CANADIAN NATURAL RESOURCES LTD
Form 40-F
March 27, 2009

United States
Securities and Exchange Commission
Washington, D.C. 20549

FORM 40-F

[ ] Registration Statement pursuant to section 12 of the Securities Exchange Act of 1934

[X] Annual report pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2008 Commission File Number: 333-146056

CANADIAN NATURAL RESOURCES LIMITED
(Exact name of Registrant as specified in its charter)

ALBERTA, CANADA
(Province or other jurisdiction of incorporation or organization)

1311
(Primary Standard Industrial Classification Code Numbers)

NOT APPLICABLE
(I.R.S. Employer Identification Number (if applicable))

2500, 855-2ND STREET S.W., CALGARY, ALBERTA, CANADA, T2P 4J8
TELEPHONE: (403) 517-7345
(Address and telephone number of Registrant's principal executive offices)

CT CORPORATION SYSTEM, 111-8TH AVENUE, NEW YORK, NEW YORK 10011
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of Each Class:	Name of each exchange on which registered:
COMMON SHARES, NO PAR VALUE	NEW YORK STOCK EXCHANGE

Securities registered or to be registered pursuant to Section 12(g) of the Act:
Title of Each Class: NONE

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: NONE

For annual reports, indicate by check mark the information filed with this Form:

[X] Annual information form [X] Audited annual financial statements

Number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.
540,991,318 COMMON SHARES OUTSTANDING AS OF DECEMBER 31, 2008

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Indicate by check mark whether the Registrant is furnishing the information contained in this Form to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the filing number assigned to the Registrant in connection with such Rule.

Yes [ ] No [X]

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

This Annual Report on Form 40-F shall be incorporated by reference into, or as an exhibit to, as applicable, the Registrant's Registration Statement on Form F-9 (Registration No. 333-146056) under the Securities Act of 1933.

All dollar amounts in this Annual Report on Form 40-F are expressed in Canadian dollars. As of March 26, 2009, the noon buying rate for Canadian Dollars as expressed by the Bank of Canada was US$0.8110 equals C$ 1.00.

PRINCIPAL DOCUMENTS

The following documents have been filed as part of this Annual Report on Form 40-F, starting on the following page:

A. ANNUAL INFORMATION FORM

Annual Information Form of Canadian Natural Resources Limited ("Canadian Natural") for the year ended December 31, 2008.

B. AUDITED ANNUAL FINANCIAL STATEMENTS

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2008 and 2007, including the auditor's report with respect thereto. For a reconciliation of important differences between Canadian and United States generally accepted accounting principles, see Note 18 of the notes to the consolidated financial statements.

C. MANAGEMENT'S DISCUSSION AND ANALYSIS

Canadian Natural's Management's Discussion and Analysis for the year ended December 31, 2008.

SUPPLEMENTARY OIL & GAS INFORMATION

For Canadian Natural's Supplementary Oil & Gas Information for the year ended December 31, 2008, see Exhibit 1 of this Annual Report on Form 40-F.

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[CANADIAN NATURAL RESOURCES LIMITED LOGO OMITTED]

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2008

MARCH 25, 2009

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DEFINITIONS

The following are definitions of selected abbreviations used in this Annual Information Form:

"API" means the specific gravity measured in degrees on the American Petroleum Institute scale

"ARO" means Asset Retirement Obligation

"BBL" or "BARREL" means 34.972 Imperial gallons or 42 US gallons

"BCF" means one billion cubic feet

"BBL/D" means barrels per day

"BOE" means barrel of oil equivalent

"BOE/D" means barrel of oil equivalent per day

"CO2" means carbon dioxide

"CO2E" means carbon dioxide equivalents

"CANADIAN GAAP" means Generally Accepted Accounting Principles in Canada

"CANADIAN NATURAL RESOURCES LIMITED", "CANADIAN NATURAL", or "COMPANY" means Canadian Natural Resources Limited and includes, where applicable, reference to subsidiaries of and partnership interests held by Canadian Natural Resources Limited and its subsidiaries

"CBM" means coal bed methane

"CONVENTIONAL CRUDE OIL, NGLS AND NATURAL GAS" includes all of the Company's light/medium, primary heavy, and thermal heavy crude oil, natural gas, coal bed methane and NGLs reserves. It does not include the Company's oil sands mining reserves

"DEVELOPMENT WELL" means a well drilled into a zone that is known to be productive and expected to produce crude oil or natural gas in the future

"DRY WELL" means a well drilled that is not capable of producing commercial quantities of crude oil or natural gas to justify completion - a dry well will be plugged back, abandoned and reclaimed

"EXPLORATORY WELL" means a well drilled into an unproved territory with the intention to discover commercial quantities of crude oil or natural gas

"FPSO" means a Floating Production, Storage and Offtake vessel

"GHG" means greenhouse gas

"GROSS ACRES" means the total number of acres in which the Company holds a working interest or the right to earn a working interest

"GROSS WELLS" means the total number of wells in which the Company has a working interest

"HORIZON PROJECT" means the Horizon Oil Sands Project

"MBBL" means one thousand barrels

"MCF" means one thousand cubic feet

"MCF/D" means one thousand cubic feet per day

"MMBBL" means one million barrels

"MMBTU" means one million British thermal units

"MMCF" means one million cubic feet

"MMCF/D" means one million cubic feet per day

"NGLS" means natural gas liquids

"NET ACRES" refers to gross acres multiplied by the percentage working interest therein owned or to be owned by the Company

"NET ASSET VALUE" means the discounted value of conventional crude oil and natural gas reserves plus the value of undeveloped land, less net debt

"NET WELLS" refers to gross wells multiplied by the percentage working interest therein owned or to be owned by the Company

"PRODUCTIVE WELL" means a well that is not a dry well

"PRT" means Petroleum Revenue Tax

"SAGD" means steam-assisted gravity drainage

"SCO" means synthetic light crude oil

"SEC" means United States Securities and Exchange Commission

"UNDEVELOPED ACREAGE" refers to lands on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas

"UK" means the United Kingdom

"US" means United States

"WORKING INTEREST" means the interest held by the Company in a crude oil or natural gas property, which interest normally bears its proportionate share of the costs of exploration, development, and operation as well as any royalties or other production burdens

"WTI" means West Texas Intermediate

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could" "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort" "seeks", "schedule" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, production volumes, royalties, operating costs, capital expenditures, and other guidance provided throughout this document constitute forward looking statements. Disclosure of plans relating to existing and future developments, including but not limited to the Horizon Project, Primrose East, Pelican Lake, Gabon Offshore West Africa, and the Kirby Oil Sands Project also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year if necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained and are subject to known and unknown risks, uncertainties and other factors that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete its capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected difficulties in mining, extracting or upgrading the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, bitumen, natural gas and liquids not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses. Certain of these factors are discussed in more detail under the heading "Risk Factors". The Company's operations have been, and at times in the future may be affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or Management's estimates or opinions change.

SPECIAL NOTE REGARDING CURRENCY, PRODUCTION AND RESERVES

In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data is presented on a before royalties basis unless otherwise stated. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("boe"). A boe is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6mcf:1bbl). This conversion may be misleading, particularly if used in isolation, since the 6mcf:1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

For the year ended December 31, 2008, the Company retained a qualified independent reserves evaluator, Sproule Associates Limited ("Sproule"), to evaluate 100% of the Company's conventional proved, as well as proved and probable crude oil, NGLs and natural gas reserves and prepare Evaluation Reports on these reserves. Conventional crude oil, NGLs and natural gas reserves include all of the Company's light/medium, primary heavy, and thermal heavy crude oil, natural gas, coal bed methane and NGLs reserves. They do not include the Company's oil sands mining reserves. The Company has been granted an exemption from certain of the provisions of National Instrument 51-101 - "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute SEC requirements for certain disclosures required under NI 51-101. There are three principal differences between the two standards. The first is the requirement under NI 51-101 to disclose both proved and proved and probable reserves, as well as the related net present value of future net revenues using forecast prices and costs. The second is in the definition of proved reserves; however, as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material. The third is the requirement to disclose a gross reserve reconciliation (before the consideration of royalties). The Company discloses its conventional crude oil, NGLs, and natural gas reserve reconciliations net of royalties in adherence to SEC requirements.

For the year ended December 31, 2008, the Company retained a qualified independent reserves evaluator, GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate 100% of Phases 1 through 3 of the Company's Horizon Project and prepare an Evaluation Report on the Company's proved, as well as proved and probable oil sands mining reserves incorporating both the mining and upgrading projects. These reserves were evaluated adhering to the requirements of SEC Industry Guide 7 using year-end constant pricing and have been disclosed separately from the Company's conventional proved and proved and probable crude oil, NGLs and natural gas reserves.

The Company annually discloses proved conventional reserves and the standardized measure of discounted future net cash flows using year-end constant prices and costs as mandated by the SEC in the supplementary crude oil and natural gas information section of the Company's Annual Report and in its annual Form 40-F filing with the SEC. The Company has elected to provide the net present value of these same conventional proved reserves as well as its conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. Net present values of conventional reserves are based upon discounted cash flows prior to the consideration of income taxes and existing asset abandonment liabilities. Future development costs and associated material well abandonment liabilities have been applied. The Company has also elected to provide both proved, and proved and probable conventional reserves and the net present value of these reserves using forecast prices and costs as additional voluntary information, which is disclosed in this Annual Information Form.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with both Sproule and GLJ to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and net present value of remaining conventional crude oil, NGLs and natural gas reserves as well as the Company's quantity of oil sands mining reserves.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

This Annual Information Form includes references to financial measures commonly used in the crude oil and natural gas industry, such as cash flow from operations, adjusted net earnings from operations and net asset value. These financial measures are not defined by generally accepted accounting principles ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with Canadian GAAP in the "Financial Highlights" section the Company's MD&A which is incorporated by reference into this document.

RISK FACTORS

VOLATILITY OF CRUDE OIL AND NATURAL GAS PRICES

The Company's financial condition is substantially dependent on, and highly sensitive to the prevailing prices of crude oil and natural gas. Significant declines in crude oil or natural gas prices could have a material adverse effect on the Company's operations and financial condition and the value and amount of its reserves. Prices for crude oil and natural gas fluctuate in response to changes in the supply of and demand for, crude oil and natural gas, market uncertainty and a variety of additional factors beyond the Company's control. Crude oil prices are determined by international supply and demand. Factors which affect crude oil prices include the actions of the Organization of Petroleum Exporting Countries, the condition of the Canadian, United States, European and Asian economies, government regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions. Natural gas prices realized by the Company are affected primarily in North America by supply and demand, weather conditions, industrial demand, prices of alternate sources of energy, and the import of liquefied natural gas. Any substantial or extended decline in the prices of crude oil or natural gas could result in a delay or cancellation of existing or future drilling, development or construction programs, including but not limited to the Horizon Project, Primrose East, Pelican Lake, Gabon Offshore West Africa, and the Kirby Oil Sands Project, or curtailment in production at some properties or result in unutilized long-term transportation commitments, all of which could have a material adverse effect on Canadian Natural's revenues, net earnings and cash flows.

Canadian Natural conducts an annual assessment of the carrying value of its assets in accordance with Canadian GAAP. If crude oil and natural gas forecast prices decline, the carrying value of property, plant and equipment could be subject to downward revisions, and net earnings could be adversely affected.

Approximately 28% of the Company's 2008 production on a boe basis was primary and thermal heavy crude oil. The market prices for heavy crude oil differ from the established market indices for light and medium grades of crude oil due principally to the quality difference and the mix of product obtained in the refining process referred to as the "quality differential". As a result, the price received for heavy crude oil is generally lower than the price for medium and light crude oil, and the production costs associated with heavy crude oil may be higher than for lighter grades. Future quality differentials are uncertain and a significant increase in the heavy crude oil differentials could have a material adverse effect on the Company's business.

NEED TO REPLACE RESERVES

Canadian Natural's future crude oil and natural gas reserves and production, and therefore its cash flows and results of operations, are highly dependent upon success in exploiting its current reserve base and acquiring or discovering additional reserves. Without additions to reserves through exploration, acquisition or development activities, the Company's production will decline over time as reserves are depleted. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent the Company's cash flows from operations are insufficient to fund capital expenditures and external sources of capital become limited or unavailable, the Company's ability to make the necessary capital investments to maintain and expand its crude oil and natural gas reserves will be impaired. In addition, Canadian Natural may be unable to find and develop or acquire additional reserves to replace its crude oil and natural gas production at acceptable costs.

UNCERTAINTY OF RESERVE ESTIMATES

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the Company's control. In general, estimates of economically recoverable crude oil, NGLs and natural gas reserves and the future net cash flow therefrom are based upon a number of factors and assumptions made as of the date on which the reserve 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 are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable crude oil, NGLs and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Canadian Natural's actual production, revenues, royalties, taxes and development, abandonment and operating expenditures with respect to its reserves will likely vary from such estimates, and such variances could be material.

Estimates with respect to 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 upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

COMPLETION RISK

Canadian Natural has a variety of exploration, development and construction projects underway at any given time. Project delays may result in delayed revenue receipts and cost overruns may result in projects being uneconomic. The Company's ability to complete projects is dependent on general business and market conditions as well as other factors beyond our control including the availability of skilled labour and manpower, the availability and proximity of pipeline capacity, weather, environmental and regulatory matters, ability to access lands, availability of drilling and other equipment, and availability of processing capacity.

COMPETITION IN ENERGY INDUSTRY

The energy industry is highly competitive in all aspects including the exploration for and the development of new sources of supply, the construction and operation of crude oil and natural gas pipelines and related facilities, the acquisition of crude oil and natural gas interests and the transportation and marketing of crude oil, natural gas, NGLs and electricity. Canadian Natural will compete not only among participants in the energy industry but also between petroleum products and other energy sources. The Company's competitors include integrated oil and natural gas companies and numerous other senior oil and natural gas companies, some of which may have financial and other resources greater than the Company.

ACCESS TO SOURCES OF LIQUIDITY

The ongoing worldwide financial and economic events have resulted in a significant tightening of the availability and cost of new sources of liquidity, including bank credit facilities and funds derived from debt capital markets. The ability of the Company to fund current and future capital projects and carry out our business plan is dependent on our ability to raise capital in a timely manner under favourable terms and conditions.

ENVIRONMENTAL RISKS

All phases of the crude oil and natural gas business are subject to environmental regulation pursuant to a variety of Canadian, United States, United Kingdom, European Union and other federal, provincial, state and municipal laws and regulations as well as international conventions (collectively, "environmental legislation").

Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. Environmental legislation also requires that wells, facility sites and other properties associated with the Company's operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition certain types of operations including exploration and development projects and significant changes to certain existing projects may require the submission and approval of environmental impact assessments or permit applications. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the imposition of fines and penalties. The costs of complying with environmental legislation in the future may have a material adverse effect on Canadian Natural's financial condition or results of operations.

The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation, particularly in North America and the North Sea. Existing and expected legislation and regulations will require the Company to address and mitigate the effect of its activities on the environment. Increasingly stringent laws and regulations, including any new regulations the US may impose to limit purchases of crude oil towards less energy intensive sources, may have an adverse effect on the Company's future net earnings and cash flow from operations.

GREENHOUSE GAS AND OTHER AIR EMISSIONS

There are a number of unresolved issues in relation to Canadian federal and provincial GHG regulatory requirements. Key among them is an appropriate common facility emissions threshold, availability and duration of compliance mechanisms and resolution of federal/provincial harmonization agreements. The Company continues to pursue GHG emissions reduction initiatives including solution gas conservation, CO_2 capture and sequestration in oil sands tailings, CO_2 capture and storage in association with enhanced oil recovery and participation in an industry initiative to promote an integrated CO_2 capture and storage network.

Air pollutant standards and guidelines are being developed federally and provincially and the Company is participating in these discussions. Ambient air quality and sector based reductions in air emissions are being reviewed. Through participation of the Company and the industry with stakeholders, guidelines have been developed that adopt a structured process to emissions reductions that is commensurate with technological development and operational requirements.

In Canada, the Federal government has indicated its intent to develop regulations that would be in effect in 2010 to address industrial GHG emissions; however future Federal regulatory requirements currently remain uncertain. The Federal Government has also outlined national and sectoral reduction targets for several categories of air pollutants. In Alberta, GHG regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Two Canadian Natural facilities, the Primrose/Wolf Lake in-situ heavy oil crude oil facilities and the Hays sour natural gas plant, fall under the regulations. In British Columbia, a $10/tonne carbon tax was implemented July 1, 2008, applying to combustion of all fossil fuels, increasing to $30/tonne by July 2012. In the UK, greenhouse gas regulations have been in effect since 2005. During Phase 1 (2005-2007) of the UK National Allocation Plan the Company operated below its CO_2 allocation. For Phase 2 (2008-2012) the Company's CO_2 allocation has been decreased below the Company's estimated current operations emissions. The compliance costs to the Company relating to the above regulations for 2008 are approximately $24 million.

The additional requirements of enacted or proposed GHG legislation on the Company's operations will increase capital expenditures and operating expenses, especially those related to the Horizon Project and the Company's other existing and planned large oil sands projects. This may have an adverse effect on the Company's net earnings and cash flow from operations.

HEDGING ACTIVITIES

In response to fluctuations in commodity prices, foreign exchange, and interest rates, the Company may utilize various derivative financial instruments and physical sales contracts to manage its exposure under a defined hedging program. The terms of these arrangements may limit the benefit to the Company of favourable changes in these factors and may result in financial or opportunity loss due to paying royalties on a reference price which is higher than the hedged price and counterparty credit risk.

OPERATIONAL RISK

Exploring for, producing and transporting petroleum substances involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. These activities are subject to a number of hazards which may result in fires, explosions, spills, blow-outs or other unexpected or dangerous conditions causing personal injury, property damage, environmental damage and interruption of operations. The Company has developed a comprehensive health and safety management framework and maintains a comprehensive insurance program, however, Canadian Natural's liability, property and business interruption insurance may not and possibly will not provide adequate coverage in all circumstances.

FOREIGN INVESTMENTS

The Company's foreign investments involve risks typically associated with investments in developing countries such as uncertain political, economic, legal and tax environments. These risks may include, among other things, currency restrictions and exchange rate fluctuations, loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, war, insurrection and other political risks, risks of increases in taxes and governmental royalties, renegotiation of contracts with governmental entities and quasi-governmental agencies, changes in laws and policies governing operations of foreign-based companies and other uncertainties arising out of foreign government sovereignty over the Company's international operations. In addition, if a dispute arises in its foreign operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of a court in Canada or the United States.

