTION			HEAVY OIL		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)
December 31, 2008	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	-	-	-	236	120	356	52.6	26.7	79.3
Technical Revisions	-	-	-	-	-	-	-	-	-
Discoveries	17.1	14.9	32.0	4	2	6	4.5	1.8	6.3
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-0.1	-	-0.1
December 31, 2009	<u>17.1</u>	<u>14.9</u>	<u>32.0</u>	<u>241</u>	<u>121</u>	<u>362</u>	<u>57</u>	<u>28.4</u>	<u>85.4</u>

Note:

- (1) Gross Reserves in the tables above are North Peace's interest share before deduction of royalties and without including any royalty interests of North Peace.
- (2) Numbers may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to North Peace's assets for the years ended December 31, 2009, 2008 and 2007 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

	Light and Medium Oil (Mbbbl)		Conventional Natural Gas (MMcf)		Heavy Oil (Mbbbl)	
	First Attributed	Booked at Year-end	First Attributed	Booked at Year-end	First Attributed	Booked at Year-end
Prior	0.0	0.0	0.0	0.0	0.0	0.0
2007	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.0	0.0	0.0	0.0	0.0	0.0
2009	0.0	0.0	120.4	120.4	26.7	26.7

Probable Undeveloped Reserves

	Light and Medium Oil (Mbbbl)		Conventional Natural Gas (MMcf)		Heavy Oil (Mbbbl)	
	First Attributed	Booked at Year-end	First Attributed	Booked at Year-end	First Attributed	Booked at Year-end
Prior	0.0	0.0	0.0	0.0	0.0	0.0
2007	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.0	0.0	0.0	0.0	0.0	0.0
2009	0.0	0.0	60.2	60.2	13.4	13.4

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. The majority of undeveloped reserves are scheduled to be developed within the next two years. North Peace has areas where multiple zones have been assigned reserves in a well. Once the producing zones are depleted, capital will be spent recompleting the well in another zone. Some of these expenditures are planned to occur in 2010 and beyond, the timing dictated by the predicted reserve life for the

currently producing zones. A number of factors that could result in delayed or cancelled development are as follows:

- changing economic conditions (due to pricing, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies (such as water breakthrough, accelerated depletion));
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

While we do not anticipate any significant economic factors or significant uncertainties will affect any particular components of the reserves data, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control (see "*Risk Factors*").

Future Development Costs

The following table sets forth development costs deducted in the estimation of North Peace's future net revenue attributable to the reserve categories noted below (\$000s):

Year	Forecast Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves
2010	832	832
2011	-	-
2012	-	-
2013	-	-
2014	-	-
Thereafter	-	-
Total Undiscounted	832	832

North Peace expects that the capital listed in the preceding table will be funded through three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favourable terms.

Other Oil and Gas Information

Oil and Gas Wells

The oil and gas properties of North Peace are set forth under "*Principal Properties*" herein. The following table sets forth the number and status of wells in which North Peace had a working interest as at December 31, 2009.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	4	3	1	0.6	-	-	-	-
Total	4	3	1	0.6	-	-	-	-

Land Holding Including Properties with no Attributed Reserves

The following table sets out North Peace's developed and undeveloped land holdings as at December 31, 2009.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	960	656	90,560	88,368	91,520	89,024
Total	960	656	90,560	88,368	91,520	89,024

North Peace expects that rights to explore, develop and/or exploit 384 net acres of its undeveloped land holdings may expire by December 31, 2010. North Peace plans to drill or submit applications to continue selected portions of the above acreage.

Additional Information Concerning Abandonment and Reclamation Costs

Well abandonment costs on existing and future reserve wells have been included in the economic forecasts contained in the North Peace Reserves Report, while well abandonment costs on non-reserves wells, pipelines, production facilities and site reclamation have been excluded.

Abandonment costs are estimated on an area by area basis by Sproule. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. North Peace currently has 3 net wells for which it expects to incur abandonment and reclamation costs.

The total abandonment cost in respect of proved reserves using forecast prices is \$115,000 (undiscounted) and \$46,000 (discounted at 10%). 100% of such amounts were deducted as abandonment costs in estimating our future net revenue as disclosed above.

The following table sets forth the abandonment costs deducted in the estimation of our future net revenue:

<u>Forecast Prices and Costs (Total Proved) (\$000s)</u>	
Year	Abandonment Costs (Undiscounted)
2010	-
2011	-
2012	-
Thereafter	115
Total Undiscounted	115
Total Discounted @ 10%	46

Tax Horizon

North Peace was not required to pay any cash income taxes for the period ended December 31, 2009. Based on current estimates of North Peace's future taxable income and levels of tax deductible expenditures, management believes that North Peace will not be required to pay cash income taxes until 2011 or later.

Capital Expenditures

The following table summarizes capital expenditures related to our assets and activities for the year ended December 31, 2009:

	\$000s
Property acquisition costs	
proved properties	125
undeveloped properties	248
Development and facility costs	10,219
Undeveloped properties	-
Exploration costs	3,208
Total	10,780

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which North Peace participated in the year ended December 31, 2009:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Natural Gas	-	-	-	-
Light and Medium oil	1	0.6	-	-
Heavy Oil	1	0.5	1	0.5
Service	10	10.0	-	-
Dry	2	2.0	-	-
Total	15	13.6	-	-

Production Estimates

The following tables sets out the volume of our production estimated for the year ended December 31, 2010, which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "*Disclosure of Reserves Data*" above. **[NTD: Please provide 2010 production estimate]**

Reserves Category	Light and Medium Oil		Natural Gas		Heavy Oil		Total Oil Equivalent	
	Gross (Bbl/d)	Net (Bbl/d)	Gross (Mcf/d)	Net (Mcf/d)	Gross (Bbl/d)	Net (Bbl/d)	Gross (Boe/d)	Net (Boe/d)
PROVED								
Beaton	-	-	93	85	23	21	38	35
Valhalla	17	16	-	-	-	-	17	16
TOTAL PROVED	17	16	93	85	23	21	55	51
PROVED PLUS PROBABLE								
Beaton	-	-	99	90	24	23	41	38
Valhalla	19	18	-	-	-	-	19	18
TOTAL PROVED PLUS PROBABLE	19	18	99	90	24	23	60	56

Notes:

- (1) No other individual property accounted for 20% or more of North Peace's estimated 2009 production disclosed.
- (2) Numbers may not add due to rounding.

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback associated with North Peace's assets for the periods indicated below:

	2009			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production⁽¹⁾				
Light and Medium Crude Oil (Bbls/d)	-	-	-	-
Conventional Gas (Mcf/d)	-	-	-	-
Heavy Oil (Bbls/d)	52	91	62	-
Combined (boe/d)	52	91	62	-
Average Price Received				
Light and Medium Crude Oil (\$/Bbl)	-	-	-	-
Conventional Gas (\$/Mcf)	-	-	-	-
Heavy Oil (\$/Bbls)	48.41	47.13	53.33	-
Combined (\$/BOE)	48.41	47.13	53.33	-
Royalties Paid				
Light and Medium Crude Oil (\$/Bbls)	-	-	-	-
Conventional Gas (\$/Mcf)	-	-	-	-
Heavy Oil (\$/Bbls)	0.54	1.65	1.49	-
Combined (\$/BOE)	0.54	1.65	1.49	-
Transportation costs				
Light and Medium Crude Oil (\$/Bbls)	-	-	-	-
Conventional Gas (\$/Mcf)	-	-	-	-
Heavy Oil (\$/Bbls)	5.06	1.84	3.07	-
Combined (\$/BOE)	5.06	1.84	3.07	-
Operating Expenses				
Light and Medium Crude Oil (\$/Bbls)	-	-	-	-
Conventional Gas (\$/Mcf)	-	-	-	-
Heavy Oil (\$/Bbls)	181.98	81.73	157.45	-
Combined (\$/BOE)	181.98	81.73	157.45	-
Netback Received (\$/BOE)⁽²⁾				
Light and Medium Crude Oil (\$/Bbls)	-	-	-	-
Conventional Gas (\$/Mcf)	-	-	-	-
Heavy Oil (\$/Bbls)	(108.69)	(38.46)	(104.46)	-
Combined (\$/BOE)	(108.69)	(38.46)	(104.46)	-

Notes:

- (1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties, transportation costs and operating costs from revenues.

The following table indicates North Peace's average daily production from its important fields for the year ended December 31, 2009:

	Heavy Oil (bbl/d)	Total Oil Equivalent (boe/d)
Red Earth	44	44
Beaton	-	-
Valhalla	-	-
Total	44	44

For the year ended December 31, 2009, all of North Peace's gross revenue was derived from Heavy Oil.

DIVIDEND POLICY

North Peace has not paid any dividends on the outstanding Common Shares. The Board of Directors of North Peace will determine the actual timing, payment and amount of dividends, if any, that may be paid by North Peace from time to time based upon, among other things, the cash flow, results of operations and financial conditions of North Peace, the needs for funds to finance ongoing operations and other business considerations as the Board of Directors of North Peace considers relevant.

DESCRIPTION OF CAPITAL STRUCTURE

The Corporation is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series. The following is a description of the rights, privileges, restrictions and conditions attaching to the share capital of the Corporation.

Common Shares

The Corporation has an unlimited number of Common Shares authorized of which 76,179,800 are presently issued and outstanding. The holders of Common Shares are entitled to: dividends if, as and when declared by the board of directors; to one vote per share at any meeting of the shareholders of the Corporation; and upon liquidation to receive, all assets of the Corporation as are distributable to the holders of shares.

Preferred Shares

North Peace is authorized to issue an unlimited number of preferred shares issuable in series, each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the board of directors of North Peace prior to the issuance thereof. With respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding up of North Peace, whether voluntary or involuntary, the preferred shares are entitled to preference over the Common Shares and any other shares ranking junior to the preferred shares from time to time and may also be given such other preferences over the Common Shares and any other shares ranking junior to the preferred shares as may be determined at the time of creation of such series. At the date hereof, no series of preferred shares has been created.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSXV under the symbols "NPE".