Canadian Natural's arrangement for the exploration and development of crude oil and natural gas properties in Canada and the UK sector of the North Sea differs distinctly from its arrangement for the exploration and development in other foreign crude oil and natural gas properties. In some foreign countries in which the Company does and may do business in the future, the state generally retains ownership of the minerals and consequently retains control of, and in many cases participates in, the exploration and production of reserves. Accordingly, operations may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges. In addition, changes in prices and costs of operations, timing of production and other factors may affect estimates of crude oil and natural gas reserve quantities and future net cash flows attributable to foreign properties in a manner materially different than such changes would affect estimates for Canadian properties. Agreements covering foreign crude oil and natural gas operations also frequently contain provisions obligating the Company to spend specified amounts on exploration and development, or to perform certain operations or forfeit all or a portion of the acreage subject to the contract.

OTHER BUSINESS RISKS

Other business risks relate to the dependency on third party operators for some of the Company's assets, timing and success of integrating the business and operations of acquired companies, credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, risk of litigation, regulatory issues, and risk of increases in government taxes and changes to the royalty regime. The majority of the Company's assets are held in one or more corporate subsidiaries or partnerships. The results of operations and ability to service indebtedness, including debt securities, are dependent upon the results of operations of these subsidiaries and partnerships and, in the case of subsidiaries, the payment of funds to the Company in the form of loans, dividends or other means employed for the payment of funds to the Company. In the event of the liquidation of any corporate subsidiary or partnership, the assets of the subsidiary would be used first to repay the indebtedness of the subsidiary, including trade payables or obligations under any guarantees, prior to being used by the Company to pay its indebtedness.

ENVIRONMENTAL MATTERS

The Company carries out its activities in compliance with all relevant regional, national and international regulations and industry standards. Environmental specialists in Canada and the UK review the operations of the Company's world-wide interests and report on a regular basis to the senior management of the Company, which in turn reports on environmental matters directly to the Health, Safety and Environmental Committee of the Board of Directors.

The Company regularly meets with and submits to inspections by the various governments in the regions where the Company operates. The Company believes that it meets all existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. Since these requirements apply to all operators in the crude oil and natural gas industry, it is not anticipated that the Company's competitive position within the industry will be adversely affected by changes in applicable legislation. The Company has internal procedures designed to ensure that the environmental aspects of new acquisitions and developments are taken into account prior to proceeding. The Company's environmental management plan and operating guidelines focus on minimizing the environmental impact of field operations while meeting regulatory requirements and corporate standards. The Company's proactive program includes: an internal environmental compliance audit and inspection program of its operating facilities; a suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an effective surface reclamation program; a due diligence program related to groundwater monitoring; an active program related to preventing spills and reclaiming spill sites; a solution gas reduction and conservation program; a program to replace the majority of fresh water for steaming with brackish water; environmental planning for all projects to assess environmental impacts and to implement avoidance, and mitigation programs; reporting for environmental liabilities; a program to optimize efficiencies at the Company's operating facilities; and continued evaluation of new technologies to reduce

environmental impacts. The Company has also established stringent operating standards in four areas: implementing cost effective ways of reducing GHG per unit of production; exercising care with respect to all waste produced through effective waste management plans; using water-based, environmentally friendly drilling muds whenever possible; and minimizing produced water volumes onshore and offshore through cost-effective measures. Canadian Natural participates in both the Canadian federal and provincial regulated GHG emissions programs. The Company continues to quantify annual GHG emissions for internal reporting purposes. The Company has participated in the Canadian Association of Petroleum Producers ("CAPP") Stewardship Program since 2000 and is currently a Gold Level Reporter. Canadian Natural continues to invest in proven and new technologies and in improved operating strategies to help us achieve the Companies overall goal of a net reduction of GHG emissions per unit of production.

The Company is concurrently participating with certain industry groups who in turn are working with legislators and regulators to develop and implement new GHG emissions laws and regulations. Internally, the Company is pursuing an integrated emissions reduction strategy. The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new policies encourage innovation, energy efficiency, targeted research and development while not impacting competitiveness.

The Company remains focused on implementing reduction programs based on efficiency audits of its major facilities to reduce CO_2 emissions and on trading mechanisms to ensure compliance with any requirement now in effect. Canadian Natural is committed to managing air emissions through an integrated corporate approach which considers opportunities to reduce both air pollutants and GHG emissions. Air quality programs continue to be an essential part of the Company's environmental work plan and are operated within all regulatory standards and guidelines. The Company strategy for managing GHG emissions is based on four core principles: energy conservation and efficiency; reduced intensity; innovative technology and associated research and development; and, trading capacity, both domestically and globally.

The Company continues to implement flaring, venting and fuel and solution gas conservation programs. In 2008 the Company completed approximately 101 gas conservation projects, resulting in a reduction of 835,000 tonnes/year of CO_2e. Over the past five years the Company has spent over $89 million to conserve the equivalent of over 6.3 million tonnes of CO_2e. The Company also monitors the performance of its compressor fleet which is continually modified and optimized for maximum efficiency. These programs also influence and direct the Company's plans for new projects and facilities. The Horizon Project has incorporated advancements in technology to further reduce GHG emissions through maximizing heat integration, the use of cogeneration to meet steam and electricity demands and the design of the hydrogen production facility to enable CO_2 capture and the sequestration of CO_2 in oils sands tailings.

In its North Sea operations the Company continues to focus on implementing reduction programs based on efficiency audits of its major facilities. Projects to reduce GHG emissions included a flare recovery pilot study, change out of flare purge valves and introduction of water washing on turbines. The Produced Water Re-injection on Ninian Central was made permanent in 2008 during which time approximately 1.36 million cubic meters of produced water were re-injected to the reservoir. This resulted in approximately 18 tonnes of oil in produced water not being discharged to sea, a reduction of approximately 6%.

For 2008, the Company's capital expenditures included $38 million for abandonment expenditures (2007 - $71 million).

The Company's estimated undiscounted ARO at December 31, 2008 was as follows:

Estimated ARO, undiscounted ($millions)	2008	2007
North America	$ 3,165	$ 3,038
North Sea	1,216	1,286
Offshore West Africa	93	102
	4,474	4,426
North Sea PRT recovery	(529)	(555)
	$ 3,945	$ 3,871

The estimate of ARO is based on estimates of future costs to abandon and restore the wells, production facilities and offshore production platforms. Factors that affect costs include number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs in accordance with present legislation and industry operating practice. The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production, lowering costs and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates. The future abandonment costs incurred in the North Sea are estimated to result in a PRT recovery of $529 million (2007 - $555 million), as abandonment costs are an allowable deduction in determining PRT and may be

carried back to reclaim PRT previously paid. The expected PRT recovery reduces the Company's net undiscounted abandonment liability to $3,945 million (2007 - $3,871 million).

REGULATORY MATTERS

The Company's business is subject to regulations generally established by government legislation and governmental agencies. The regulations are summarized in the following paragraphs.

CANADA

The petroleum and natural gas industry in Canada operates under government legislation and regulations, which govern exploration, development, production, refining, marketing, transportation, prevention of waste and other activities.

The Company's Canadian properties are primarily located in Alberta, British Columbia, Saskatchewan, Manitoba and the Northwest and Yukon Territories. Most of these properties are held under leases/licences obtained from the respective provincial or federal governments, which give the holder the right to explore for and produce crude oil and natural gas. The remainder of the properties are held under freehold (private ownership) lands.

Conventional petroleum and natural gas leases issued by the provinces of Alberta, Saskatchewan and Manitoba have a primary term from two to five years, and British Columbia leases/licences presently have a term of up to ten years. Those portions of the leases that are producing or are capable of producing at the end of the primary term will "continue" for the productive life of the lease.

The exploration licences in the Northwest and Yukon Territories are administered by the Federal Government and only grant the right to explore. They have initial terms of four to five years. A Commercial Discovery Licence must be obtained in order to produce crude oil and natural gas, which requires approval of a development plan.

An Alberta oil sands permit and oil sands primary lease is issued for five and fifteen years respectively. If the minimum level of evaluation of an oil sands permit is attained, a primary oil sands lease will be issued out of the permit. A primary oil sands lease is continued based on the minimum level of evaluation attained on such lease. Continued primary oil sands leases that are designated as "producing" will continue for their productive lives while those designated as "non-producing" can be continued by payment of escalating rentals.

The provincial governments regulate the production of crude oil and natural gas as well as the removal of natural gas and NGLs from each province. Government royalties are payable on crude oil, NGLs and natural gas production from leases owned by the province. The royalties are determined by regulation and are generally calculated as a percentage of production varied by a number of different factors including selling prices, production levels, recovery methods, transportation and processing costs, location and date of discovery.

The Alberta Government implemented its New Royalty Framework (NRF) effective January 1, 2009. The NRF includes a number of changes to royalty rates for natural gas, conventional crude oil, and oil sands production. Under the NRF, royalties payable are variable according to commodity prices and the productivity of wells.

The NRF for conventional crude oil and natural gas operates based on sliding scales ranging up to 50% determined by commodity prices and well productivity.

Government royalties on a significant portion of Alberta crude oil production fall under the oil sands royalty regime and are calculated on a project by project basis as a percentage of gross revenue less operating, capital and abandonment costs ("net profit"). For 2008 and prior years, royalties were calculated as 1% of gross revenues until the Company's capital investment in the applicable project were fully recovered, at which time the royalty increased to 25% of net profit. Effective January 1, 2009 the NRF includes the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout depending on benchmark crude oil pricing.

In addition to government royalties, the Company is currently subject to federal and provincial income taxes in Canada at a combined rate of approximately 29% after allowable deductions.

During 2007, the Canadian Federal Government enacted income tax rate changes which decrease the Federal corporate income tax rate over a five year period from 21% in 2007, 19.5% in 2008, 19% in 2009, to 15% in 2012.

UNITED KINGDOM

Under existing law, the UK Government has broad authority to regulate the petroleum industry, including exploration, development, conservation and rates of production.

Crude oil and natural gas fields granted development approval before March 16, 1993 are subject to UK Petroleum Revenue Tax ("PRT") of 50% charged on crude oil and natural gas profits. Approvals granted on or after March 16, 1993 are exempted from PRT and government royalties. Profits for PRT purposes are calculated on a field-by-field basis by deducting field operating costs and field development costs from production and third-party tariff revenue. In addition, certain statutory allowances are available, which may reduce the PRT payable. There is no PRT on profits of decommissioned fields subsequently redeveloped, subject to certain conditions being met.

The Company is subject to UK Corporation Tax ("CT") on its UK profits at a current rate of 30%. PRT paid is deductible for CT purposes. An additional Supplementary Charge Tax ("SCT") of 20% is charged on crude oil and natural gas profits but excludes any deduction for financing costs. The deduction for crude oil and natural gas expenditures on capital items is generally 100% in the year incurred.

OFFSHORE WEST AFRICA

Terms of licences, including royalties and taxes payable on production or profit sharing arrangements, vary by country and, in some cases, by concession within each country.

Development of the Espoir Field in Block CI-26 and the Baobab Field in Block CI-40, offshore Cote d'Ivoire, are subject to Production Sharing Agreements ("PSA") that deem tax or royalty payments to the Government are met from the Government's share of profit oil. The current Corporate Income Tax rate in Cote d'Ivoire is 25% which is applicable to non PSA income.

The Olowi Field offshore Gabon is also under the terms of a PSA which deems tax or royalty payments to the Government are met from the Government's share of profit oil. The current Corporate Income Tax rate is 35% which is applicable to non PSA income.

THE COMPANY

Canadian Natural Resources Limited was incorporated under the laws of the Province of British Columbia on November 7, 1973 as AEX Minerals Corporation (N.P.L.) and on December 5, 1975 changed its name to Canadian Natural Resources Limited. Canadian Natural was continued under the COMPANIES ACT OF ALBERTA on January 6, 1982 and was further continued under the BUSINESS CORPORATIONS ACT (Alberta) on November 6, 1985. The head, principal and registered office of the Company is located in Calgary, Alberta, Canada at 2500, 855 -- 2nd Street S.W., T2P 4J8.

Canadian Natural formed a wholly owned subsidiary, CanNat Resources Inc. ("CanNat") in January 1995.

Pursuant to a Plan of Arrangement, the Company acquired all of the outstanding shares of Sceptre Resources Limited ("Sceptre") in September 1996 and in January 1997, Sceptre and CanNat amalgamated pursuant to the BUSINESS CORPORATIONS ACT (Alberta) under the name CanNat Resources Inc.

Pursuant to an Offer to Purchase all of the outstanding shares, the Company completed the acquisition of Ranger Oil Limited ("Ranger"), including its subsidiaries, in July 2000. On October 1, 2000 Ranger and the Company amalgamated pursuant to the BUSINESS CORPORATIONS ACT (Alberta) under the name Canadian Natural Resources Limited.

Pursuant to a Plan of Arrangement, the Company acquired all of the outstanding shares of Rio Alto Exploration Ltd. ("RAX") in July 2002. On January 1, 2003, RAX and the Company amalgamated pursuant to the BUSINESS CORPORATIONS ACT (Alberta) under the name Canadian Natural Resources Limited.

On January 1, 2004, CanNat and the Company amalgamated pursuant to the BUSINESS CORPORATIONS ACT (Alberta) under the name Canadian Natural Resources Limited.

On November 2, 2006, pursuant to a Purchase and Sale Agreement, the Company acquired all of the outstanding shares of Anadarko Canada Corporation, a subsidiary of Anadarko Petroleum Corporation. On November 3, 2006 Anadarko Canada Corporation and a wholly owned subsidiary of the Company, 1266701 Alberta Ltd. amalgamated to form ACC-CNR Resources Corporation. On January 1, 2007, ACC-CNR Resources Corporation and the Company amalgamated pursuant to the BUSINESS CORPORATIONS ACT (Alberta) under the name Canadian Natural Resources Limited.

On January 1, 2008 Ranger Oil (International) Ltd., 764968 Alberta Inc., CNR International (Norway) Limited, Renata Resources Inc. and the Company amalgamated pursuant to the BUSINESS CORPORATIONS ACT (Alberta) under the name

Canadian Natural Resources Limited.

The main operating subsidiaries and partnerships of the Company, percentage of voting securities owned either directly or indirectly, and their jurisdictions of incorporation are as follows:

SUBSIDIARY	JURISDICTION OF INCORPORATION
CanNat Energy Inc.	Delaware
CNR (ECHO) Resources Inc.	Alberta
CNR International (U. K.) Investments Limited	England
CNR International (U. K.) Limited	England
CNR International Cote d'Ivoire SARL	Cote d'Ivoire
CNR International (Olowi) Limited	Bahamas
CNR Petro Resources Limited	Alberta
Horizon Construction Management Ltd.	Alberta
PARTNERSHIP	
Canadian Natural Resources Partnership	Alberta
Canadian Natural Resources Northern Alberta Partnership	Alberta
CNR 2006 Partnership	Alberta

In the ordinary course of business, Canadian Natural restructures its subsidiaries and partnerships to maintain efficient operations and to facilitate acquisitions and divestitures.

The consolidated financial statements of Canadian Natural include the accounts of the Company and all of its subsidiaries and partnerships.

GENERAL DEVELOPMENT OF THE BUSINESS - THREE YEAR HISTORY

2006

In January 2006 the Company issued $400 million of 4.50% unsecured notes maturing January 23, 2013 pursuant to a short form Canadian base shelf prospectus dated August 29, 2005.

On August 17, 2006, the Company issued US$250 million of 10 year 6.0% unsecured notes maturing August 15, 2016 and US$450 million of 30 year 6.50% unsecured notes maturing February 15, 2037 pursuant to a US short form base shelf prospectus dated June 3, 2005.

In November 2006, the Company completed the acquisition of Anadarko Canada Corporation ("ACC") for net cash consideration of $4,641 million, including working capital and other adjustments. The Company immediately integrated ACC into its ongoing operations. The land and production base acquired are located substantially in Western Canada and are natural gas weighted assets with a long reserve life. At the time, the assets produced in excess of 350 mmcf/d of natural gas and approximately 9,000 bbl/d of light crude oil and NGLs production. The assets acquired also included approximately 1.5 million net undeveloped acres and key strategic facilities in Northeast British Columbia and Northwest Alberta. In conjunction with the closing of the acquisition of ACC, the Company executed a $3,850 million, three-year non-revolving syndicated credit facility maturing in October 2009. In March 2007, $1,500 million of the credit facility was repaid reducing the facility to $2,350 million. In February 2009, $420 million of the credit facility was repaid reducing the facility to $1,930 million.

During 2006, the Company completed 83 transactions in the normal course to acquire additional interests in crude oil and natural gas properties. The aggregate net expenditure of the transactions was $4,801 million, including the ACC acquisition. The properties acquired are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. As well the Company participated in 48 transactions to dispose of non-core operated and non-operated properties for proceeds of $68 million. Included in this amount is a royalty disposition for $66 million.

2007

On March 19, 2007, the Company issued US$1,100 million of 10 year 5.70% unsecured notes maturing May 15, 2017 and US$1,100 million of 30 year 6.25% unsecured notes maturing March 15, 2038 pursuant to a US short form base shelf prospectus dated November 27, 2006.

On December 18, 2007 the Company issued $400 million of 3 year 5.50% unsecured notes maturing December 17, 2010 pursuant to a Canadian short form base shelf prospectus dated September 25, 2007.

During 2007, the Company completed 67 transactions in the normal course to acquire additional interests in crude oil and natural gas properties. The aggregate net expenditure of the transactions was $70.9 million. The properties acquired are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. As well the Company participated in 33 transactions to dispose of non-core operated and non-operated properties for proceeds of $109.9 million.

2008

On January 17, 2008, the Company issued US$400 million of 5 year 5.15% unsecured notes maturing February 1, 2013, US$400 million of 10 year 5.90% unsecured notes maturing February 1, 2018 and US$400 million of 31 year 6.75% unsecured notes maturing February 1, 2039 pursuant to a US short form base shelf prospectus dated September 25, 2007.

In the third quarter of 2008, the Company committed 120,000 bbl/d to the Keystone Pipeline US Gulf Coast Expansion for a 20 year period, subject to regulatory approval. Concurrently the Company entered into a 20 year supply agreement with a major US refiner for 100,000 bbl/d of heavy crude oil to US Gulf Coast refineries, contingent on the completion of the Keystone Pipeline US Gulf Coast Expansion.