The following sets forth the price range and trading volume of the Common Shares on (as reported by such exchange) for the periods indicated.

Common Shares				
Price Range				
	High (\$/share)	Low (\$/share)	Close (\$/share)	Volume (000s)
2009				
January	0.35	0.25	0.28	1,220
February	0.35	0.25	0.30	2,111
March	0.65	0.26	0.60	1,500
April	0.60	0.44	0.50	1,409
May	0.90	0.47	0.66	3,397
June	0.78	0.50	0.78	3,373
July	0.77	0.50	0.59	710
August	0.60	0.45	0.46	878
September	0.55	0.45	0.50	2,365
October	0.50	0.42	0.43	1,669
November	0.42	0.30	0.31	2,241
December	0.34	0.24	0.28	11,197
2010				
January	0.38	0.28	0.28	14,052
February	0.29	0.18	0.20	10,704
March	0.20	0.14	0.16	4,386
April (1-19)	0.31	0.16	0.25	6,557

DIRECTORS AND OFFICERS

The names, municipalities of residence, positions with the Corporation, and principal occupation of the directors and officers of the Corporation are set out below and in the case of directors, the period each has served as a director of the Corporation.

Name and Municipality of Residence	Office Held	Number and Percentage of Securities of Resulting Issuer	Director/ Officer Since	Principal Occupation
Louis Dufresne Calgary, Alberta ⁽²⁾	President and Chief Executive Officer and a Director	1,732,000 (2.27%) ⁽⁴⁾	2003	President and Chief Executive Officer of the Corporation since 2007; prior thereto independent businessman involved in a number of private energy related businesses. Prior to July, 2001, Mr. Dufresne was the senior vice-president and a director of Direct Energy and held various management positions with Direct Energy from 1992 through 2001. Before joining Direct Energy, Mr. Dufresne held various engineering and other positions with Gulf Canada Resources from 1983 to 1992. Mr. Dufresne obtained a Bachelor of Science (Mechanical Engineering) degree from the University of Waterloo in 1983 and received his designation as a Professional Engineer in 1985.
James Glessing Calgary, Alberta	Vice-President, Finance and Chief Financial Officer	73,600 (0.10%) ⁽⁵⁾	2007	VP Finance and Chief Financial Officer of the Corporation since 2007; prior thereto, Controller at Black Rock Ventures.
Don Garner ⁽¹⁾⁽²⁾⁽³⁾ Calgary, Alberta	Director	1,500,000 (1.97%) ⁽⁶⁾	2007	Professional engineer and oil and gas professional with twenty-nine years experience in the upstream petroleum industry; former Chief Executive Officer and advisor to TAQA North Ltd. who acquired PrimeWest Energy Trust where Mr. Garner was the President and Chief Executive Officer since 2003; prior thereto, President and Chief Operating Officer of Northstar Energy Corporation and prior thereto spent 19 years at Imperial Oil Limited in various capacities.
Bill Maslechko ⁽²⁾⁽³⁾ Calgary, Alberta	Director	894,500 (1.17%) ⁽⁷⁾	2003	Partner, Burnet, Duckworth & Palmer LLP since 1994.
Ian Robertson ⁽¹⁾⁽²⁾ Oakville, Ontario	Director	859,500 (0.87%) ⁽⁸⁾	2003	Chief Executive Officer of Algonquin Power & Utilities Corp., a TSX listed power and utilities company. Prior to 2009, a Senior Manager with the TSX listed Algonquin Power Income Fund since its formation in 1997. From 1988 through 1997, a principal with Algonquin Power Corporation Inc., a private developer of independent power projects in Canada and the US.

Name and Municipality of Residence	Office Held	Number and Percentage of Securities of Resulting Issuer	Director/ Officer Since	Principal Occupation
Jacob Roorda ^{(1) (2) (3)} Calgary, Alberta	Director	1,357,450 (1.78%) ⁽⁹⁾	2007	President, CEO and director of Canoe Financial Corp which is the manager of the Enervest group of funds, including TSX listed EnerVest Diversified Income Trust and EnerVest Energy and Oil Sands Total Return Trust, and private EnerVest Natural Resource Fund Ltd. and the EnerVest Flow-Through Share Limited Partnerships, all effective September 25, 2008; Previously Vice-President of Harvest Energy Trust, a publicly traded integrated oil and natural gas royalty trust based in Calgary. Mr. Roorda was one of the founding group and President of Harvest Energy from July 2002 until February 2006, when it merged with another royalty trust.
Harley Rea Calgary, AB	VP Engineering	114,333 (0.15%) ⁽¹⁰⁾	2007	Vice President, Engineering of the Corporation since August 2007; prior thereto, Project Manager, Burlington Resources/Conoco Phillips.

Notes:

- (1) Member of the Audit Committee.
- (2) Member of the Corporate Governance Committee.
- (3) Member of the Reserves Committee.
- (4) Mr. Dufresne also holds incentive stock options to purchase 425,000 Common Shares at \$1.00 per share expiring November, 2011, options to purchase 350,000 Common Shares at \$1.50 per share expiring July, 2013, options to purchase 125,000 Common Shares at \$2.62 expiring June, 2012, options to purchase 525,000 Common Shares at 0.55 expiring June, 2014 and 1,700,000 performance warrants exercisable at a price of \$0.50 per share.
- (5) Mr. Glessing also holds incentive stock options to purchase 175,000 Common Shares at \$1.00 per share expiring March, 2012 options to purchase 125,000 Common Shares at \$2.62 per share expiring June 2012, options to purchase 300,000 Common Shares at \$1.50 per share expiring July 2013, options to purchase 525,000 Common Shares at \$0.55 per share expiring June 2014 and 200,000 performance warrants exercisable at a price of \$0.50 per share.
- (6) Mr. Garner also holds incentive stock options to purchase 93,750 Common Shares at \$1.00 per share expiring November, 2011, options to purchase 25,000 Common Shares at \$2.62 per share expiring June, 2012, options to purchase 70,000 Common Shares at \$1.50 per share expiring July, 2013, options to purchase 125,000 Common Shares at \$0.55 per share expiring June 2014 and 25,000 performance warrants exercisable at a price of \$0.50 per share.
- (7) Mr. Maslechko also holds incentive stock options to purchase 93,750 Common Shares at \$1.00 per share expiring November, 2011, options to purchase 25,000 Common Shares at \$2.62 per share expiring June, 2012, options to purchase 70,000 Common Shares at \$1.50 per share expiring July, 2013, options to purchase 125,000 Common Shares at \$0.55 per share expiring June 2014 and 25,000 performance warrants exercisable at a price of \$0.50 per share.
- (8) Mr. Robertson also holds incentive stock options to purchase 93,750 Common Shares at \$1.00 per share expiring November, 2011, options to purchase 25,000 Common Shares at \$2.62 per share expiring June, 2012, options to purchase 70,000 Common Shares at \$1.50 per share expiring July, 2013, options to purchase 125,000 Common Shares at \$0.55 per share expiring June 2014 and 25,000 performance warrants exercisable at a price of \$0.50 per share.
- (9) Mr. Roorda also holds incentive stock options to purchase 93,750 Common Shares at \$1.00 per share expiring November, 2011, options to purchase 25,000 Common Shares at \$2.62 per share expiring June, 2012, options to purchase 70,000 Common Shares at \$1.50 per share expiring July, 2013, options to purchase 125,000 Common Shares at \$0.55 per share expiring June 2014 and 25,000 performance warrants exercisable at a price of \$0.50 per share.
- (10) Mr. Rea also holds incentive stock options to purchase 400,000 Common Shares at \$1.82 per share expiring August, 2012 options to purchase 300,000 Common Shares at \$1.50 per share expiring July, 2013, options to purchase 525,000 Common Shares at \$0.55 per share expiring June, 2014 and 100,000 performance warrants exercisable at a price of \$0.50 per share.

Cease-Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as set forth below, no director is as at the date hereof, or has been, within 10 years of the date hereof, a director or executive officer of any company, including the Corporation, that while that person was acting in that capacity:

- (a) was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days;
- (b) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order, or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days,
- (c) or within a year of that person ceasing to act in that 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
- (d) has, within the 10 years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceeding, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or shareholder.

In addition, no director has had any penalties or sanctions imposed against him or entered into any settlement agreement in respect of any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority, including a settlement agreement with a securities regulatory authority, or any other penalties or sanctions imposed by a court or regulatory body.

Mr. Roorda was a director of TXCO Resources Ltd., a NASDAQ listed public company until February 11, 2010. On April 18, 2009, TXCO Resources Ltd. filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code in the United States Bankruptcy Court for the Western District of Texas. The TXCO Board obtained approval of a plan of reorganization which paid all creditors in full and which projects a recovery for common shareholders.

The term of office of each director expires at the next annual meeting of shareholders of the Corporation.

As at April 20, 2010, the directors and officers of North Peace and their associates, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 6,331,383 Common Shares or approximately 8.31% of the issued and outstanding Common Shares.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the board of directors is attached hereto as Schedule "C". Composition of the Audit and Reserves Committee

The members of the Audit Committee are Don Garner, Jacob Roorda and Ian Robertson. The members of the Audit Committee are independent (in accordance with National Instrument 52-110) and are financially literate. The following is a description of the education and experience of each member of the Audit Committee.

Pre-Approval of Policies and Procedures

The Audit Committee has adopted a policy to review and pre-approve any non-audit services to be provided to North Peace by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by the Corporation's external auditor in each of the last two fiscal years for audit services were \$61,000 in 2009 and \$51,000 in 2008.

Audit-Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance and related services by the Corporation's external auditor that are reasonably related to the performance of the audit or review of the Corporation's financial statements that are not reported under "Audit Fees" above were \$7,500 in 2009 and \$7,500 in 2008. Fees were billed for audit related services including the audit of financial statements for properties acquired, review of pro-forma financial statements, services rendered in connection with financings, and meetings and discussions related to the Corporation's internal control documentation.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the Corporation's external auditor for tax compliance, tax advice and tax planning were \$12,525 in 2009 and \$2,850 in 2008. Fees were billed for services provided in the preparation of corporate tax returns.