The Company entered into an agreement in August 2005 to obtain pipeline transportation service for the Horizon Project. The initial term of the agreement is 25 years, which commenced on the in-service date of November 1, 2008. The twinning of the existing Alberta Oil Sands Pipeline ("AOSPL"), resulting in two parallel pipelines, one of which is dedicated to Canadian Natural, combined with the new pipeline constructed from the Horizon Project site down to the AOSPL Terminal (collectively, the "Horizon Pipeline") will provide crude oil transportation service for the Horizon Project. In addition to having the option to renew the agreement for successive 10 year terms, the Company has the right to request incremental expansion of the Horizon Pipeline based upon applicable National Energy Board approved multi pipeline economics. This agreement allows the Company to gain access to major sales pipelines out of Edmonton for the Company's synthetic crude oil transportation service for the Horizon Project, while at the same time providing significant quality benefits associated with being the only shipper on the Horizon Pipeline.

During 2008, the Company completed 55 transactions in the normal course to acquire additional interests in crude oil and natural gas properties. The aggregate net expenditure of the transactions was $381 million. The properties acquired are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. As well, the Company participated in 33 transactions to dispose of non-core operated and non-operated properties for proceeds of $45 million.

2009

First synthetic crude oil production was achieved at the Horizon Project on February 28, 2009. First shipment into the Horizon Pipeline occurred on March 18, 2009. Capital expenditures are expected to be $621 million in 2009 for remaining Phase 1 construction, commissioning and inventory costs, as wells as sustaining capital costs and Tranche 2 expansion.

For 2009, the Company's overall conventional drilling activity in North America is expected to comprise approximately 142 natural gas wells and 465 crude oil wells, excluding stratigraphic and service wells. The company has reduced 2009 natural gas drilling in Alberta due to the anticipated future impact of royalty changes arising under the NRF which became effective January 1, 2009 and the current low prices received for natural gas. Forecasted conventional capital expenditures in North America for 2009 are currently expected to be approximately $1.7 billion, excluding property acquisitions and dispositions.

The Company's drilling activity in 2009 for the North Sea is expected to be 0.9 net platform wells with focus on building drilling and workover inventory for 2010. Capital expenditures are expected to be $141 million.

In Offshore West Africa, capital expenditures are expected to be $553 million in 2009, including $80 million to complete Phase 2 development of the Baobab Field in Cote d'Ivoire, where the Company is currently drilling the fourth and final well which is expected to be completed in the second quarter of 2009.

DESCRIPTION OF THE BUSINESS

Canadian Natural is a Canadian based senior independent energy company engaged in the acquisition, exploration, development, production, marketing and sale of crude oil, NGLs, natural gas and bitumen production. The Company's principal core regions of operations are western Canada, the United Kingdom sector of the North Sea and Offshore West Africa.

The Company initiates, operates and maintains a large working interest in a majority of the prospects in which it participates. Canadian Natural's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value on a per common share basis through the development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves.

The Company has a full complement of management, technical and support staff to pursue these objectives. As at December 31, 2008 the Company had 3,782 permanent employees in North America and 350 permanent employees in its international operations. Included in the North American numbers are the Horizon Project team, consisting of 1,245 permanent employees.

The Company focuses on exploiting its core properties and actively maintaining cost controls. Whenever possible Canadian Natural takes on significant ownership levels, operates the properties and attempts to dominate the local land position and operating infrastructure. The Company has grown through a combination of internal growth and strategic acquisitions. Acquisitions are made with a view to either entering new core regions or increasing presence in existing core regions.

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces namely: natural gas, light/medium crude oil and NGLs, Pelican Lake crude oil (14-17(0) API oil, which receives medium quality crude netbacks due to lower production costs and lower royalty rates), primary heavy crude oil, and thermal heavy crude oil. The Company's operations are centred on balanced product offerings, which together provide complementary infrastructure and balance throughout the business cycle. Natural gas is the largest single commodity sold, accounting for 44% of 2008 production. Virtually all of the Company's natural gas and NGLs production is located in the Canadian provinces of Alberta, British Columbia and Saskatchewan and is marketed in Canada and the United States. Light/medium crude oil and NGLs, representing 22% of 2008 production, is located principally in the Company's North Sea and Offshore West Africa properties, with additional production in the provinces of Saskatchewan, British Columbia and Alberta. Primary and thermal heavy crude oil operations in the provinces of Alberta and Saskatchewan account for 28% of 2008 production. Other heavy crude oil, which accounts for 6% of 2008 production, is produced from the Pelican Lake area in north Alberta. This production is developed through a staged horizontal drilling program complimented by water and polymer flooding. Midstream assets, comprised of three crude oil pipelines and an electricity co-generation facility, provide cost effective infrastructure supporting the primary and thermal heavy and Pelican Lake crude oil operations.

With approximately 12.1 million net acres of core undeveloped land base, the Company believes it has sufficient project portfolios in each of the product offerings to provide growth for the next several years.

A. PRINCIPAL CRUDE OIL, NATURAL GAS AND OIL SANDS PROPERTIES

DAILY PRODUCTION AND INFRASTRUCTURE

Set forth below is a summary of the conventional crude oil, NGLs and natural gas properties as at December 31, 2008. The information reflects the working interests owned by the Company. FPSO's, included under major infrastructure, are leased by the Company under varying terms.

	2008 Average Daily Production Rates		2007 Average Daily Production Rates	
Region	Crude oil & NGLs (mbbl)	Natural gas (mmcf)	Crude oil & NGLs (mbbl)	Natural (mm
NORTH AMERICA				
Northeast British Columbia	5.9	377	7.0	
Northwest Alberta	16.4	531	17.0	

Northern Plains	200.7	382	201.4	
Southern Plains	12.2	177	12.7	
Southeast Saskatchewan	8.4	3	8.4	
Non-core regions	0.2	2	0.3	
INTERNATIONAL				
North Sea UK Sector	45.3	10	55.9	
Offshore West Africa				
Cote d'Ivoire	26.6	13	28.5	
Gabon	-	-	-	
Non-core regions				
South Africa	-	-	-	
TOTAL	315.7	1,495	331.2	1,

DEVELOPED AND UNDEVELOPED ACREAGE

The following table summarizes the Companies landholdings as at December 31, 2008.

	Developed Acreage		Undeveloped Acreage		Total A
Region (thousands of acres)	Gross	Net	Gross	Net	Gross
NORTH AMERICA					
Northeast British					
Columbia	1,478	1,107	3,037	2,227	4,515
Northwest Alberta	1,205	859	1,808	1,352	3,013
Northern Plains	4,126	3,326	7,354	6,452	11,480
Southern Plains	1,603	1,251	975	832	2,578
Southeast Saskatchewan	89	73	146	130	235
In-Situ Oil Sands	23	23	598	495	621
Horizon Oil Sands	-	-	115	115	115
Non-core regions	23	8	1,276	179	1,299
INTERNATIONAL					
North Sea UK Sector	108	74	314	258	422
Offshore West Africa					
Cote d'Ivoire	7	4	95	55	102
Gabon	-	-	152	137	152
Non-core regions					
South Africa	-	-	4,002	4,002	4,002
TOTAL	8,662	6,725	19,872	16,234	28,534

DRILLING ACTIVITY

Set forth below is a summary of conventional crude oil, NGLs and natural gas drilling activity of the Company for the fiscal year ending December 31, 2008 by geographic region:

		2008						
		Exploration						
		Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total	Crude Oil	Natural Gas
NORTH AMERICA								
Northeast								
British Columbia	Gross	-	2.0	2.0	-	4.0	-	26.0
	Net	-	1.5	1.5	-	3.0	-	22.5
Northwest Alberta	Gross	1.0	14.0	1.0	-	16.0	14.0	62.0
	Net	0.6	12.6	0.9	-	14.1	8.9	54.0
Northern Plains	Gross	27.0	14.0	5.0	-	46.0	583.0	131.0
	Net	26.3	11.4	5.0	-	42.7	557.3	88.4
Southern Plains	Gross	4.0	6.0	1.0	-	11.0	29.0	153.0
	Net	4.0	6.0	1.0	-	11.0	26.9	72.8
Southeast								
Saskatchewan	Gross	6.0	-	2.0	-	8.0	57.0	-
	Net	4.6	-	2.0	-	6.6	48.9	-
Non-core Regions	Gross	-	-	-	-	-	-	3.0
	Net	-	-	-	-	-	-	0.1
NORTH SEA								
UK SECTOR	Gross	1.0	-	-	-	1.0	2.0	-
	Net	0.8	-	-	-	0.8	1.6	-
OFFSHORE	Gross	-	-	-	-	-	4.0	-
WEST AFRICA								
	Net	-	-	-	-	-	2.3	-
TOTAL	GROSS	39.0	36.0	11.0	-	86.0	689.0	375.0
	NET	36.3	31.5	10.4	-	78.2	645.9	237.8

Total success rate excluding service and stratigraphic test wells for 2008 is 96% (2007 - 91%, 2006 - 91%)

2007

		Exploration						
		Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total	Crude Oil	Natural Gas
NORTH AMERICA								
Northeast British Columbia	Gross	-	7.0	7.0	-	14.0	3.0	45.0
	Net	-	7.0	6.0	-	13.0	2.9	35.1
Northwest Alberta	Gross	1.0	23.0	5.0	-	29.0	21.0	102.0
	Net	1.0	16.4	3.8	-	21.2	12.1	82.1
Northern Plains	Gross	26.0	31.0	20.0	97.0	174.0	545.0	82.0
	Net	23.8	24.7	19.4	97.0	164.9	500.6	70.9
Southern Plains	Gross	1.0	14.0	1.0	-	16.0	19.0	174.0
	Net	1.0	13.4	1.0	-	15.4	18.1	134.1
Southeast Saskatchewan	Gross	1.0	-	-	-	1.0	27.0	-
	Net	1.0	-	-	-	1.0	23.0	-
Non-core Regions	Gross	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-
NORTH SEA UK SECTOR	Gross	-	-	-	-	-	4.0	-
	Net	-	-	-	-	-	3.7	-
OFFSHORE WEST AFRICA	Gross	-	-	-	-	-	7.0	-
	Net	-	-	-	-	-	4.1	-
TOTAL	Gross	29.0	75.0	33.0	97.0	234.0	626.0	403.0
	Net	26.8	61.5	30.2	97.0	215.5	564.5	322.2

2006

		Exploration						
		Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total	Crude Oil	Natural Gas

NORTH AMERICA								
Northeast British Columbia	Gross	2.0	19.0	6.0	-	27.0	12.0	166.0
	Net	2.0	15.1	5.6	-	22.7	10.9	148.0
Northwest Alberta	Gross	2.0	22.0	10.0	-	34.0	19.0	165.0
	Net	2.0	15.7	9.5	-	27.2	12.5	137.1
Northern Plains	Gross	18.0	110.0	31.0	129.0	288.0	504.0	175.0
	Net	13.6	90.6	28.2	128.9	261.3	470.4	128.1
Southern Plains	Gross	2.0	34.0	9.0	-	45.0	6.0	154.0
	Net	2.0	29.8	8.4	-	40.2	4.2	74.4
Southeast Saskatchewan	Gross	-	-	-	-	-	84.0	-
	Net	-	-	-	-	-	72.7	-
Non-core Regions	Gross	-	2.0	-	-	2.0	2.0	8.0
	Net	-	0.6	-	-	0.6	0.5	2.2
NORTH SEA UK SECTOR	Gross	-	-	-	-	-	8.0	-
	Net	-	-	-	-	-	7.4	-
OFFSHORE WEST AFRICA	Gross	-	-	-	-	-	7.0	-
	Net	-	-	-	-	-	4.1	-
TOTAL	Gross	24.0	187.0	56.0	129.0	396.0	642.0	668.0
	Net	19.6	151.8	51.7	128.9	352.0	582.7	489.8

PRODUCING CRUDE OIL & NATURAL GAS WELLS

Set forth below is a summary of the number of gross and net wells within the Company that were producing or capable of producing as of December 31, 2008:

	Natural gas wells		Crude oil wells	
	Gross	Net	Gross	Net
NORTH AMERICA				
Northeast British Columbia	1,568	1,297.5	223	191.4
Northwest Alberta	2,173	1,696.6	588	334.5
Northern Plains	4,057	3,281.8	5,800	5,276.2
Southern Plains	7,405	6,236.6	1,169	1,073.3
Southeast Saskatchewan	2	2.0	1,239	878.7
Non-core regions	69	24.2	127	23.8
UNITED STATES	4	0.4	2	0.3
NORTH SEA UK SECTOR	2	0.1	111	93.8
OFFSHORE WEST AFRICA				
Cote d'Ivoire	-	-	23	13.4
Total	15,280	12,539.2	9,282	7,885.4

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Any reserves data in the following property report is based on the applicable independent engineering report. See "Conventional Crude Oil, NGLs and Natural Gas Reserves" and "Oil Sands Mining Reserves".

NORTHEAST BRITISH COLUMBIA

[GRAPHIC OMITTED -- Map of Canadian Natural Lands in the NE BC Area]

Significant geological variation extends throughout the productive reservoirs in this region located west of the British Columbia and Alberta border to Prince George, producing light crude oil, NGLs and natural gas.

Crude oil reserves are found primarily in the Halfway formation, while natural gas and associated NGLs are found in numerous carbonate and sandstone formations at depths up to 4,500 vertical meters. The exploration strategy focuses on comprehensive evaluation through two-dimensional seismic, three-dimensional seismic and targeting economic prospects close to existing infrastructure. The region has a mix of low risk multi-zone targets, deep higher risk exploration plays and emerging unconventional shale gas plays. The 2006 acquisition of ACC significantly increased the asset base in this area. The southern portion of this region encompasses the Company's BC Foothills assets where natural gas is produced from the deep Mississippian and Triassic aged reservoirs in this highly deformed structural area.

NORTHWEST ALBERTA

[GRAPHIC OMITTED -- Map of Canadian Natural Lands in the NE AB Area]

This region is located along the border of British Columbia and Alberta west of Edmonton. The majority of the Company's initial holdings in the region were obtained through the 2002 acquisition of Rio Alto Exploration; subsequent to 2002 the Company augmented these holdings with additional land purchases, acquisitions and in 2006 the purchase of the ACC assets. The ACC acquisition added two very prospective properties to this region, Wild River and Peace River Arch. The Wild River assets provide a premium developed and undeveloped land base in the deep basin, multi-zone gas fairway and the Peace River Arch assets provide premium lands in a multi-zone region along with key infrastructure. Northwest Alberta provides exploration and exploitation opportunities in combination with an extensive owned and operated infrastructure. In this region, Canadian Natural produces liquids rich natural gas from multiple, often technically complex horizons, with formation depths ranging from 700 to 4,500 meters. The northern portion of this core region provides extensive multi-zone Cretaceous opportunities similar to the geology of the Company's Northern Plains core region. The Company is also pursuing development of a Doig shale gas play in this region. The southern portion provides exploration and development opportunities in the regionally extensive Cretaceous Cardium formation and in the deeper, tight gas formations throughout the region. The Cardium is a complex, tight natural gas reservoir where high productivity may be achieved due to greater matrix porosity or natural fracturing. The south western portion of this region also contains significant Foothills assets with natural gas produced from the deep Mississippian and Triassic aged reservoirs.

NORTHERN PLAINS

[GRAPHIC OMITTED -- Map of Canadian Natural Lands in the Northern Plains Area]

This region extends just south of Edmonton north to Fort McMurray and from the Northwest Alberta area extending into western Saskatchewan. Over most of the region, both sweet and sour natural gas reserves are produced from numerous productive horizons at depths up to approximately 1,500 meters. In the southwest portion of the region, NGLs and light crude oil are also encountered at slightly greater depths. The region continues to be one of the Company's largest natural gas producing regions.

Natural gas in this region is produced from shallow, low-risk, multi-zone prospects and more recently from the Horseshoe Canyon CBM. The Company targets low-risk exploration and development opportunities and plans to expand its commercial Horseshoe Canyon CBM project. Evaluation of the potential production of CBM from the Mannville coals commenced in 2006 with the drilling of three horizontal wells. The three well pilot was deemed not commercial and the wells were suspended in 2008.

Near Lloydminster, Alberta, reserves of heavy crude oil (averaging 12(Degree)-14(degree) API) and natural gas are produced through conventional vertical, slant and horizontal well bores from a number of productive horizons up to 1,000 meters deep. The energy required to flow the heavy crude oil to the wellbore in this type of heavy crude oil reservoir comes from solution gas. The crude oil viscosity and the reservoir quality will determine the amount of crude oil produced from the reservoir which will vary from 3% to 20% of the original crude oil in place. A key component to maintaining profitability in the production of heavy crude oil is to be a low-cost producer. The Company continues to achieve low costs producing heavy crude oil by holding a dominant position that includes a significant land base and an extensive infrastructure of batteries and disposal facilities.

The Company's holdings in this region of primary heavy oil production are the result of Crown land purchases and several acquisitions including Sceptre Resources, Ranger Oil and Petrovera, as well as acquisitions from Koch Exploration. Included in this area is the 100% owned ECHO Pipeline system which is a high temperature, insulated crude oil transportation pipeline that eliminates the requirement for field condensate blending. The pipeline, which has a capacity of up to 72,000 bbl/d, enables the Company to transport its own production volumes at a reduced operating cost as well as earn third-party transportation revenue. This transportation control enhances the Company's ability to control the full spectrum of costs associated with the development and marketing of its heavy crude oil.

Included in the northern part of this region, approximately 200 miles north of Edmonton, are the Company's holdings at Pelican Lake. These assets produce crude oil from the Wabasca formation with gravities of 14(Degree)-17(Degree) API. Production costs are low due to the absence of sand production, its associated disposal requirements and the gathering and pipeline facilities in place. The Company has the major ownership position in the necessary infrastructure, including roads, drilling pads, gathering and sales pipelines, batteries, gas plants and compressors, to ensure economic development of the large crude oil pool located on the lands, including the 62% owned and operated Pelican Lake Pipeline. The Company holds and controls approximately 75% of the known Wabasca crude oil pool in the Pelican Lake area. It is estimated the Wabasca pool contains approximately four billion barrels of original crude oil in place but is only expected to achieve less than a 5% average recovery factor using primary production on the Company's developed leases. The Company is using an Enhanced Oil Recovery ("EOR") scheme through both water and polymer flooding to increase the ultimate recoveries from the field. To date approximately 11% of the field has been converted to waterflood and there are three producing polymer production wells and 70 polymer injection wells. Pelican Lake production averaged approximately 37,000 bbl/d in 2008 (2007-34,000 bbl/d). The Company is continuing to drill and convert wells to polymer injection in 2009.