All Other Fees

No fees were billed in either of the last two fiscal years for products and services provided by the Corporation's auditors other than services reported above.

CONFLICTS OF INTEREST

The directors or officers of the Corporation may also be directors or officers of other oil and gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with the Corporation. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

HUMAN RESOURCES

As at December 31, 2009, North Peace employed 5 full-time employees located in the head office 3 full time employees in the field, and 5 part-time consultants. North Peace intends to add additional professional and administrative staff as the need arises.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are KPMG LLP, Chartered Accountants, Suite 2700, 205 – 5th Avenue SW, Calgary AB T2P 4B9.

CIBC Mellon Trust Company, at its principal office in Calgary, Alberta, is the transfer agent and registrar of the Common Shares.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of the Corporation, there are no legal proceedings to which the Corporation is a party or of which any of their respective properties is the subject matter nor are there any such proceedings known to the Corporation to be contemplated.

During the year ended December 31, 2009 there were: (i) no penalties or sanctions imposed against the Corporation or by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, and (iii) no settlement agreements the Corporation entered into with a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of the Corporation, of any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10% of the outstanding voting securities of the Corporation, or any other Informed Person (as defined in National Instrument 51-102) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial that has materially affected or would materially affect the Corporation or any of its subsidiaries except as follows.

Certain directors and officers of North Peace have participated in private placements and public offerings by North Peace on the same basis as other arm's length subscribers to such offerings.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Corporation has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than Sproule, the Corporation's independent engineering evaluators and KPMG LLP, the Corporation's auditors. None of the principals of Sproule had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of the Corporation's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. KPMG LLP are independent in accordance with the auditor's rules of professional conduct of the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada and Alberta, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through the liquid market established at the Alberta "NIT" hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m³/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

As a result of pipeline expansions over the past several years, there is ample pipeline capacity to accommodate current production levels of oil and natural gas in western Canada and pipeline capacity does not generally limit the ability to produce and market such production.

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain voluntary measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, that any prohibition in any circumstances in which any other form of quantitative restriction is applied is prohibited, and in the case of import price requirements, that such requirements do not apply with respect to enforcement of countervailing and anti dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes, minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty like interests are, from time to time, carved out of the working interest owner's interest through non public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of \$3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors; specifically, the maximum royalty rates for conventional oil and natural gas production will be decreased effective for the January 2011 production month and certain temporary incentive programs currently in place will be made permanent.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the NRF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF range from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps are set at \$120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 40%.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF range from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps are set at \$17.75/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 36%.

Oil sands projects are also subject to the NRF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil: rates are 1% when the market price of oil is less than or equal to \$55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at \$120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above \$55 up to 40% when oil is priced at \$120 or higher. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF.

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "IETP"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP is backed by a \$200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a \$1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to \$3,750 per metre.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers will only be able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that have already elected to adopt the transitional royalty rates as of that date will be permitted to switch to Alberta's conventional royalty structure. On December 31, 2013, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a \$200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 barrels of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, Alberta currently maintains a royalty reduction program for low productivity oil and oil sands wells, a royalty adjustment program for deep marginal gas wells and a royalty exemption for re-entry wells, among others.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides, for the first time in western Canada, for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, approvals and authorizations in order for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its greenhouse gas emissions levels to 6% below 1990 "business as usual" levels by 2012.

In anticipation of the expiry of the Kyoto Protocol in 2012, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark from December 6 to 18, 2009 (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Although certain countries, including Canada, have committed to reducing their emissions individually or jointly by at least 80% by 2050, the Copenhagen Accord does not establish binding GHG emissions reduction targets. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016.

In response to the Copenhagen Accord, the Government of Canada has recently indicated that it will seek to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which are discussed below.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both greenhouse gases and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives the Government of Canada have recently indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. The approach of the United States is expected to include an absolute cap on emissions combined with allowances to be used for compliance that may be partially auctioned off to regulated entities. It is also unclear whether the approach adopted by the United States will provide for the payment into a technology fund as a compliance mechanism, as is currently permitted in Alberta and by the Updated Action Plan. As a result, many provisions of the Updated Action Plan, described below, are expected to be significantly modified.

The stated goal of the Updated Action Plan, as currently drafted, is to reduce greenhouse gas emissions to 20% below 2006 levels by 2020 and 60-70% by 2050. As noted above, the goal has now been modified by the Government of Canada. The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets applied to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities,

upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO₂ equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO₂ equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors govern by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at \$15 tonnes per CO₂ equivalent for the 2010-12 period, rising to \$20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on July 1, 2007, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to comply with the CCEMA. Similarly to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Existing Facilities" and "New Facilities". Existing Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2008 or that have completed 8 or more years of commercial operation. Existing Facilities were required to reduce their emissions intensity by March 31, 2008 by 12% from a baseline established by their average emissions intensity between 2003 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation subsequent to December 31, 2008, have completed less than 8 years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are also required to reduce their emissions intensity by 12% but this target is based on the emissions intensity of the facility in its third year of commercial operation and does not apply during the first 3 years of operation of the New Facility. Unlike the Updated Action

Plan, the CCEMA does not contain any provision for continuous annual improvements beyond the 12% emissions intensity required.

The CCEMA contains similar compliance mechanisms as the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "Fund") at a rate of \$15 per tonne of CO₂ equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

To the knowledge of the Corporation, there is no ownership or working interests in facilities which meet or are expected to meet the emissions threshold.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations

or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

In-situ extraction may not be economic or sustainable.

In-situ developments are based on expectations of successful exploration drilling results. While the Corporation's resource in composite is significant, lease specific resource qualities may vary greatly and can only be confirmed through exploration and full delineation. Only after this drilling is complete and feasibility studies of the appropriate technology to apply to the resource are done can the potential of the resource be quantified.

The recovery of bitumen and heavy oil using the CSS process is subject to a number of risks and uncertainties, many of which are outside of North Peace's control. Current CSS technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas or other fuels in the production of steam which is used in the recovery process. The amount of steam required in the production process can also vary and impact costs. The quality and performance of the reservoir can also impact the timing and levels of production using this technology. The application of this technology at Red Earth is new, and accordingly in the absence of long-term operating history there can be no assurances with respect to the sustainability of CSS operations. Although CSS technology has been tested in other oil sands operations, there can be no assurance that CSS utilization on the Red Earth Project will achieve similar results as in other situations or produce bitumen and heavy oil at the expected levels or costs, on schedule or at all.

Severe weather conditions can cause reduced production and in some situations result in higher costs. CSS bitumen recovery facilities and development and expansion of production can entail significant capital outlays. Equipment failures could result in damage to North Peace's facilities or wells and liability to third parties against which North Peace may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons.

The performance of North Peace's CSS facilities may differ from its expectations. The variances from these expectations may include, without limitation, the ability to operate at the expected level of throughput or production and the reliability or availability of the facilities. Additionally, the operating costs of oil sands projects are significant components of the cost of production of the bitumen. The operating costs of the North Peace's oil sands projects may vary considerably during the operating period. If the facilities do not perform to North Peace's expectations or as required by regulatory approvals, North Peace may be required to invest additional capital to correct deficiencies or North Peace may not be able to produce the expected level of production. If these expectations are not met or operating costs are higher than anticipated, North Peace's revenue, cash flow and earnings could be reduced

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of

foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Hedging

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various

actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. Although economic conditions improved towards the latter portion of 2009, these factors have negatively impacted company valuations and may impact the performance of the global economy going forward.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

Uncertainties Associated with Estimating Resource Volumes

Other than Probable and Possible Reserves associated with certain portions of the Peace River arch area of Alberta, the Company has not established any reserves, although it has identified Contingent Resources. Sproule has completed a geological evaluation of the Company's properties effective as of December 31, 2009. See "Bitumen Resources – Red Earth Project". There are numerous uncertainties inherent in estimating the quantities of reserves and resources attributable to the Red Earth Project, and the Company's other assets, including many factors beyond the Company's control, and no assurance can be given that the indicated level of reserves and resources will be realized. In general, estimates of recoverable reserves and resources are based upon a number of factors and assumptions made as of the date on which the reserves and resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves and resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen and the classification of such reserves and resources based on risk of recovery prepared by different engineers or by the same engineers at different times may vary substantially.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves and resources, rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves and resources based upon production history will result in variations, which may be material, in the estimated reserves and resources. Reserves and resource estimates may require revision based on actual production experience. Such figures have been determined based upon assumed oil prices and operating costs. Market fluctuations of oil prices may render uneconomic the recovery of certain grades of bitumen. Moreover, short term factors relating to oil sands reserves and resources may impair the profitability of the Company's projects in any particular period.

There is no certainty that the Red Earth area will produce any portion of the volumes currently classified by Sproule as "Bitumen Resources" or "Contingent Resources".

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the

economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;

- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully

insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geo Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation will not have insurance to protect against the risk from terrorism.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non core assets, certain non core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so called "greenhouse gases". Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. Pursuant to the resulting Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol, the Government of Canada revised its emissions reduction targets slightly. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with Alberta's greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Act* and the *Specified Gas Emitters Regulation*. The Corporation may also be required to comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits required by the Kyoto

Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Climate Change Regulation".

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

Management of Growth

The Corporation may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dividends

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations as the board of directors of the Corporation considers relevant.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Conflicts of Interest

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Conflicts of Interest".

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's information circular for the Corporation's most recent annual meeting of security holders that involved the election of directors. Additional financial information is contained in the Corporation's consolidated financial statements and the related management's discussion and analysis for the Corporation's most recently completed financial year.