Production from the 100% owned Primrose and Wolf Lake Fields located near Bonnyville, Alberta involves processes that utilize steam to increase the recovery of the heavy (10(Degree)-11(Degree)API) crude oil. The two processes employed by the Company are Cyclic Steam Stimulation (CSS) and Steam Assisted Gravity Drainage ("SAGD"). Both recovery processes inject steam to heat the heavy crude oil deposits, reducing the oil viscosity and thereby improving its flow characteristics. There is also an infrastructure of gathering systems, a processing plant with a capacity of 119,500 bbl/d, and the 15% Company owned Cold Lake Pipeline. The Company also holds a 50% interest in a co-generation facility capable of producing 84 megawatts of electricity for the Company's use and sale into the Alberta power grid at pool prices. Since acquiring the assets from BP Amoco in 1999, the Company has successfully converted the field from low-pressure steaming to high-pressure steaming. This conversion resulted in a significant improvement in well productivity and in ultimate oil recovery. A mature SAGD heavy oil project in which the Company holds a 50% interest is also in operation in the Saskatchewan portion of this region. The Regulatory application for the Kirby In-Situ Oil Sands Project located approximately 85 km northeast of Lac La Biche was submitted in September 2007 outlining the Company's plan to build a 45,000 bbl/d in-situ oil sands project. Final corporate sanction and project scope will be impacted by environmental regulations and their associated costs. Subject to regulatory approval, crude oil pricing, and capital costs, the Company may proceed with the detailed engineering and design work.

In 2007 the Company received regulatory approval for its Primrose East project, a new facility located about 15 kilometers from its existing Primrose South steam plant and 25 kilometers from its Wolf Lake central processing facility. The Company began construction in 2007 and first oil production was achieved in late October 2008. The expansion added 40,000 bbl/d of capacity. Subsequent to December 31, 2008, operational issues on one of the pads caused steaming to cease on all well pads resulting in the Company switching from the steaming cycle to the production cycle ahead of schedule. The Company is working on rectifying the issue.

SOUTHERN PLAINS AND SOUTHEAST SASKATCHEWAN

[GRAPHIC OMITTED -- Map of Canadian Natural Lands in the Southern Plans / Saskatchewan Areas]

The Southern Plains area is principally located south of the Northern Plains area to the United States border and extending into western Saskatchewan.

Reserves of natural gas, condensate and light gravity crude oil are contained in numerous productive horizons at depths up to 2,300 meters. Unlike the Company's other three natural gas producing regions, which have areas with limited or winter access only, drilling can take place in this region throughout the year. It is economic to drill shallow wells with reduced well spacings in this region despite having smaller overall reserves and lower productivity per well since they achieve a favourable rate of return on capital employed with low drilling costs and long life reserves. The Company's extensive shallow gas assets in this region were augmented by the 2006 acquisition of ACC.

The Company maintains a large inventory of drillable locations on its land base in this region. This region is one of the more mature regions of the Western Canadian Sedimentary Basin and requires continual operational cost control through efficient utilization of existing facilities, flexible infrastructure design and consolidation of interests where appropriate.

The Williston Basin is located in Southeast Saskatchewan with lands extending into Manitoba. This region became a core region of the Company in mid 1996 with the acquisition of Sceptre. This region produces primarily light sour crude oil from as many as seven productive horizons found at depths up to 2,700 meters.

HORIZON OIL SANDS PROJECT

[GRAPHIC OMITTED -- Map of Canadian Natural Lands in the Horizon Oil Sands Project]

Canadian Natural owns a 100% working interest in its Athabasca Oil Sands leases in northern Alberta, of which a portion (being lease 18) is subject to a 5% net carried interest in the bitumen development. The Horizon Project is located on these leases, about 70 kilometers north of Fort McMurray. Figure 1 shows the location of the Horizon Project within Alberta and within the region and Table 1 describes the leases the Company holds in the region.

FIGURE 1 - LOCATION OF THE HORIZON OIL SANDS PROJECT

[GRAPHIC OMITTED -- Map of Horizon Oil Sands Project]
[GRAPHIC OMITTED -- second Map of Horizon Oil Sands Project]

TABLE 1 - CANADIAN NATURAL ATHABASCA REGION OIL SAND LEASES

Short lease name	Official lease number	Lease expiry date(1)	Area in hectares
Lease 18	727912T18	Continued Producing(2)	19,988
Lease 10	7400120010	December 14, 2015	3,840
Lease 25	7401050025	May 17, 2016	1,536
Lease 11	7400120011	December 14, 2015	518
Lease 12	7400120012	December 14, 2015	9,216
Lease 13	7400120013	December 14, 2015	69
Lease 15	7400120015	December 14, 2015	1,536
Lease 19	7402050019	May 30, 2017	5,120
Lease 20	7402050020	May 30, 2017	768
Lease 6	7597050T06	May 6, 2012	2,584
Lease 7	7597050T07	May 6, 2012	1,144

(1) The Company can apply for an extension of the leases past the expiry date.
(2) Pursuant to Section 14 of the Oil Sands Tenure Regulation.

The leases being developed for the Horizon Project are 18, 25, 10, 19 and 20. The project site is accessible by a private road as well as a private airstrip.

The project includes surface oil sands mining, bitumen extraction, bitumen upgrading and associated infrastructure. Mining of the oil sands is done using conventional truck and shovel technology. The ore is then processed through extraction and froth treatment facilities to produce bitumen, which is upgraded on-site into 34 O API SCO. The SCO is transported from the site by the Horizon Pipeline to the Edmonton area for distribution. An on-site cogeneration plant provides power and steam for the operation.

In June 2002, Canadian Natural filed an application for regulatory approval of the Horizon Project. The application included a comprehensive environmental impact assessment and a social and economic assessment and was accompanied by public consultation. A federal-provincial regulatory Joint Review Panel (the "Panel") examined the project in a public hearing in September 2003. The Panel issued its decision report in January 2004, finding the Horizon Project was in the public interest. An Alberta Order-in-Council approval was received in February 2004. Subsequently key approvals were received from Alberta Environment under the ENVIRONMENTAL PROTECTION ACT and WATER ACT, and from Fisheries and Oceans Canada under the FISHERIES ACT.

Site clearing and pre-construction preparation activities commenced in 2004 and the Company received project sanction by the Board of Directors in February 2005, authorizing management to proceed with Phase 1 of the Horizon Project.

First synthetic crude oil production was achieved on February 28, 2009. Full production capacity for Phase 1 is 110,000 bbl/d of SCO and is expected to be achieved in late 2009.

Subsequent planned expansion through Phases 2/3, further broken down into a series of four Tranches, are being re-profiled in order to attain better cost management.

Horizon Project Phase 1 construction costs were approximately $2.7 billion in 2008 and cumulative construction expenditures were approximately $9.5 billion through the end of 2008. In addition, $364 million of expenditures were incurred for commissioning costs and operating and capital inventory for Phase 1 and capital expenditures of $336 million were incurred for Phases 2 and 3. Forecasted expenditures of $621 million are expected to be incurred in 2009 for remaining Phase 1 construction costs, commissioning and inventory costs, as well as sustaining capital costs and Tranche 2 expansion. The total construction cost to completion is expected to be 43% over the original $6.8 billion estimate. These expenditures are direct project costs only and do not include capitalized interest, stock based compensation or lease evaluation.

During the fourth quarter 2008, the Company drilled 92 stratigraphic test wells (2007 - 98, 2006 - 163) to further delineate the ore body and confirm resource quality and quantity.

As of year-end 2008, key development achievements associated with the Horizon Project were as follows:

- Phase 1 work progress is 98.9% complete.
- Mine operations has removed 87.8 million bank cubic meters of overburden material.

REGIONAL AND PROJECT GEOLOGY

Lease 18, the main oil sands lease for the Horizon Project, has a gradual topographic slope from west to east. To the west, the topography begins to rise into the Birch Mountains and reaches an elevation of 485 meters above sea level in the northwest corner of the lease. To the east, the elevation drops sharply at the Athabasca River escarpment to 230 meters above sea level along the river. The Tar and Calumet Rivers flow through the lease.

In the area of the Horizon Project, the oil sands resource is found within the Cretaceous McMurray Formation. The McMurray Formation is comprised of a sequence of uncemented quartz sands and associated shales that reside above the unconformity with the underlying Upper Devonian carbonates (limestone) of the Waterways Formation. The McMurray Formation at the site of the Horizon Project is subdivided into three informal members: lower, middle, and upper. These informal divisions correspond to changes in the depositional environments within the McMurray from predominantly fluvial to tidal/estuarine through to tidal/marine conditions. Most of the Horizon Project's oil sands resource is found within the lower and middle McMurray. The general stratigraphy of the Horizon Project is shown in Figure 2.

FIGURE 2 - GENERAL STRATIGRAPHY OF THE HORIZON OIL SANDS PROJECT

[GRAPHIC OMITTED -- General Stratigraphy]

OIL SANDS MINING RESERVES

The following table sets out Canadian Natural's net reserves, after royalties, of synthetic crude oil from the Horizon Project:

Constant Prices

	As at December 31, 2008	
	Proved Total	Proved and Probable
Net reserves, after royalties (mmbbl)		
Synthetic crude oil	1,946	2,944

NOTE: SYNTHETIC CRUDE OIL RESERVES ARE BASED ON THE UPGRADING OF BITUMEN USING TECHNOLOGIES IMPLEMENTED AT THE HORIZON PROJECT.

For the year ended December 31, 2008, the Company retained GLJ to evaluate 100% of Phase 1 to Phase 3 of the Horizon Project and prepare an Evaluation Report on the Company's proved and probable oil sands mining reserves incorporating both the mining and upgrading projects. These reserves were evaluated adhering to the requirements of SEC Industry Guide 7 using constant pricing and have been disclosed separately from the Company's conventional proved and probable crude oil, NGLs and natural gas reserves. The 2.9 billion barrels of net proved and probable synthetic crude oil reserves shown in the table are produced from 38 years of projected production commencing in 2009.

Figure 3 shows the mining areas associated with the reserves and Figure 4 shows the drill hole coverage used to develop the mine plan.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with GLJ to review the qualifications of and procedures used by the evaluator in determining the estimate of the Company's oil sands mining reserves.

FIGURE 3 - HORIZON OIL SANDS PROJECT RESOURCE AREAS AND GENERAL LAYOUT

[GRAPHIC OMITTED --- map]

FIGURE 4 - HORIZON OIL SANDS PROJECT CORE HOLE COVERAGE

[GRAPHIC OMITTED -- map]

UNITED KINGDOM NORTH SEA

[GRAPHIC OMITTED -- map]

Through its wholly owned subsidiary CNR International (U.K.) Limited, formerly Ranger Oil (U.K.) Limited, the Company has operated in the North Sea for over 30 years and has developed a significant database, extensive operating experience and an experienced staff. In 2008, the Company produced from 13 crude oil fields.

The northerly fields are centered around the Ninian Field where the Company has an 87.1% working interest. The central processing facility is connected to other fields including the Columba Terraces and Lyell Fields where the Company operates with working interests of 91.6% to 100%. The Company also has an interest in the Strathspey Field and 12 licences covering 20 exploration blocks and part blocks surrounding the Ninian and Murchison platforms. The Company also has a 66.5% working interest in the abandoned Hutton Field.

In the central portion of the North Sea, the Company holds a 87.6% operated working interest in the Banff Field and also owns a 45.7% operated working interest in the Kyle Field. Production from the Kyle Field is processed through the Banff FPSO facilities resulting in lower combined production costs from these fields.

The Company holds a 100% operated working interest in T-block (comprising the Tiffany, Toni and Thelma Fields).

The Company receives tariff revenue from other field owners for the processing of crude oil and natural gas through some of the processing facilities. Opportunities for further long-reach well development on adjacent fields are provided by the existing processing facilities.

During 2008 two production wells were completed at Murchison and one production well was completed at Ninian with an additional well in progress at Ninian at year end. The Company also drilled one water injection well at Ninian and further increased volumes injected in to the Ninian reservoir.

The Company continued with its planned investment in its long-term facilities and infrastructure strategy and successfully carried our maintenance turnarounds at all five installations during the year. With the Murchison turnaround, the Company implemented a new control system which has resulted in improved platform uptime.

In the first quarter 2009, the Company commenced drilling on Deep Banff a high temperature, high pressure, natural gas exploration well. Upon successful discovery the net interest to the Company increases from 18% to 37%. Results are expected in the second quarter of 2009.

OFFSHORE WEST AFRICA

COTE D'IVOIRE

[GRAPHIC OMITTED]

The Company owns interests in two exploration licences offshore Cote d'Ivoire.

The Company has a 58.7% operated interested in the Espoir Field in Block CI-26 which is located in water depths ranging from 100 to 700 meters. Production from East Espoir commenced in 2002 and development drilling of West Espoir was completed in 2008. Crude oil from the East and West Espoir Fields is produced to an FPSO with the associated natural gas delivered onshore through a subsea pipeline for local power generation. Progress on the Facility Upgrade Project to increase capacity of the FPSO continues and is expected to be completed in third quarter 2009.

The Company also has a 58% interest in the Baobab Field, identified in Block CI-40, which is eight kilometers south of the Espoir facilities. Problems with the control of sand and solids production led to five of the ten production wells at Baobab being shut in during 2007. The Company secured a deepwater rig that was mobilized in early second quarter 2008 which enabled work to begin on the restoration of the shut-in production with three wells being onstream by year end. A fourth and final well is expected to be completed in the second quarter of 2009.

To date political unrest which has occurred from time to time in Cote d'Ivoire has had no impact on the Company's operations. The Company has developed contingency plans to continue Cote d'Ivoire operations from a nearby country if the situation warrants such a move.

GABON

[GRAPHIC OMITTED][GRAPHIC OMITTED]

The Company has a permit comprising a 90% operating interest in the production sharing agreement for the block containing the Olowi Field. The field is located about 20 kilometers from the Gabonese coast and in 30 meters water depth. Delays in construction of the FPSO which arrived on location in February 2009, have resulted in first oil being expected in the first half of 2009. Two appraisal wells and two production wells have been drilled and development activity is continuing. It is planned that in total 28 horizontal production wells plus one gas injector well will be drilled. Crude oil production will rely on a gas cap expansion supplemented by re-injection of the produced solution gas. Production is expected to ramp up to a plateau rate of approximately 20,000 bbl/d in 2010.

B. CONVENTIONAL CRUDE OIL, NGLS, AND NATURAL GAS RESERVES

For the year ended December 31, 2008, the Company retained a qualified independent reserves evaluator, Sproule Associates Limited ("Sproule"), to evaluate 100% of the Company's conventional proved, as well as proved and probable crude oil, NGLs and natural gas reserves and prepare Evaluation Reports on these reserves. Conventional crude oil, NGLs and natural gas reserves include all of the Company's light/medium, primary heavy, and thermal heavy crude oil, natural gas, coal bed methane and NGLs reserves. They do not include the Company's oil sands mining reserves. The Company has been granted an exemption from certain of the provisions of National Instrument 51-101 - "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute SEC requirements for certain disclosures required under NI 51-101. There are three principal differences between the two standards. The first is the requirement under NI 51-101 to disclose both proved and proved and probable reserves, as well as the related net present value of future net revenues using forecast prices and costs. The second is in the definition of proved reserves; however, as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material. The third is the requirement to disclose a gross reserve reconciliation (before the consideration of royalties). The Company discloses its conventional crude oil, NGLs, and natural gas reserve reconciliations net of royalties in adherence to SEC requirements.

The Company annually discloses proved conventional reserves and the standardized measure of discounted future net cash flows using year-end constant prices and costs as mandated by the SEC in the supplementary crude oil and natural gas information section of the Company's Annual Report and in its annual Form 40-F filing with the SEC. The Company has elected to provide the net present value of these same conventional proved reserves as well as its conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. Net present values of conventional reserves are based upon discounted cash flows prior to the consideration of income taxes and existing asset abandonment liabilities. Future development costs and associated material well abandonment liabilities have been applied. The Company has also elected to provide both proved, and proved and probable conventional reserves and the net present value of these reserves using forecast prices and costs as additional voluntary information, which is disclosed in this Annual Information Form.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with Sproule to review the qualifications of and procedures used by the evaluator in determining the estimate of the Company's quantities and net present value of remaining conventional crude oil, NGLs and natural gas reserves.

The following tables summarize the evaluations of conventional reserves and estimated net present values of these reserves at December 31, 2008.

THE ESTIMATED NET PRESENT VALUES OF RESERVES CONTAINED IN THE FOLLOWING TABLES

ARE NOT TO BE CONSTRUED AS A REPRESENTATION OF THE FAIR MARKET VALUE OF THE PROPERTIES TO WHICH THEY RELATE. THE ESTIMATED FUTURE NET REVENUES DERIVED FROM THE ASSETS ARE PREPARED PRIOR TO CONSIDERATION OF INCOME TAXES AND EXISTING ASSET ABANDONMENT LIABILITIES. ONLY FUTURE DEVELOPMENT COSTS AND ASSOCIATED FUTURE MATERIAL WELL ABANDONMENT LIABILITIES HAVE BEEN APPLIED. NO INDIRECT COSTS SUCH AS OVERHEAD, INTEREST AND ADMINISTRATIVE EXPENSES HAVE BEEN DEDUCTED FROM THE ESTIMATED FUTURE NET REVENUES. OTHER ASSUMPTIONS AND QUALIFICATIONS RELATING TO COSTS, PRICES FOR FUTURE PRODUCTION AND OTHER MATTERS ARE SUMMARIZED IN THE NOTES TO THE FOLLOWING TABLES. THERE IS NO ASSURANCE THAT THE PRICE AND COST ASSUMPTIONS CONTAINED IN EITHER THE CONSTANT OR FORECAST CASES WILL BE ATTAINED AND VARIANCES COULD BE MATERIAL.