SCHEDULE "A"
FORM 51-101F3
REPORT OF
MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE

Management of North Peace Energy Corp. (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Corporation has

- (a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluators;
- (b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

- (d) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (e) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and
- (f) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "Louis Dufresne"
Louis Dufresne, Chief Executive Officer, President

(signed) "Don Garner"
Don Garner, Director

(signed) "James Glessing"
James Glessing, Chief Financial Officer

(signed) "Bill Maslechko"
Bill Maslechko, Director

Dated: April 20, 2010

SCHEDULE "B"
FORM 51 101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

To the board of directors of North Peace Energy Corp. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2009, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income tax, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
			M\$	M\$	M\$	M\$
Sproule Associates Limited	Evaluation of the P&NG Reserves of North Peace Energy Corp. As of December 31, 2009 and prepared January to February, 2010	Canada	Nil-	3,711	Nil	3,711

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

EXECUTED as to our report referred to above.

Sproule Associates Limited, Calgary, Alberta, dated February 3, 2010.

Sproule Associates Limited

(signed) "Robert Warholm, P. Eng."

Robert Warholm, P. Eng

SCHEDULE "C"
NORTH PEACE ENERGY CORP.
AUDIT COMMITTEE CHARTER

Introduction

North Peace Energy Corp. (the "**Corporation**") is an Alberta based early stage oil sands company. The Board of Directors of the Corporation (the "**Board**") has the responsibility for the overall stewardship of the conduct of the business of the Corporation and its subsidiaries and the activities of management of the Corporation, which is responsible for the day-to-day conduct of the business.

Purpose

The overall purpose of the Audit Committee (the "**Committee**") is to ensure that the Corporation's management has designed and implemented an effective system of internal financial controls and disclosure controls and procedures, to review and report on the integrity of the consolidated financial statements of the Corporation and to review the Corporation's compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and disclosure of material facts.

Composition, Procedures And Organization

The Committee shall consist of at least three members of the Board, all of whom shall be "independent", as that term is defined in Sections 1.4 and 1.5 of Multilateral Instrument 52-110 Audit Committees.

All of the members of the Committee shall be "financially literate" (i.e. able to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of those of the Corporation and that can be reasonably expected to be raised by the Corporation's financial statements).

The Committee composition, including the qualifications of its members, shall comply with the applicable requirements of stock exchanges on which the Corporation lists its securities and of securities regulatory authorities, as such requirements may be amended from time to time.

The Board shall appoint the members of the Committee. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee.

Unless the Board shall have appointed a chair of the Committee, the members of the Committee shall elect a chair from among their members.

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.

The Committee shall have access to such officers and employees of the Corporation and to the Corporation's external auditors, and to such information respecting the Corporation, as it considers necessary or advisable in order to perform its duties and responsibilities.

Meetings of the Committee shall be conducted as follows:

the Committee shall meet at least four times annually at such times and at such locations as may be requested by the chair of the Committee. The external auditors or any member of the Committee may request a meeting of the Committee;

the external auditors shall receive notice of and have the right to attend all meetings of the Committee; and

the following management representatives shall be invited to attend all meetings, except executive sessions and private sessions with the external auditors:

President and Chief Executive Officer
Chief Financial Officer

other management representatives shall be invited to attend as necessary.

The external auditors shall report directly to the Committee and the external auditors shall have a direct line of communication to the Committee through its chair and may bypass management if deemed necessary. The Committee, through its chair, may contact directly any employee of the Corporation as it deems necessary, and any employee may bring before the Committee any matter involving questionable, illegal or improper financial practices or transactions.

The Committee may retain, at the Corporation's expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties and may set and pay the compensation for any advisor engaged. The Committee will notify the Board whenever independent consultants are engaged.

Handling of Complaints

The Committee shall maintain procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters, and the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters (a "**Whistleblower Policy**").

Annual Review

The Committee will review and assess the adequacy of its mandate annually, report to the Board of Directors thereon and recommend any proposed changes to the Board of Directors for approval. The Committee will also perform an annual evaluation of the performance of the Committee and will report the results of the evaluation to the Corporation's Board of Directors.

Role and Responsibilities

1. The responsibilities of the Committee will be as follows:
 - to assist the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and its approval of the Corporation's annual and quarterly consolidated financial statements and management's discussion and analysis;
 - to establish and maintain a direct line of communication with the Corporation's external auditors and assess their performance;
 - to assist the Board in the discharge of its responsibilities relating to oversight of the Corporation's internal, financial and disclosure controls and procedures;
 - to periodically review the audit and non-audit services pre-approval policy and recommend to the Board any changes which the Committee deems appropriate;

- to periodically consider whether there is a need to create an internal audit department;
 - to receive and review complaints received pursuant to the Corporation's Whistleblower Policy and oversee and provide direction on the investigation and resolution of such concerns and to periodically review such policy and recommend to the Board changes which the Committee may deem appropriate;
 - to report periodically to the Board on the fulfillment of its duties and responsibilities;
 - to identify and monitor the management of the principal risks that could impact the financial reporting of the Corporation;
 - to ensure that it satisfies those responsibilities set out in Part 2 of MI 52-110 and provisions contained within the Companion Policy to 52-110; and
 - review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation.
2. The duties and responsibilities of the Committee as they relate to the external auditors shall be as follows:
- to be directly responsible for overseeing the work of the external auditors engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management and the external auditors regarding financial reporting;
 - to recommend to the Board a firm of external auditors to be nominated for appointment by the shareholders of the Corporation, and to monitor and verify the independence of such external auditors;
 - to review and approve the fee, scope and timing of the audit and other audit related and non-audit services rendered by the external auditors;
 - review the audit plan of the external auditors prior to the commencement of the audit;
 - to review with the external auditors, upon completion of their audit:
 - contents of their report;
 - scope and quality of the audit work performed;
 - adequacy of the Corporation's financial and auditing personnel;
 - co-operation received from the Corporation's personnel during the audit;
 - internal resources used;
 - significant transactions outside of the normal business of the Corporation;
 - significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems; and

- the non-audit services provided by the external auditors, as pre-approved pursuant to the audit and non-audit services pre-approval policy;
 - to discuss with the external auditors the quality and not just the acceptability of the Corporation's accounting principles;
 - to review any unresolved issues between management and the external auditors that could affect the financial reporting or internal controls of the Corporation;
 - to implement structures and procedures to ensure that the Committee meets the external auditors on a regular basis in the absence of management; and
 - to receive a written statement not less than annually from the external auditor describing in detail all relationships between the auditor and the Corporation that may affect the objectivity and independence of the auditor. The Committee shall review annually with the Board of Directors the independence of the external auditors and either confirm to the Board of Directors that the external auditors are independent or recommend that the Board of Directors take appropriate action to satisfy itself of the external auditor's independence.
 - The duties and responsibilities of the Committee as they relate to the internal control procedures of the Corporation are to:
 - review the appropriateness and effectiveness of the Corporation's policies and business practices which impact on the financial integrity of the Corporation, including those relating to insurance, accounting, information services and systems and financial controls, management reporting and risk management;
 - review compliance under the Corporation's code of business conduct adopted from time to time with those matters addressed in the code which affect the financial integrity of the Corporation and to periodically review the code and recommend to the Board changes which the Committee may deem appropriate; and
 - periodically review the Corporation's financial and auditing procedures and the extent to which recommendations made by the internal accounting staff or by the external auditors have been implemented.
3. The Committee is also charged with the responsibility to:
- review and recommend to the Board for its approval, the Corporation's annual financial statements, management's discussion and analysis, annual information form and annual earnings press releases before the Corporation publicly discloses this information;
 - review and approve the Corporation's interim financial statements, interim management's discussion and analysis including the impact of unusual items and changes in accounting principles and estimates and report to the Board with respect thereto and interim earnings press releases before the Corporation publicly discloses this information;
 - review and approve the financial sections of:
 - the annual report to shareholders;

- the annual information form;
- prospectuses;
- other public reports requiring approval by the Board; and
- press releases related thereto;
- and report to the Board with respect thereto;
- review regulatory filings and decisions as they relate to the Corporation's consolidated financial statements;
- review the appropriateness of the policies and procedures used in the preparation of the Corporation's consolidated financial statements and other required disclosure documents, and consider recommendations for any material change to such policies;
- review and report on the integrity of the Corporation's consolidated financial statements;
- review the minutes of any audit committee meeting of any subsidiary of the Corporation;
- review with management, the external auditors and, if necessary, with legal counsel, any litigation, claim or other contingency, including tax assessments that could have a material effect 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;
- review the Corporation's compliance with regulatory and statutory requirements as they relate to financial statements, tax matters and disclosure of material facts;
- develop a calendar of activities to be undertaken by the Committee for each ensuing year related to the Committee's duties and responsibilities as set forth in this Charter and to submit the calendar in the appropriate format to the Board of Directors within a reasonable period of time following each annual general meeting of shareholders;
- ensure all material public documents relating to the financial performance, financial position or analysis thereon are reviewed by the Committee or another appropriate committee, as designated by the Board of Directors. In certain cases which involve severe timing considerations, the Committee may designate the responsibility for review to any two members of the Committee. The Committee shall review and monitor practices and procedures adopted by the Corporation to assure compliance with applicable listing requirements, laws, regulations and other rules, and where appropriate, make recommendations or reports thereon to the Board of Directors;
- The Committee shall review significant changes in the accounting principles to be observed in the preparation of the accounts of the Corporation and its subsidiaries, or in their application, and in financial disclosure presentation; and
- The Committee shall prepare or review such reports as may be required by any applicable securities regulatory authority to be included in the Corporation's Information Circular or any other disclosure document of the Corporation.

Accountability

The Committee shall report its activities and proceedings to the Board by distributing the minutes of its meetings or by oral or written report at the next Board meeting.

Standards of Liability

Nothing contained in this mandate is intended to expand applicable standards of liability under statutory, regulatory, common law or any other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in this mandate are meant to serve as guidelines rather than inflexible rules and the Committee may adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities.

Annual Review And Assessment

The Committee shall conduct an annual review and assessment of its performance, including compliance with this Charter and its role, duties and responsibilities, and submit such report orally or in writing to the Board of Directors.

Committee Timetable

The major activities of the Committee with respect to scheduled meetings will be outlined in an annual schedule.