NET CONVENTIONAL CRUDE OIL, NGLS AND NATURAL GAS RESERVES (NET OF ROYALTIES)

	Crude oil & NGLs (mmbbl) Total proved reserves	Total proved & probable reserves	Constant Prices an Total proved
NORTH AMERICA			
Canada	948	1,599	
United States	-	-	
INTERNATIONAL			
United Kingdom	256	399	
Cote d'Ivoire	124	170	
Gabon	18	21	
TOTAL	1,346	2,189	

CONVENTIONAL CRUDE OIL, NGLS AND NATURAL GAS RESERVES

	Crude oil & NGLs (mmbbl) Company gross	Net	Constant Prices an Company
Proved developed reserves	704	632	
Proved undeveloped reserves	766	714	
TOTAL PROVED RESERVES	1,470	1,346	
TOTAL PROVED & PROBABLE RESERVES	2,371	2,189	

ESTIMATED NET PRESENT VALUE

	Constant Prices and Costs		
($ millions)	Undiscounted		Discounted 10%
Proved developed reserves	$	19,328	12,987
Proved undeveloped reserves	$	7,690	2,200
TOTAL PROVED RESERVES	$	27,018	15,187
TOTAL PROVED & PROBABLE RESERVES	$	39,216	19,264

CONVENTIONAL CRUDE OIL, NGLS AND NATURAL GAS RESERVES

	Forecast Price		
	Crude oil & NGLs (mmbbl)		
	Company gross	Net	Com
Proved developed reserves	813	683	
Proved undeveloped reserves	750	604	
TOTAL PROVED RESERVES	1,563	1,287	
TOTAL PROVED & PROBABLE RESERVES	2,430	1,968	

ESTIMATED NET PRESENT VALUES

	Forecast Prices and Cost				
($ millions)	Undiscounted		10%		
Proved developed reserves	$	46,341	$	25,995	$
Proved undeveloped reserves	$	35,554	$	11,992	$
TOTAL PROVED RESERVES	$	81,895	$	37,987	$
TOTAL PROVED & PROBABLE RESERVES	$	130,876	$	52,770	$

NOTES

1. "Company Gross" reserves means the total working interest share of remaining recoverable reserves owned by the Company before consideration of royalties.

2. "Net" reserves mean the Company's gross reserves less all royalties

payable to others plus royalties receivable from others.

3. "Proved developed" reserves were evaluated using SEC standards and can be expected to be recovered through existing wells with existing equipment and operating methods. SEC standards require that these be evaluated using year-end constant prices and costs and be disclosed net of royalties. The Company has also provided these reserves using forecast prices and costs as well as before royalties and their associated net present values as additional voluntary information.

4. "Proved undeveloped" reserves were evaluated using SEC standards and are expected to be recovered from new wells on undrilled acreage, or from existing wells where relatively major expenditures are required for the completion of these wells or for the installation of processing and gathering facilities prior to the production of these reserves. Reserves on undrilled acreage are limited to those drilling units offsetting productive wells that are reasonably certain of production when drilled. SEC standards require that these be evaluated using year-end constant prices and costs and be disclosed net of royalties. The Company has also provided these reserves using forecast prices and costs as well as before royalties and their associated net present values as additional voluntary information.

5. "Proved" reserves were evaluated using SEC standards and are those quantities of crude oil, natural gas and NGLs, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. SEC standards require that these be evaluated using year-end constant prices and costs and be disclosed net of royalties. The Company has also provided these reserves using forecast prices and costs as well as before royalties and their associated net present values as additional voluntary information.

6. "Total Proved and Probable" reserves were evaluated using the COGEH standards of NI 51-101 and are those reserves where there is at least a 50% probability that the quantities actually recovered will equal or exceed the stated values. The Company has elected to disclose proved and probable reserves using both constant prices and costs as well as forecast prices and costs and has disclosed these before and net of royalties and their associated net present values. The calculation of a probable reserves and value component by subtracting the proved reserves from the proved and probable reserves may be subject to immaterial error due to the different standards applied in the determination of each value.

7. Canadian securities legislation and policies permit the disclosure of probable reserves which may not be disclosed in reports filed with the SEC by United States companies. Probable reserves are generally believed to be less likely to be recovered than proved reserves. The reserve estimates, included or incorporated by reference in this Annual Information Form could be materially different from the quantities and values ultimately realized.

8. All values are shown in Canadian dollars.

9. The constant price and cost case assumes that prices in effect at year-end 2008 adjusted for quality and transportation as well as the 2008 costs are held constant over life. The constant price assumptions assume the

continuance of current laws, regulations and operating costs in effect on the date of the Evaluation Report. Product prices have been held constant at the 2008 values shown below. In addition, operating and capital costs have not been increased on an inflationary basis.

The crude oil and natural gas constant prices used in the Evaluation Reports are as follows (based on a foreign exchange rate of US$0.82/C$1.00):

	Natural gas				C		
(Year)	Company average price (C$/mcf)	Henry Hub Louisiana (US$/mmbtu)	AECO (C$/mmbtu)	Huntingdon/ Sumas (C$/mmbtu)	Company average price (C$/bbl)	WTI @ Cushing(1) (US$/bbl)	H 12(degr
2008	6.51	5.63	6.34	7.48	34.51	44.60	

(1) "WTI @ CUSHING" REFERS TO THE PRICE OF WEST TEXAS INTERMEDIATE CRUDE OIL AT CUSHING, OKLAHOMA.
(2) "EDMONTON PAR" REFERS TO THE PRICE OF LIGHT GRAVITY (40(degree) API), LOW SULPHUR CONTENT CRUDE OIL AT EDMONTON, ALBERTA.

10. The forecast price and cost cases assume the continuance of current laws and regulations, and any increases in wellhead selling prices also take inflation into account. Sales prices are based on reference prices as detailed below and adjusted for quality and transportation. Costs are escalated at 2% per year. Future crude oil, NGLs and natural gas price forecasts were based on Sproule's December 31, 2008 crude oil, NGLs and natural gas pricing model.

The Company's weighted average crude oil and NGLs price and the weighted average natural gas price in the 2008 evaluation were $34.51 per barrel and $6.51 per mcf respectively. The crude oil and natural gas forecast prices used in the Evaluation Reports are as follows:

	Natural gas				C		
(Year)	Company average price (C$/mcf)	Henry Hub Louisiana (US$/mmbtu)	AECO (C$/mmbtu)	Huntingdon/ Sumas (C$/mmbtu)	Company average price (C$/bbl)	WTI @ Cushing(1) (US$/bbl)	H 12(degr
2009	6.73	6.30	6.82	6.82	53.07	53.73	
2010	7.46	7.32	7.56	7.56	62.06	63.41	
2011	7.74	7.56	7.84	7.84	68.50	69.53	
2012	8.26	8.49	8.38	8.38	77.12	79.59	
2013	9.07	9.74	9.20	9.20	86.07	92.01	

2014	9.26	9.94	9.41	9.41	88.99	93.85
2015	9.46	10.14	9.62	9.62	90.95	95.72
2016	9.67	10.34	9.83	9.83	94.64	97.64
2017	9.88	10.54	10.05	10.05	98.04	99.59
2018	10.08	10.76	10.27	10.27	99.21	101.58
2019	10.32	10.97	10.50	10.50	100.38	103.61

NOTE: FOREIGN EXCHANGE RATE USED WAS US$0.80/C$1.00 FOR 2009; US$0.85/C$1.00 FOR 2010 AND 2011; US$0.90/C$1.00 FOR 2012; AND US$0.95/C$1.00 FOR 2013 AND BEYOND.

11. Estimated future net revenue from all assets is income derived from the sale of net reserves of crude oil, natural gas and NGLs, less all capital costs, production taxes, and operating costs and before provision for income taxes, administrative overhead costs and existing asset abandonment liabilities.

12. The estimated total development capital costs net to the Company necessary to achieve the estimated future net "proved" and "proved and probable" production revenues are:

	Proved		Prov
($ millions)	Forecast price case	Constant price case	Forecast price cas
2009	1,592	1,589	1,84
2010	1,646	1,613	1,93
2011	1,657	1,590	2,16
2012	883	832	1,40
2013	1,122	1,037	1,70
2014	620	562	81
2015	390	346	56
2016	605	527	66
2017	477	407	83
2018	286	239	54
2019	221	181	30
Thereafter	1,972	1,054	3,42

13. The Evaluation Reports involved data supplied by the Company with respect to quality, heating value and transportation adjustments, interests owned, royalties payable, operating costs and contractual commitments. This data was found by Sproule to be reasonable and no field inspection was conducted.

A report on conventional reserves data by Sproule and a report on oil sands mining reserves data by GLJ are provided in Schedule "A" to this Annual Information Form. A report by the Company's management and directors on crude oil and natural gas disclosure and oil sands mining disclosure is provided in Schedule "B" to this Annual Information Form. The Company does not file estimates of its total crude oil and natural gas reserves or oil sands mining reserves with any U. S. agency or federal authority other than the SEC.

C. RECONCILIATION OF CHANGES IN NET CONVENTIONAL RESERVES

The following table summarizes the changes during the past year in reserves after deduction of royalties payable to others and using constant prices and costs:

	Crude oil & NGLs (mmbbl)				N
	North America	North Sea	Offshore West Africa	Total	North America
PROVED RESERVES					
RESERVES, DEC 31, 2006	887	299	130	1,316	3,705
Extensions & discoveries	30	-	-	30	134
Infill drilling	10	6	-	16	124
Improved recovery	3	-	-	3	8
Property purchases	1	-	-	1	12
Property disposals	-	(3)	-	(3)	-
Production	(77)	(20)	(10)	(107)	(503)
Revisions of prior estimates	66	28	8	102	41
RESERVES, DEC 31, 2007	920	310	128	1,358	3,521
Extensions & discoveries	51	-	-	51	140
Infill drilling	7	6	4	17	46
Improved recovery	10	-	-	10	6
Property purchases	-	-	-	-	77
Property disposals	-	-	-	-	(1)
Production	(76)	(17)	(8)	(101)	(449)
Economic revisions due to prices	28	(81)	8	(45)	(19)
Revisions of prior estimates	8	38	10	56	202
RESERVES, DEC 31, 2008	948	256	142	1,346	3,523
PROVED AND PROBABLE RESERVES					
RESERVES, DEC 31, 2006	1,502	422	195	2,119	4,857
Extensions & discoveries	41	-	-	41	177
Infill drilling	52	6	-	58	163
Improved recovery	4	-	-	4	8
Property purchases	2	6	-	8	17
Property disposals	-	(3)	-	(3)	(1)
Production	(77)	(20)	(10)	(107)	(503)
Revisions of prior estimates	21	(6)	1	16	(116)
RESERVES, DEC 31, 2007	1,545	405	186	2,136	4,602
Extensions & discoveries	76	-	-	76	182
Infill drilling	9	4	-	13	58
Improved recovery	23	-	-	23	8
Property purchases	6	-	-	6	93
Property disposals	-	-	-	-	(6)
Production	(76)	(17)	(8)	(101)	(449)

Economic revisions due to prices	59	(45)	8	22	(27)
Revisions of prior estimates	(43)	52	5	14	158
RESERVES, DEC 31, 2008	1,599	399	191	2,189	4,619

NOTE: Revisions of prior year estimates for 2007 include revisions due to prices.

Information on the Company's conventional crude oil, NGLs and natural gas reserves is provided in accordance with United States FAS 69, "Disclosures About Oil and Gas Producing Activities" in the Company's Form 40-F filed with the SEC and in the Company's 2008 Annual Report under "Supplementary Oil and Gas Information" on pages 101 to 105 and is incorporated herein by reference.

D. CRUDE OIL, NGLS AND NATURAL GAS PRODUCTION

The Company's working interest share of crude oil, NGLs and natural gas production and revenues received for the last three financial years is summarized in the following tables:

	Year Ended Dec 31		
	2008	2007	2006
Daily production, before royalties			
Crude oil and NGLs (bbl/d)	315,667	331,232	331,998
Natural gas (mmcf/d)	1,495	1,668	1,492
Annual production, before royalties			
Crude oil and NGLs (mbbl)	115,534	120,900	121,179
Natural gas (bcf)	547	609	545

NETBACKS
INFORMATION BY QUARTER

	2008 Q1	Q2	Q3	Q4	YEAR ENDED	Q1	Q
AVERAGE DAILY PRODUCTION VOLUMES, BEFORE ROYALTIES							
Crude oil and NGLs							

(bbl/d)	327,217	319,077	306,970	309,570	315,667	327,001	327,4
Natural gas (mmcf/d)	1,538	1,526	1,490	1,427	1,495	1,717	1,7
PRODUCT NETBACKS (1)							
Crude oil and NGLs ($/bbl)							
Sales price (2)	$ 78.99	$ 103.73	$ 102.30	$ 45.81	$ 82.41	$ 51.71	$ 53.
Royalties	8.70	14.82	14.17	4.49	10.48	4.92	5.
Production expenses	14.81	16.39	17.61	16.33	16.26	13.81	15.
NETBACK	$ 55.48	$ 72.52	$ 70.52	$ 24.99	$ 55.67	$ 32.98	$ 33.
Natural gas ($/mcf)							
Sales price (2)	$ 7.77	$ 9.89	$ 8.82	$ 7.03	$ 8.39	$ 7.74	$ 7.
Royalties	1.35	1.86	1.55	1.08	1.46	1.48	1.
Production expenses	1.03	0.94	1.05	1.06	1.02	0.97	0.
NETBACK	$ 5.39	$ 7.09	$ 6.22	$ 4.89	$ 5.91	$ 5.29	$ 5.
CRUDE OIL AND NGLS NETBACKS BY TYPE(1)							
Light/Pelican Lake/NGLs ($/bbl)							
Sales price (2)	$ 89.68	$ 114.69	$ 107.33	$ 53.16	$ 90.88	$ 60.19	$ 64.
Royalties	11.43	14.59	15.84	5.71	11.83	4.89	5.
Production expenses	15.09	16.13	17.18	17.92	16.56	13.85	14.
NETBACK	$ 63.15	$ 83.97	$ 74.30	$ 29.53	$ 62.49	$ 41.45	$ 43.
Heavy crude oil ($/bbl)							
Sales price (2)	$ 67.46	$ 92.55	$ 97.20	$ 38.21	$ 73.62	$ 41.24	$ 41.
Royalties	5.74	15.05	12.47	3.22	9.08	4.96	4.
Production expenses	14.50	16.65	18.05	14.68	15.95	13.76	15.
NETBACK	$ 47.22	$ 60.85	$ 66.68	$ 20.31	$ 48.59	$ 22.52	$ 21.

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

NETBACKS
INFORMATION BY QUARTER

2006			
Q1	Q2	Q3	Q4

AVERAGE DAILY PRODUCTION VOLUMES, BEFORE ROYALTIES				
Crude oil and NGLs (bbl/d)	323,662	338,852	321,665	343,705
Natural gas (mmcf/d)	1,436	1,475	1,437	1,620
PRODUCT NETBACKS(1)				
Crude oil and NGLs ($/bbl)				
Sales price ((2))	$ 43.79	$ 60.05	$ 62.55	$ 47.27
Royalties	3.48	5.14	5.11	4.10
Production expenses	11.33	11.92	13.47	12.32
Netback	$ 28.98	$ 42.99	$ 43.97	$ 30.85
Natural gas ($/mcf)				
Sales price ((2))	$ 8.30	$ 6.16	$ 5.83	$ 6.66
Royalties	1.70	1.11	1.11	1.26
Production expenses	0.80	0.80	0.84	0.86
Netback	$ 5.80	$ 4.25	$ 3.88	$ 4.54
CRUDE OIL AND NGLS NETBACKS BY TYPE(1)				
Light/Pelican Lake/NGLs ($/bbl)				
Sales price ((2))	$ 58.28	$ 69.02	$ 71.65	$ 57.68
Royalties	4.65	5.53	5.39	4.39
Production expenses	11.15	11.18	14.12	12.99
Netback	$ 42.48	$ 52.31	$ 52.14	$ 40.30
Heavy crude oil ($/bbl)				
Sales price ((2))	$ 25.22	$ 50.08	$ 51.38	$ 36.11
Royalties	1.98	4.71	4.76	3.78
Production expenses	11.55	12.73	12.67	11.60
Netback	$ 11.69	$ 32.64	$ 33.95	$ 20.73

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

	2008						
	Q1	Q2	Q3	Q4	YEAR ENDED	Q1	Q2
SEGMENTED							

NORTH AMERICA PRODUCT NETBACKS((1))								
Light/Pelican Lake/NGLs ($/bbl)								
Sales price ((2))	$ 82.25	$ 107.38	$ 102.17	$ 44.21	$ 84.00	$ 54.13	$ 56.06	$
Royalties	16.40	21.68	21.29	8.80	17.20	8.84	9.22	
Production expenses	12.80	13.32	13.17	13.68	13.24	11.74	12.11	
NETBACK	$ 53.05	$ 72.38	$ 67.70	$ 21.73	$ 53.72	$ 33.55	$ 34.73	$
Heavy crude oil ($/bbl)								
Sales price ((2))	$ 67.46	$ 92.55	$ 97.20	$ 38.21	$ 73.62	$ 41.24	$ 41.85	$
Royalties	5.74	15.05	12.47	3.22	9.08	4.96	4.98	
Production expenses	14.50	16.65	18.05	14.68	15.95	13.76	15.12	
NETBACK	$ 47.22	$ 60.85	$ 66.68	$ 20.31	$ 48.59	$ 22.52	$ 21.75	$
Natural gas ($/mcf)								
Sales price ((2))	$ 7.74	$ 9.89	$ 8.76	$ 6.94	$ 8.41	$ 7.79	$ 7.47	$
Royalties	1.36	1.88	1.55	1.09	1.47	1.50	1.11	
Production expenses	1.01	0.98	1.03	1.04	1.00	0.95	0.87	
NETBACK	$ 5.37	$ 7.08	$ 6.18	$ 4.81	$ 5.88	$ 5.34	$ 5.49	$
NORTH SEA PRODUCT NETBACKS((1))								
Light crude oil ($/bbl)								
Sales price ((2))	$ 99.01	$ 129.57	$ 109.82	$ 63.07	$ 100.31	$ 68.83	$ 73.18	$
Royalties	0.91	0.27	0.24	0.12	0.21	0.13	0.13	
Production expenses	22.35	25.61	29.21	28.77	26.29	18.57	22.11	
NETBACK	$ 76.47	$ 103.69	$ 80.37	$ 34.18	$ 73.81	$ 50.13	$ 50.94	$
Natural Gas ($/mcf)								
Sales price ((2))	$ 3.30	$ 4.27	$ 3.65	$ 5.19	$ 4.09	$ 4.49	$ 3.92	$
Royalties	-	-	-	-	-	-	-	
Production expenses	2.33	2.68	3.09	1.96	2.51	2.58	2.26	
NETBACK	$ 0.97	$ 1.59	$ 0.56	$ 3.23	$ 1.58	$ 1.91	$ 1.66	$
OFFSHORE WEST AFRICA PRODUCT NETBACKS((1))								
Light crude oil ($/bbl)								
Sales price ((2))	$ 96.31	$ 114.56	$ 125.71	$ 65.80	$ 97.96	$ 58.60	$ 72.84	$
Royalties	17.43	14.49	26.90	4.71	14.81	3.70	7.12	
Production expenses	8.03	9.79	7.74	14.47	10.29	8.93	7.98	

NETBACK	$ 70.85	$ 90.28	$ 91.07	$ 46.62	$ 72.86	$ 45.97	$ 57.74 $
Natural gas ($/mcf)							
Sales price ((2))	$ 7.89	$ 8.97	$ 11.18	$ 12.54	$ 10.03	$ 5.97	$ 6.22 $
Royalties	1.43	1.13	2.24	1.26	1.52	0.38	0.59
Production expenses	1.25	1.27	1.58	2.51	1.61	1.48	1.10
NETBACK	$ 5.21	$ 6.57	$ 7.36	$ 8.77	$ 6.90	$ 4.11	$ 4.53 $

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Netof transportation and blending costs and excluding risk management activities.

	2006 Q1	Q2	Q3
SEGMENTED			
NORTH AMERICA PRODUCT NETBACKS((1))			
Light/Pelican Lake/NGLs ($/bbl)			
Sales price ((2))	$ 48.83	$ 64.35	$ 65.15 $
Royalties	8.98	10.87	10.86
Production expenses	9.86	9.75	10.81
NETBACK	$ 29.99	$ 43.73	$ 43.48 $
Heavy Crude Oil ($/bbl)			
Sales price ((2))	$ 25.22	$ 50.08	$ 51.38 $
Royalties	1.98	4.71	4.76
Production expenses	11.55	12.73	12.67
NETBACK	$ 11.69	$ 32.64	$ 33.95 $
Natural gas ($/mcf)			
Sales price ((2))	$ 8.39	$ 6.21	$ 5.86 $
Royalties	1.73	1.13	1.12
Production expenses	0.79	0.79	0.83
NETBACK	$ 5.87	$ 4.29	$ 3.91 $
NORTH SEA PRODUCT NETBACKS((1))			
Light crude oil ($/bbl)			
Sales price ((2))	$ 68.05	$ 73.19	$ 78.68 $
Royalties	0.12	0.17	0.11

Production expenses		16.85		17.18		20.28	
NETBACK	$	51.08	$	55.84	$	58.29	$
Natural gas ($/mcf)							
Sales price ((2))	$	2.38	$	2.33	$	2.38	$
Royalties		-		-		-	
Production expenses		1.26		1.47		1.30	
NETBACK	$	1.12	$	0.86	$	1.08	$
OFFSHORE WEST AFRICA PRODUCT NETBACKS((1))							
Light crude oil ($/bbl)							
Sales price ((2))	$	65.23	$	72.97	$	70.59	$
Royalties		1.55		1.87		4.89	
Production expenses		6.08		5.61		7.97	
NETBACK	$	57.60	$	65.49	$	57.73	$
Natural gas ($/mcf)							
Sales price ((2))	$	5.59	$	5.30	$	4.97	$
Royalties		0.13		0.14		0.34	
Production expenses		1.00		0.36		1.39	
NETBACK	$	4.46	$	4.80	$	3.24	$

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

E. NET CAPITAL EXPENDITURES

Costs incurred by the Company in respect of its programs of acquisition and disposition, and exploration and development of crude oil and natural gas properties, are summarized in the following tables. Net capital expenditures do not include non-cash property, plant and equipment additions and disposals.

CAPITAL EXPENDITURES BY YEAR (1)

	Year Ended Dec 31	
($ millions)	2008	2007
Net property acquisitions (dispositions)((2))	336	(39)
Land acquisition and retention	86	95
Seismic evaluations	107	124
Well drilling, completion and equipping	1,664	1,642
Production and related facilities	1,282	1,205
Total net reserve replacement expenditures	3,475	3,027
Horizon Project:		

Phase 1 construction costs	2,732	2,740
Phase 1 operating and capital inventory	87	-
Phase 1 commissioning costs	277	-
Phase 2/3 costs	336	124
Capitalized interest, stock-based compensation and other	480	437
Total Horizon Project ((3))	3,912	3,301
Midstream	9	6
Abandonments ((4))	38	71
Head office	17	20
TOTAL NET CAPITAL EXPENDITURES	7,451	6,425

CAPITAL EXPENDITURES BY QUARTER (1)

($ millions)	Mar 31	2008 Three Months Ended Jun 30	Sep
Net property acquisitions (dispositions) ((2))	$ (8)	$ 263	$
Land acquisition and retention	12	24	
Seismic evaluation	27	18	
Well drilling, completion and equipping	452	286	4
Production and related facilities	319	270	3
Total net reserve replacement expenditures	802	861	8
Horizon Project:			
Phase 1 construction costs	665	875	6
Phase 1 operating and capital inventory	41	14	
Phase 1 commissioning costs	49	34	
Phase 2/3 costs	77	82	
Capitalized interest, stock-based compensation and other	109	247	
Total Horizon Project ((3))	941	1,252	8
Midstream	1	3	
Abandonments ((4))	6	7	
Head office	3	4	
Total net capital expenditures	$ 1,753	$ 2,127	$ 1,

CAPITAL EXPENDITURES BY QUARTER (1)

($ millions)	Mar 31	2007 Three Months Ended Jun 30	Sep

Net property acquisitions (dispositions) ((2))	$ 46	$ 15	$
Land acquisition and retention	29	22	
Seismic evaluation	50	34	
Well drilling, completion and equipping	714	288	2
Production and related facilities	334	243	2
Total net reserve replacement expenditures	1,173	602	5
Horizon Project			
Phase 1 construction costs	674	704	6
Phase 2/3 costs	44	19	
Capitalized interest, stock-based compensation and other	91	118	1
Total Horizon Project ((3))	809	841	8
Midstream	2	-	
Abandonments ((4))	20	13	
Head office	5	4	
Total net capital expenditures	$ 2,009	$ 1,460	$ 1,4

(1) Net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.
(2) Includes business combinations.
(3) Net capital expenditures for the horizon project also include the impact of intersegment eliminations.
(4) Abandonments represent expenditures to settle aro and have been reflected as capital expenditures in this table.

F. Developed and undeveloped acreage

The following table summarizes the Company's working interest holdings in core region developed and undeveloped acreage as at December 31, 2008:

(thousands)	Developed Acreage		Undeveloped Acreage		
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gr
North America					
Alberta	6,249	4,955	10,185	8,675	
British Columbia	1,470	1,100	3,007	2,200	
Saskatchewan	799	578	828	715	
Manitoba	6	6	13	13	
North Sea					
United Kingdom	108	74	314	258	
Offshore West Africa					
Cote d'Ivoire	7	4	95	55	
Gabon	-	-	152	137	

Total	8,639	6,717	14,594	12,053

SELECTED FINANCIAL INFORMATION

The following table summarizes the consolidated financial statements of the Company, which follows the full cost method of accounting for crude oil and natural gas operations:

($ millions, except per common share information)	Year Ended Dec 31 2008	2007
Revenues, before royalties	$ 16,173	$ 12,543
Net earnings	$ 4,985	$ 2,608
Per common share - basic and diluted	$ 9.22	$ 4.84
Adjusted net earnings from operations	$ 3,492	$ 2,406
Per common share - basic and diluted	$ 6.46	$ 4.46
Cash flow from operations	$ 6,969	$ 6,198
Per common share - basic and diluted	$ 12.89	$ 11.49
Total assets	$ 42,650	$ 36,114
Total long-term liabilities	$ 20,856	$ 19,230

	2008 Three Months Ended			
($ millions, except per common share information)	Mar 31	Jun 30	Sep 30	Dec 31
Revenues, before royalties	$ 3,967	$ 5,112	$ 4,583	$ 2,511
Net earnings (loss)	$ 727	$ (347)	$ 2,835	$ 1,770
Per common share - basic and diluted	$ 1.35	$ (0.65)	$ 5.25	$ 3.27

	2007 Three Months Ended			
($ millions, except per common share information)	Mar 31	Jun 30	Sep 30	Dec 31
Revenues, before royalties	$ 3,118	$ 3,152	$ 3,073	$ 3,200
Net earnings	$ 269	$ 841	$ 700	$ 798
Per common share - basic and diluted	$ 0.50	$ 1.56	$ 1.30	$ 1.48

CAPITAL STRUCTURE

COMMON SHARES

The Company is authorized to issue an unlimited number of common shares, without nominal or par value. Holders of common shares are entitled to one vote per share at a meeting of shareholders of Canadian Natural, to receive such dividends as declared by the Board of Directors on the common shares and to receive pro-rata the remaining property and assets of the Company upon its dissolution or winding-up, subject to any rights having priority over the common shares.

PREFERRED SHARES

The Company has no preferred shares outstanding; however, the Company is authorized to issue two hundred thousand (200,000) preferred shares designated as Class 1 Preferred Shares. Holders of preferred shares shall not be entitled as such to receive notice of or to attend any meeting of the shareholders of the Company and shall not be entitled to vote at any such meeting except under certain circumstances as described in the Articles of Amalgamation. Holders of preferred shares are entitled to receive such dividends as and when declared by the Board of Directors in priority to common shares and shall be entitled to receive pro-rata in priority to holders of commons shares the remaining property and assets of Canadian Natural upon its dissolution or winding-up. The Company may redeem or purchase for cancellation at any time all or any part of the then outstanding preferred shares and the holders of the preferred shares shall have the right at any time and from time to time to convert such preferred shares into the common shares of the Company.

CREDIT RATINGS

Credit ratings accorded to the Company's debt securities are not recommendations to purchase, hold or sell the debt securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant, and if any such rating is so revised or withdrawn, we are under no obligation to update this Annual Information Form.

The Company is rated "Baa2" with a stable outlook by Moody's Investors Service ("Moody's"), "BBB" with a stable outlook by Standard & Poor's ("S&P") and "BBB (high)" with a negative trend by DBRS Limited ("DBRS").

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. According to the Moody's rating system, debt securities rated Baa are considered as medium-grade obligations, i.e., they are neither highly protected nor poorly secured. Interest payments and principal security appear adequate for the present, but certain protective elements may be lacking or may be characteristically unreliable over any great length of time. Such securities lack outstanding investment characteristics and in fact have speculative characteristics as well. Moody's applies numerical modifiers 1, 2 and 3 in each generic rating classification from Aa through Caa in its corporate bond rating system. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the issue ranks in the lower end of its generic rating category. A Moody's rating outlook is an opinion regarding the likely direction of a rating over the medium term.

S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the S&P rating system, debt securities rated BBB exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments on the debt securities. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. An S&P rating outlook assesses the potential direction of a long term credit rating over the intermediate term. In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions.

DBRS' credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the DBRS rating system, debt securities rated BBB are of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions. The assignment of a "high" or "low" modifier within each rating category indicates relative standing within such category. The rating trend is DBRS' opinion regarding the outlook for the rating.

MARKET FOR CANADIAN NATURAL RESOURCES LIMITED SECURITIES

The Company's common shares are listed and posted for trading on Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") under the symbol CNQ.

2008 Monthly Historical Trading on Toronto Stock Exchange

Month	High	Low	Close	Volume Traded
January	$ 75.99	$ 58.88	$ 64.21	44,123,518
February	$ 76.00	$ 60.17	$ 73.76	48,238,701
March	$ 76.80	$ 64.00	$ 70.27	42,059,186
April	$ 88.36	$ 68.08	$ 85.55	44,070,800
May	$ 106.87	$ 81.50	$ 97.24	50,814,542
June	$ 111.30	$ 94.73	$ 100.84	50,132,584
July	$ 104.83	$ 76.30	$ 80.01	61,435,116
August	$ 91.50	$ 73.89	$ 90.64	50,849,698
September	$ 89.60	$ 64.40	$ 73.00	74,621,067
October	$ 72.89	$ 41.40	$ 60.82	82,264,616
November	$ 64.05	$ 34.19	$ 52.00	72,013,144
December	$ 49.23	$ 36.75	$ 48.75	59,114,946

On January 20, 2006, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of TSX and the NYSE, commencing January 24, 2006 and ending January 23, 2007, to purchase for cancellation up to 26,852,545 common shares of the Company, being 5% of the 537,050,902 common shares of the Company outstanding on January 17, 2006. Under this program, the Company purchased a total of 485,000 common shares for cancellation at a weighted average purchase price of $57.29 for each common share purchased, $57.33 after costs.

On January 22, 2007, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of TSX and the NYSE, commencing January 24, 2007 and ending January 23, 2008, to purchase for cancellation up to 26,941,730 common shares of the Company, being 5% of the 538,834,606 common shares of the Company outstanding on January 15, 2007. No shares were purchased under the program.

DIVIDEND HISTORY

The dividend policy of the Company undergoes a periodic review by the Board of Directors and is subject to change at any time depending upon the earnings of the Company, its financial requirements and other factors existing at the time. Prior to 2001, dividends had not been paid on the common shares of the Company. On January 17, 2001 the Board of Directors approved a dividend policy for the payment of regular quarterly dividends. Dividends have been paid on the first day of January, April, July and October of each year since 2001.

The following table shows the aggregate amount of the cash dividends declared per common share of the Company and accrued in each of its last three years ended December 31.

	2008	2007	2006
Cash dividends declared per common share	$ 0.40	$ 0.34	$ 0.30

In February 2009 the Board of Directors approved a 5% increase in the 2008 quarterly dividend from $0.10 per common share to $0.105 per common share, effective with the April 1, 2009 payment.

TRANSFER AGENTS AND REGISTRAR

The Company's transfer agent and registrar for its common shares is Computershare Trust Company of Canada in the cities of Calgary and Toronto and Computershare Shareholder Services, Inc. in the city of New York. The registers for transfers of the Company's common shares are maintained by Computershare Trust Company of Canada.

DIRECTORS AND OFFICERS

The names, municipalities of residence, offices held with the Company and principal occupations of the directors and officers of the Company are set forth below. Further detail on the Directors and Named Executive Officers are found in the Company's Management Proxy Circular dated March 18, 2009.

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Catherine M. Best, FCA Calgary, Alberta Canada	Director (2)(4) (age 55)	Interim Chief Financial Officer of Services since 2008 when the Al consolidated all of the health regions under one board. Executive Vice-Presiden and Chief Financial Officer of the Cal

		(fully integrated publicly funded health 2002 to 2008; has served continuously as Company since November 2003. Current board of directors of Enbridge Income Plus Income Fund and is a volunteer m Committee of the Calgary Exhibition and
N. Murray Edwards Calgary/Banff, Alberta Canada	Vice-Chairman and Director (3) (age 49)	President, Edco Financial Holdings management and consulting company continuously as a director of the Compa 1988. Currently is Chairman and servi directors of Ensign Energy Services Aerospace Corporation.
Honourable Gary A. Filmon, P.C., O.M. Winnipeg, Manitoba Canada	Director (1)(2) (age 66)	Consultant, The Exchange Group (bus firm). Has served continuously as a Company since February 2006. Current board of directors of MTS Allstream Inc Income Trust, Exchange Industrial Incom West Capital Inc. and FWS Construction Chair of Canada's Security and Int Committee.
Ambassador Gordon D. Giffin Atlanta, Georgia USA	Director (1)(2) (age 59)	Senior Partner, McKenna Long & Aldrid since May 2001. Has served continuously the Company since May 2002. Currentl board of directors of Canadian National Canadian Imperial Bank of Commerce, Savings Corp., and Transalta Corporation
John G. Langille Calgary, Alberta Canada	Vice-Chairman and Director (age 63)	Officer of the Company. Has served director of the Company since June 1982.
Steve W. Laut Calgary, Alberta Canada	President and Chief Operating Officer and Director (age 51)	Officer of the Company. Has served director of the Company since August 200
Keith A.J. MacPhail Calgary, Alberta Canada	Director (3)(5) (age 52)	Chairman and Chief Executive Officer, Trust (oil and gas energy trust) since Chairman, NuVista Energy Ltd. (a exploration, development and producti July 2003. Has served continuously as Company since October 1993. Currently se of directors of Bonavista Energy Trust Ltd.
Allan P. Markin, O.C. Calgary, Alberta Canada	Chairman and Director (5) (age 63)	Chairman of the Company. Has served director of the Company since January 19

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Norman F. McIntyre Calgary, Alberta Canada	Director (3)(4)(5) (age 63)	Independent businessman. Prior t Vice-President, Petro-Canada from 199 recently President, Petro-Canada 2002 t continuously as a director of the Compan Currently is Chairman and is serving directors of Petro Andina Resources Inc.
Frank J. McKenna, P.C., O.C., O.N.B., Q.C. Cap Pele, New Brunswick Canada	Director (1)(4) (age 61)	Deputy Chair, TD Bank Financial services). Counsel to Atlantic Canada Cooper from 1998 to 2005, and most Ambassador to the United States from 20 served continuously as a director of t August 2006. Currently serving on the ofBrookfield Asset Management Inc.
James S. Palmer, C.M., A.O.E., Q.C. Calgary, Alberta Canada	Director (3)(4)(5) (age 80)	Chairman and a Partner of Burnet, Duck (law firm). Has served continuously as Company since May 1997. Currently servi directors of Magellan Aerospace Co Director Emeritus of Frontier Oil Corpor
Dr. Eldon R. Smith, O.C., M.D. Calgary, Alberta Canada	Director (4)(5) (age 69)	President of Eldon R. Smith & Associates health care consulting company), and E and Former Dean, Faculty of Medicin Calgary. Has served continuously as a Company since May 1997. Currently servi directors of Vasogen Inc., Aston Hi Ventripoint Diagnostics Inc.
David A. Tuer Calgary, Alberta Canada	Director (1)(2)(3) (age 59)	Vice-Chairman and Chief Executive Offic Energy Ltd. (private oil and gas expl Chairman, Calgary Health Region from Executive Vice-Chairman BA Energy Inc. February 2008 when it was acquired by i Value Creations Inc. through a Plan of which until recently was engaged in building and operations of a merchant in Northern Alberta for the purpose of and heavy oil feedstock into high-qua Prior thereto President, CEO and a d Resources Inc. from January 2003 to Marc continuously as a director of the Compa Currently serving on the board of dire Resources Trust, Xtreme Coil Drilling Phoenix Resources and Altalink Manageme limited partnership.
Real M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 58)	Officer of the Company.
Real J. H. Doucet Calgary, Alberta Canada	Senior Vice-President, Oil Sands (age 56)	Officer of the Company.
Allen M. Knight Calgary, Alberta Canada	Senior Vice-President, International & Corporate Development	Officer of the Company.

	(age 59)	
Tim S. McKay Calgary, Alberta Canada	Senior Vice-President, Operations (age 47)	Officer of the Company.

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Douglas A. Proll Calgary, Alberta Canada	Chief Financial Officer and Senior Vice-President, Finance (age 58)	Officer of the Company.
Lyle G. Stevens Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 54)	Officer of the Company.
Jeffrey W. Wilson Calgary, Alberta Canada	Senior Vice-President, Exploration (age 56)	Officer of the Company.
Jeffrey J. Bergeson Calgary, Alberta Canada	Vice-President, Exploitation West (age 52)	Officer of the Company since May 200 Exploitation Manager of the Company.
Corey B. Bieber Calgary, Alberta Canada	Vice-President, Finance and Investor Relations (age 45)	Officer of the Company since April 200 Director, Investor Relations of the 2002 to April 2005 and most recentl Investor Relations April 2005 to Februar
Mary-Jo E. Case Calgary, Alberta Canada	Vice-President, Land (age 50)	Officer of the Company.
William R. Clapperton Calgary, Alberta Canada	Vice-President, Regulatory, Stakeholder and Environmental Affairs (age 46)	Officer of the Company.
James F. Corson Calgary, Alberta Canada	Vice-President, Human Resources, Horizon (age 58)	Officer of the Company since January 20 Vice-President, Human Resources of Qat from March 1997 to July 2005 and most Human Resources and Stakeholder Relati from July 2005 to 2007.
Randall S. Davis Calgary, Alberta Canada	Vice-President, Finance & Accounting (age 42)	Officer of the Company since July 200 Financial Controller of the Company July 2004 and most recently Vice-Pr Accounting and Controls July 2004 to Feb
Allan E. Frankiw	Vice-President,	Officer of the Company since March 200

Calgary, Alberta Canada	Production, Central (age 52)	Manager Midstream for Anadarko Canada November 1998 to March 2005, Manag Construction for Anadarko Canada Corpo 2005 to November 2006, and most re Manager, Edson of the Company from Nove 2007.
Peter J. Janson Calgary, Alberta Canada	Vice-President, Engineering Integration (age 51)	Officer of the Company since December 20 Director, Engineering Integration of November 2002 to December 2004.
Philip A. Keele Calgary, Alberta Canada	Vice-President, Mining, Horizon Oil Sands Project (age 49)	Officer of the Company since December 20 Director, Mine Engineering of the Comp 2002 to December 2004.

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Cameron S. Kramer Calgary, Alberta Canada	Vice-President, Development Operations (age 41)	Officer of the Company.
Ronald K. Laing Calgary, Alberta Canada	Vice-President, Commercial Operations (age 39)	Officer of the Company since March 200 Commercial Operations Advisor of t November 2003 to April 2004, and most Commercial Operations of the Company March 2009.
Leon Miura Calgary, Alberta Canada	Vice-President, Horizon Major Projects (age 54)	Officer of the Company.
Reno G. Laseur Fort McMurray, Alberta Canada	Vice-President, Upgrading (age 53)	Officer of the Company since August 200 Operations Manager, Upgrading of the 2002 to October 2007, and most rec Director, Upgrading of the Company fr August 2008.
S. John Parr Calgary, Alberta Canada	Vice-President, Production, East (age 47)	Officer of the Company since April 20 Production Manager, Heavy Oil of th e 2002 to April 2004.
David A. Payne Calgary, Alberta Canada	Vice-President, Exploitation, Central (age 47)	Officer of the Company since October 20 Exploitation Manager, Technical Proje from August 2003 to October 2004, Exploitation, West from October 2004 t most recently Vice-President, Exploitat 2007 to February 2008.
William R. Peterson Calgary, Alberta Canada	Vice-President, Production, West (age 42)	Officer of the Company since April 200 Production Manager, West of the Company.

Timothy G. Reed Calgary, Alberta Canada	Vice-President, Human Resources (age 52)	Officer of the Company since January 20 Manager, Human Resources of the Compan most recently Director, Human Resourc 2007.
Joy P. Romero Calgary, Alberta Canada	Vice President, Bitumen Production (age 52)	Officer of the Company since March 200 Director, Bitumen Production Process o September 2002 to March 2008.
Sheldon L. Schroeder Fort McMurray, Alberta Canada	Vice-President, Project Control (age 41)	Officer of the Company since April 200 Director, Project Control of the Compa 2002 to April 2004.
Kendall W. Stagg Calgary, Alberta Canada	Vice-President, Exploration, West (age 47)	Officer of the Company since October 20 Manager Exploration, B. C. of the Comp to September 2004.
Scott G. Stauth Calgary, Alberta Canada	Vice-President, Field Operations (age 51)	Officer of the Company since November 20 Manager, Eastern Field Operations of 2003 to November 2006.
Stephen C. Suche Calgary, Alberta Canada	Vice-President, Information and Corporate Services (age 49)	Officer of the Company since July 200 Manager Information and Corporate Servi January 2000 to July 2006.

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Domenic Torriero Calgary, Alberta Canada	Vice-President, Exploration, Central (age 44)	Officer of the Company since November 20 Vice-President Geology and Geophysi Resources Limited January 1999 to Ma recently Exploration Manager of the Com November 2006.
Grant M. Williams Calgary, Alberta Canada	Vice-President, Exploration, East (age 51)	Officer of the Company since March 200 Manager, Exploration Heavy Oil of the 2003 to April 2007.
Daryl G. Youck Calgary, Alberta Canada	Vice-President, Exploitation, East (age 40)	Officer of the Company since February 20 Manager, Exploitation of the Compa February 2008.
Lynn M. Zeidler Calgary, Alberta Canada	Vice-President, Utilities and Services (age 52)	Officer of the Company.
Bruce E. McGrath Calgary, Alberta Canada	Corporate Secretary (age 59)	Officer of the Company.

(1) Member of the nominating and corporate governance committee
(2) member of the audit committee

(3) member of the reserves committee
(4) member of the compensation committee
(5) member of the health, safety, and environmental committee

All directors stand for election at each Annual General Meeting of Canadian Natural shareholders. All of the current directors were elected to the Board at the last annual general meeting of shareholders held on May 8, 2008.

As at December 31, 2008, the directors and officers of the Company, as a group, beneficially owned or controlled or directed, directly or indirectly, in the aggregate, approximately 4% of the total outstanding common shares (approximately 6% after the exercise of options held by them pursuant to the Company's stock option plan).

CONFLICTS OF INTEREST

There are potential conflicts of interest to which the directors and officers of the Company may become subject in connection with the operations of the Company. Some of the directors and officers have been and will continue to be engaged in the identification and evaluation of businesses and assets with a view to potential acquisition of interests on their own behalf and on behalf of other corporations. Situations may arise where the directors and officers will be in direct competition with the Company. Conflicts, if any, will be subject to the procedures and remedies under the BUSINESS CORPORATIONS ACT (Alberta).

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer or principal shareholder of Canadian Natural, or associate or affiliate of those persons, has any material interest, direct or indirect, in any transaction within the last three years that has materially affected or is reasonably expected to materially affect the Company.

AUDIT COMMITTEE INFORMATION

AUDIT COMMITTEE MEMBERS

The Audit Committee of the Board of Directors of the Company is comprised of Ms. C. M. Best, Chair, Messrs. G. A. Filmon, G. D. Giffin and D. A. Tuer each of whom is independent and financially literate as those terms are defined under Canadian securities regulations National Instrument 52-110 and the NYSE listing standards as they pertain to audit committees of listed issuers. The education and experience of each member of the Audit Committee relevant to their responsibilities as an Audit Committee member is described below.

Ms. C. M. Best is a chartered accountant with 20 years experience as a staff member and partner of an international public accounting firm. During her tenure she was responsible for direct oversight and supervision of a large staff of auditors conducting audits of the financial reporting of significant publicly traded entities, many of which were oil and gas companies. This oversight and supervision required Ms. C. M. Best to maintain a current understanding of generally accepted accounting principles, and be able to assess their application in each of her clients. It also required an understanding of internal controls and financial reporting processes and procedures.

Honourable G. A. Filmon holds both a Bachelor of Science degree and a Master of Science degree in Civil Engineering. He was Premier of the Province of Manitoba for several years and during that time chaired the Treasury Board for a period of five years. He was President of Success Commercial College for 11 years and is currently a business management consultant. Mr. G. A. Filmon is a director of other public companies and is an active member of other audit committees, one of which he chairs.

Ambassador G. D. Giffin's education and experience relevant to the performance of his responsibilities as an audit committee member is derived from a thirty-year law practice involving complex accounting and audit-related issues associated with complicated commercial transactions and disputes. He has developed extensive practical experience and an understanding of internal controls and procedures for financial reporting from his service on audit committees for several publicly traded issuers and continues pursuit of extensive professional reading and study on related subjects.

Mr. D. A. Tuer's education and experience relevant to the performance of his responsibilities as an audit committee member is derived from professional training and a business career as a chief executive officer in a large publicly traded company which provided experience in analyzing and evaluating financial statements and supervising persons engaged in the preparation, analysis and evaluation of financial statements of publicly traded companies. He has gained an understanding of internal controls and procedures for financial reporting through oversight of those functions, and the understanding of Audit Committee functions through his years of chief executive involvement.

AUDITOR SERVICE FEES

The Audit Committee of the Board of Directors in 2008 approved specified audit and non-audit services to be performed by PricewaterhouseCoopers LLP ("PwC"). The services provided include: (i) the annual audit of the Corporation's internal controls and December 31, 2008 consolidated financial statements included in the Annual Information Form and Form 40-F, reviews of the Corporation's quarterly unaudited Consolidated Financial Statements, audits of certain of the Corporation's subsidiary companies' annual financial statements as well as other audit services provided in connection with statutory and regulatory filings; (ii) audit related services including debt covenant compliance and Crown Royalty Statements; (iii) tax related services related to expatriate personal tax and compliance as well as other corporate tax return matters; and (iv) non-audit services related to accessing resource materials through PwC's accounting literature library.

Fees accrued to PwC are shown in the table below.

Auditor service	2008	2007
Audit fees	$ 2,685,800	$ 2,729,315

Audit related fees	156,300	164,000
Tax related fees	91,500	154,459
All other fees	9,500	9,440
	$ 2,943,100	$ 3,057,214

The Charter of the Audit Committee of the Company is attached as Schedule "C" to this Annual Information Form.

LEGAL PROCEEDINGS

From time to time, Canadian Natural is the subject of litigation arising out of the Company's operations. Damages claimed under such litigation may be material or may be indeterminate and the outcome of such litigation may materially impact the Company's financial condition or results of operations. While the Company assesses the merits of each lawsuit and defends itself accordingly, the Company may be required to incur significant expenses or devote significant resources to defend itself against such litigation. The claims that have been made to date are not currently expected to have a material impact on the Company's financial position.

MATERIAL CONTRACTS

Other than contracts entered into in the ordinary course of business, the Company has not entered into any material contracts in the most recently completed financial year nor has it entered into any material contracts before the most recently completed financial year and which are still in effect.

INTERESTS OF EXPERTS

The Company's auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditors' report dated March 4, 2009 in respect of the Company's consolidated financial statements with accompanying notes as at and for the three years ended December 31, 2008 and the Company's internal control over financial reporting as at December 31, 2008. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules of the US Securities and Exchange Commission.

Based on information provided by the relevant persons or companies, there are beneficial interests, direct or indirect, in less than 1% of the Company's securities or property or securities or property of our associates or affiliates held by Sproule Associates Limited or GLJ Petroleum Consultants Ltd. or any partners, employees or consultants of such independent reserves evaluators who participated in and who were in a position to directly influence the preparation of the relevant report, or any such person who, at the time of the preparation of the report was in a position to directly influence the outcome of the preparation of the report.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on the SEDAR website at WWW.SEDAR.COM.

Additional information including Directors' and Executive Officers' remuneration and indebtedness, Director nominees standing for re-election, principal holders of the Company's securities, options to purchase the Company's securities and interest of insiders in material transactions is contained in the Company's Notice of Annual General Meeting and Information Circular dated March 18, 2009 in connection with the Annual General Meeting of Shareholders of Canadian Natural to be held on May 7, 2009 which information is incorporated herein by reference. Additional financial information and discussion of the affairs of the Company and the business environment in which the Company operates is provided in the Company's Management Discussion and Analysis, comparative Consolidated Financial Statements and Supplementary Oil & Gas Information for the most recently completed fiscal year ended December 31, 2008 found on pages 40 to 73, 74 to 100 and 101 to 105 respectively, of the 2008 Annual Report to the Shareholders, which information is incorporated herein by reference.

For additional copies of this Annual Information Form, please contact:

Corporate Secretary of the Corporation at:
2500, 855 - 2nd Street S.W.
Calgary, Alberta T2P 4J8

SCHEDULE "A"
FORM 51-101F2

REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

REPORT ON RESERVES DATA

To the Board of Directors of Canadian Natural Resources Limited (the "Corporation"):

1. We have evaluated the Corporation's reserves data as at December 31, 2008. The reserves data consist of the following:

(a) (i) proved conventional crude oil, NGLs and natural gas reserve quantities estimated as at December 31, 2008 using constant prices and costs;

(ii) the related future net revenue; and

(iii) the related standardized measure calculation for proved conventional crude oil, NGL and natural gas reserve quantities.

(b) (i) both proved, and proved and probable conventional crude oil,NGL and natural gas reserve quantities estimated as at December 31, 2008 using forecast prices and costs;

(ii) the related future net revenue; and,

(c) (i) both proved, and proved and probable synthetic crude oil reserves and associated bitumen quantities relating to surface mineable oil sands operations estimated as at December 31, 2008.

2. The reserves data are the responsibility of the Corporation'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) with the necessary modifications to reflect definitions and standards under the U.S. Financial Accounting Standards Board policies (the "FASB Standards") and the legal requirements of the U.S. Securities and Exchange Commission ("SEC Requirements").

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 as outlined in the COGE Handbook, the FASB Standards and the SEC Requirements.

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 Corporation evaluated by us for the year ended December 31, 2008 and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's management and board of directors:

INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR	DESCRIPTION AND PREPARATION DATE OF EVALUATION REPORT	LOCATION OF RESERVES (COUNTRY OR FOREIGN GEOGRAPHIC AREA)	NET PRESENT V (BEFORE INCOM ($MILLIONS)	
			AUDITED	E
Sproule Associates Limited	Sproule Evaluated the P&NG Reserves as reported February 17th, 2009.	Canada and USA	$ 0	
Sproule Associates Limited	Sproule Evaluated the P&NG Reserves as reported February 17th, 2009.	United Kingdom and Offshore West Africa	$ 0	
TOTALS			$ 0	

In addition, both proved, and proved and probable reserves have been evaluated for oil sands mining properties located in Canada. The Horizon Project reserves were evaluated as at December 31, 2008. GLJ Petroleum

Consultants ("GLJ"), an independent qualified reserves evaluator, was retained by the Reserves Committee of Canadian Natural's Board of Directors to evaluate reserves associated with the Horizon Project incorporating both the mining and upgrading projects. These reserves were evaluated under SEC Industry Guide 7 and are disclosed separately from the Corporation's conventional crude oil and natural gas activities.

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 as modified by the FASB Standards and SEC requirements. 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, CANADA, FEBRUARY 25, 2009

Original Signed By:

Harry J. Helwerda, P.Eng.,
Executive Vice-President

Original Signed By:

Doug Ho, P.Eng.
Vice-President, Unconventional

Original Signed By:

R. Keith MacLeod, P.Eng. President

GLJ PETROLEUM CONSULTANTS, CALGARY, ALBERTA, CANADA, FEBRUARY 24, 2009

Original Signed By:

James H. Willmon, P.Eng.
Vice-President

SCHEDULE "B"

REPORT OF
MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Canadian Natural Resources Limited (the "Corporation") is responsible for the preparation and disclosure of information with respect to the Corporation's oil, gas and surface mineable oil sands activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved conventional crude oil, NGLs and natural gas reserve quantities estimated as at December 31, 2008 using constant prices and costs;

(ii) the related future net revenue; and

(iii) the related standardized measure calculation for proved conventional crude oil, NGL and natural gas reserve quantities.

(b) (i) both proved, and proved and probable conventional crude oil, NGL and natural gas reserve quantities estimated as at December 31, 2008 using forecast prices and costs;

(ii) the related future net revenue; and,

(c) (i) both proved, and proved and probable synthetic crude oil reserves and associated bitumen quantities relating to surface mineable oil sands operations estimated as at December 31, 2008.

Sproule Associates Limited and GLJ Petroleum Consultants, both 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 (the "Reserves Committee") of the board of directors (the "Board of Directors") of the Corporation has:

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

(b) met with each of the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation and in the event of a proposal to change the independent qualified reserves evaluators, to inquire whether there had been disputes between the previous independent qualified reserves evaluators and management; 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, gas and surface mineable oil sands activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil, gas and surface mineable oil sands information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments 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.

Original Signed By:

/s/ Steve W. Laut

Steve W. Laut
President and Chief Operating Officer

Original Signed By:

/s/ Douglas A. Proll

Douglas A. Proll
Chief Financial Officer and Senior Vice President, Finance

Original Signed By:

/s/ David A. Tuer

David A. Tuer
Independent Director and Chair of the Reserve Committee

Original Signed By:

/s/ Norman F. McIntyre

Norman F. McIntyre
Independent Director and Member of the Reserve Committee

Dated this 3rd day of March, 2009
Calgary, Alberta

SCHEDULE "C"

CANADIAN NATURAL RESOURCES LIMITED
(THE "CORPORATION")

CHARTER OF THE AUDIT COMMITTEE OF THE BOARD OF DIRECTORS

I. Audit Committee Purpose

The Audit Committee is appointed by the Board of Directors (the "Board") to assist the Board in fulfilling its responsibility for the stewardship of the Corporation in overseeing the business and affairs of the Corporation. Although the Audit Committee has the powers and responsibilities set forth in this Charter, the role of the Audit Committee is oversight. The Audit Committee's primary duties and responsibilities are to:

1. ensure that the Corporation's management implemented an effective system of internal controls over financial reporting;

2. monitor and oversee the integrity of the Corporation's financial statements, financial reporting processes and systems of internal controls regarding financial, accounting and compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and disclosure of material facts;

3. select and recommend for appointment by the shareholders, the Corporation's independent auditors, pre-approve all audit and non-audit services to be provided to the Corporation by the Corporation's independent auditors consistent with all applicable laws, and establish the fees and other compensation to be paid to the independent auditors;

4. monitor the independence, qualifications and performance of the Corporation's independent auditors and oversee the audit of the Corporation's financial statements;

5. monitor the performance of the internal audit function;

6. establish procedures for the receipt, retention, response to and treatment of complaints, including confidential, anonymous submissions by the Corporation's employees, regarding accounting, internal controls or auditing matters; and,

7. provide an avenue of communication among the independent auditors, management, the internal auditing function and the Board.

II. Audit Committee Composition, Procedures and Organization

1. The Audit Committee shall consist of at least three (3) directors as determined by the Board, each of whom shall be independent, non-executive directors, free from any relationship that would interfere with the exercise of his or her independent judgment. Audit Committee members shall meet the independence and experience requirements of the regulatory bodies to which the Corporation is subject to. All members of the Audit Committee shall have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements at the time of their

appointment to the Audit Committee. At least one member of the Audit Committee shall have accounting or related financial management expertise and qualify as a "financial expert" or similar designation in accordance with the requirements of the regulatory bodies to which the Corporation may be subject to.

2. The Board at its organizational meeting held in conjunction with each annual general meeting of the shareholders shall appoint the members of the Audit Committee for the ensuing year. The Board may at any time remove or replace any member of the Audit Committee and may fill any vacancy in the Audit Committee.

3. The Board shall appoint a member of the Audit Committee as chair of the Audit Committee. If an Audit Committee Chair is not designated by the Board, or is not present at a meeting of the Audit Committee, the members of the Audit Committee may designate a chair by majority vote of the Audit Committee membership.

4. The Secretary or the Assistant Secretary of the Corporation shall be secretary of the Audit Committee unless the Audit Committee appoints a secretary of the Audit Committee.

5. The quorum for meetings shall be one half (or where one half of the members of the Audit Committee is not a whole number, the whole number which is closest to and less than one half) of the members of the Audit Committee subject to a minimum of two members of the Audit Committee present in person or by telephone or other telecommunications device that permits all persons participating in the meeting to speak and to hear each other.

6. Meetings of the Audit Committee shall be conducted as follows:

   (a) the Audit Committee shall meet at least four (4) times annually at such times and at such locations as may be requested by the Chair of the Audit Committee;

   (b) the Audit Committee shall meet privately in executive sessions at each meeting with management, the manager of internal auditing, the independent auditors, and as a committee to discuss any matters that the Audit Committee or each of these groups believe should be discussed.

7. The independent auditors and internal auditors shall have a direct line of communication to the Audit Committee through its chair and may bypass management if deemed necessary. Any employee may bring before the Audit Committee directly and may bypass management if deemed necessary any matter involving questionable, illegal or improper financial practices or transactions.

III. Audit Committee Duties and Responsibilities

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

   a. 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;

b. to establish and maintain a direct line of communication with the Corporation's internal auditors and independent auditors and assess their performance;

c. to ensure that the management of the Corporation has implemented and is maintaining an effective system of internal controls over financial reporting;

d. to report regularly to the Board on the fulfillment of its duties and responsibilities; and,

e. to review annually the Audit Committee Charter and recommend any changes to the Nominating and Corporate Governance Committee for approval by the Board.

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

a. to select and recommend to the Board of Directors for appointment by the shareholders, the Corporation's independent auditors, review the independence and monitor the performance of the independent auditors and approve any discharge of auditors when circumstances warrant;

b. to approve the fees and other significant compensation to be paid to the independent auditors, scope and timing of the audit and other related services rendered by the independent auditors;

c. to review and discuss with management and the independent auditors prior to the annual audit the independent auditor's annual audit plan, including scope, staffing, locations and reliance upon management and internal audit department and oversee the audit of the Corporation's financial statements;

d. to pre-approve all proposed non-audit services to be provided by the independent auditors except those non-audit services prohibited by legislation;

e. on an annual basis, obtain and review a report by the independent auditors describing (i) the independent auditor's internal quality control procedures; (ii) any material issues raised by the most recent quality-control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the firm; and, (iii) any steps taken to address any such issues arising from the review, inquiry or investigation, and , receive a written statement from the independent auditors outlining all significant relationships they have with the Corporation that could impair the auditor's independence. The Corporation's independent auditors may not be engaged to perform prohibited activities under the Sarbanes-Oxley Act of 2002 or the rules of the Public Company Accounting Oversight Board or other regulatory bodies, which the Corporation is governed by;

f. to review and discuss with the independent auditors, upon completion of their audit and prior to the filing or releasing annual financial statements:

   (i) contents of their report, including :

      (a) all critical accounting policies and practices used;

      (b) all alternative treatments of financial information within GAAP that have been discussed with management, ramifications of the use of such treatments and the treatment preferred by the independent auditor;

      (c) other material written communications between the independent auditor and management;

   (ii) scope and quality of the audit work performed;

   (iii) adequacy of the Corporation's financial and auditing personnel;

   (iv) cooperation received from the Corporation's personnel during the audit;

   (v) internal resources used;

   (vi) significant transactions outside of the normal business of the Corporation;

   (vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems;

   (viii) the non-audit services provided by the independent auditors; and,

   (ix) consider the independent auditor's judgments about the quality and appropriateness of the Corporation's accounting principles and critical accounting estimates as applied in its financial reporting.

g. to review and approve a report to shareholders as required, to be included in the Corporation's Information Circular and Proxy Statement, disclosing any non-audit services approved by the Audit Committee.

h. to review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former independent auditor of the Corporation.

3. The duties and responsibilities of the Audit Committee as they relate to the internal auditors shall be as follows:

   a. to review the budget, internal audit function with respect to the organization structure, staffing, effectiveness and qualifications of the Corporation's internal audit department;

b. to review the internal audit plan; and

c. to review significant internal audit findings and recommendations together with management's response and follow-up thereto.

4. The duties and responsibilities of the Audit Committee as they relate to the internal control procedures of the Corporation shall be as follows:

a. 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 internal auditing, insurance, accounting, information services and systems and financial controls, management reporting (including financial reporting) and risk management;

b. to review any unresolved issues between management and the independent auditors that could affect the financial reporting or internal controls of the Corporation; and

c. to periodically review the extent to which recommendations made by the internal audit staff or by the independent auditors have been implemented.

5. Other duties and responsibilities of the Audit Committee shall be as follows:

a. to review and discuss with management, the internal audit group and the independent auditors, the Corporation's unaudited quarterly consolidated financial statements and related Management Discussion & Analysis including the impact of unusual items and changes in accounting principles and estimates, the earnings press releases before disclosure to the public and report to the Board with respect thereto;

b. to review and discuss with management, the internal audit group and the independent auditors, the Corporation's audited annual consolidated financial statements and related Management Discussion & Analysis including the impact of unusual items and changes in accounting principles and estimates, the earnings press releases before disclosure to the public and report to the Board with respect thereto;

c. to ensure adequate procedures are in place for the review of the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements, other than the quarterly and annual earnings press releases, and periodically assess the adequacy of those procedures;

d. to review management's report on 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;

e. to review with management, the independent auditors and if necessary with legal counsel, any litigation, claim or other contingency, including tax assessments that could have a material affect upon the financial position or operating results of the Corporation and the manner in which such matters have been disclosed in the consolidated financial statements;

f. to establish procedures for:

(i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

g. to co-ordinate meetings with the Reserves Committee of the Corporation, the Corporation's senior engineering management, independent evaluating engineers and auditors as required and consider such further inquiries as are necessary to approve the consolidated financial statements;

h. to develop a calendar of activities to be undertaken by the Audit Committee for each ensuing year and to submit the calendar in the appropriate format to the Board following each annual general meeting of shareholders;

i. to perform any other activities consistent with this Charter, the Corporation's By-laws and governing law, as the Audit Committee or the Board deems necessary or appropriate; and,

j. to maintain minutes of meetings and to report on a regular basis to the Board on significant results of the foregoing activities.

The Audit Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to the independent auditors as well as officers and employees of the Corporation. The Audit Committee has the authority to retain, at the Corporation's expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties. The Corporation shall at all times make adequate provisions for the payment of all fees and other compensation approved by the Audit Committee, to the Corporation's independent auditors in connection with the issuance of its audit report, or to any consultants or experts employed by the Audit Committee.

SPECIAL NOTE REGARDING
FORWARD-LOOKING STATEMENTS

Certain statements in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, production volumes, royalties, operating costs, capital expenditures, and other guidance provided throughout this Management's Discussion and Analysis ("MD&A") including the information in the "outlook" section and the sensitivity analysis constitute forward-looking statements. Disclosure of plans relating to existing and future developments, including but not limited to the Horizon Project, Primrose East, Pelican Lake, Gabon Offshore West Africa, and the Kirby Oil Sands Project also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year if necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about Canadian Natural Resources Limited (the "Company") and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are

results, performance or
by such forward-looking
among others: general
which will, among othe
market prices of the Comp
assumptions regarding c
fluctuations in currency
which the Company's cur
conditions in the count
Company conducts business
actions of or against ter
conflict including con
capacity; ability of the
strategy, including explo
impact of competition; t
availability and cost
equipment; ability of th
complete capital prog
subsidiaries' ability to
its products; unexpected
or upgrading the Compan
delays or changes in plan
development projects or
the Company to attract t
build its thermal and oil
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for and production and
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regulations such as restr
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determinable with certa

contained, and are subject to known and unknown risks, uncertainties and other factors that could cause the actual results, performance or achievements of the Company to be materially different from any future

upon other factors, an
would depend upon its ass
all information then avai
refer to the "Risks and
MD&A.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or Management's estimates or opinions change.

SPECIAL NOTE REGARDING
NON-GAAP FINANCIAL MEASURES

Management's Discussion and Analysis includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations and net asset value. These financial measures are not defined by generally accepted accounting principles in Canada ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with Canadian GAAP, in the "Financial Highlights" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis of the financial condition and results of operations of the Company should be read in conjunction with the Company's audited consolidated financial statements and related notes for the year ended December 31, 2008. The consolidated financial statements have been prepared in

oil to estimate relative
may be misleading, part
since the 6 mcf:1 bbl
equivalency at the burne
value equivalency at the
the Company's interest
prices are net of transp
exclude the effect of
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Company's 2008 financial
unless otherwise indicate
the Company's capital pro

Additional information r
its quarterly MD&A for
December 31, 2008 and its
year ended December 31,
www.sedar.com.

This MD&A is dated March

ABBREVIATIONS

ACC ....An
AECO ....Al
lo
API ....Sp
on
sc
ARO ....As
bbl ....ba
bbl/d ....ba
bcf ....bi
boe ....ba
boe/d ....ba
Brent ....Da
C$ ....Ca
CICA ....Ca
Ac
CO2 ....Ca
CO2e ....Ca
Canadian GAAP ....Ge
pr
FPSO ....Fl
Of
GHG ....Gr
GJ ....gi
GJ/d ....gi
Heavy
Differential ....He
WT
Horizon Project .....Ho

accordance with generally accepted accounting principles in Canada ("Canadian GAAP"). A reconciliation of Canadian GAAP to generally accepted accounting principles in the United States ("US GAAP") is included in note 18 to the consolidated financial statements. All dollar amounts are referenced in Canadian dollars, except where otherwise noted. The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude

LIBOR ....Lo
mcf ....th
mmbbl ....mi
mmbtu ....mi
mmcf/d ....mi
NGLs ....Na
NYMEX ....Ne
NYSE ....Ne
PRT ....Pe
SCO ....Sy
SEC ....Un
Ex
TSX ....To
UK ....Un
US ....Un
US GAAP ....Ge
pr
US$ ....Un
WCS ....We
WTI ....We

OBJECTIVE AND STRATEGY

The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value(1) on a per common share basis through the development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves. The Company strives to meet these objectives by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a balanced approach to growth and investments and focuses on creating long-term shareholder value. The Company allocates its capital by maintaining:

- Balance among its products, namely natural gas, light/medium crude oil, Pelican Lake crude oil(2), primary heavy crude oil and thermal heavy crude oil;
- Balance among near-, mid- and long-term projects;
- Balance among acquisitions, exploitation and exploration; and
- Balance between sources and terms of debt financing and maintenance of a strong balance sheet.

(1) discounted value of conventional crude oil and natural gas reserves plus value of undeveloped land, less net debt.

(2) Pelican Lake crude oil is 14-17(0) API oil, which receives medium quality crude netbacks due to lower production costs and lower royalty rates.

The Company's three-phase crude oil marketing strategy includes:

- Blending various crude oil streams with diluents to create more attractive feedstock;
- Supporting and participating in pipeline expansions and/or new additions; and
- Supporting and participating in projects that will increase the downstream conversion capacity for heavy crude oil.

Operational discipline and cost control are fundamental to the Company. By consistently controlling costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Cost control is attained by developing area knowledge, by dominating core areas and by maintaining high working interests and operator status in its properties.

The Company is committed to maintaining a strong balance sheet and flexible capital structure. The Company believes it has built the necessary financial capacity to complete all of its growth projects, including the Horizon Project and its conventional crude oil and natural gas opportunities. Additionally, the Company's risk management hedge program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs.

Strategic accretive acquisitions, like the acquisition of ACC in 2006, are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt financing to selectively acquire properties generating future cash flows in its core regions.

Highlights for the year ended December 31, 2008 include the following:

- Achieved record levels of net earnings, adjusted net earnings from operations, and cash flow from operations;
- Achieved annual crude oil and natural gas production guidance;
- Completed the construction of and achieved first production from the Primrose East Expansion;
- Completed drilling and brought three wells back on production at the Baobab Field, Cote d'Ivoire;
- Development continued on the Olowi Field in offshore Gabon with first oil targeted for Spring 2009;
- Substantially completed construction of Phase 1 of the Horizon Project; and
- Increased dividends per common share.

NET EARNINGS AND CASH FLOW FROM OPERATIONS
Financial Highlights

($ millions, except per common share amounts)		2008		2007		
Revenue, before royalties	$	16,173	$	12,543	$	11
Net earnings	$	4,985	$	2,608	$	2
Per common share - basic and diluted	$	9.22	$	4.84	$	
Adjusted net earnings from operations(1)	$	3,492	$	2,406	$	1
Per common share - basic and diluted	$	6.46	$	4.46	$	
Cash flow from operations (2)	$	6,969	$	6,198	$	4
Per common share - basic and diluted	$	12.89	$	11.49	$	
Dividends declared per common share	$	0.40	$	0.34	$	
Total assets	$	42,650	$	36,114	$	33
Total long-term liabilities	$	20,856	$	19,230	$	19
Capital expenditures, net of dispositions	$	7,451	$	6,425	$	12

(1) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations" presented below lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(2) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from

operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Cash Flow from Operations" presented below lists the effects of certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations

($ millions)	2008	2007	2006
Net earnings as reported	$ 4,985	$ 2,608	$ 2,524
Stock-based compensation (recovery) expense, net of tax(a)	(38)	134	95
Unrealized risk management (gain) loss, net of tax(b)	(2,112)	977	(674
Unrealized foreign exchange loss (gain), net of tax(c)	698	(449)	114
Effect of statutory tax rate and other legislative changes on future income tax liabilities(d)	(41)	(864)	(395
Adjusted net earnings from operations	$ 3,492	$ 2,406	$ 1,664

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of outstanding vested options is recorded as a liability on the Company's balance sheet and periodic changes in the intrinsic value are recognized in net earnings or are capitalized as part of the Horizon Project during the construction period.

(b) Derivative financial instruments are recorded at fair value on the balance sheet, with changes in fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.

(c) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, offset by the impact of cross currency swap hedges, and are recognized in net earnings.

(d) All substantively enacted or enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated balance sheet in determining future income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted or enacted. Income tax rate changes during 2008 resulted in a reduction of future income tax liabilities of approximately $19 million in North America and $22 million in Cote d'Ivoire, Offshore West Africa. Income tax rate and other legislative changes during 2007 resulted in a reduction of future income tax liabilities of approximately $864 million in North America. Income tax rate changes during 2006 resulted in an increase of future income tax liabilities of approximately $110 million in the North Sea, a reduction of approximately $438 million in North America, and a reduction of approximately $67 million in

Cote d'Ivoire, Offshore West Africa.

Cash Flow from Operations

($ millions)	2008	2007	20
Net earnings	$ 4,985	$ 2,608	$ 2,5
Non-cash items:			
Depletion, depreciation and amortization	2,683	2,863	2,3
Asset retirement obligation accretion	71	70	
Stock-based compensation (recovery) expense	(52)	193	1
Unrealized risk management (gain) loss	(3,090)	1,400	(1,0
Unrealized foreign exchange loss (gain)	832	(524)	1
Deferred petroleum revenue tax (recovery) expense	(67)	44	
Future income tax expense (recovery)	1,607	(456)	6
Cash flow from operations	$ 6,969	$ 6,198	$ 4,9

For 2008, the Company reported net earnings of $4,985 million compared to net earnings of $2,608 million for 2007 (2006 - $2,524 million). Net earnings for the year ended December 31, 2008 included net unrealized after-tax income of $1,493 million related to the effects of risk management activities, changes in foreign exchange rates, stock-based compensation, and the impact of statutory tax rate and other legislative changes on future income tax liabilities (2007 - $202 million; 2006 - $860 million). Excluding these items, adjusted net earnings from operations for the year ended December 31, 2008 increased to $3,492 million from $2,406 million for 2007 (2006 - $1,664 million) primarily due to the impact of higher realized pricing, lower depletion, depreciation and amortization expense, and lower interest and administration expense. These factors were partially offset by higher realized risk management losses, higher royalty and production expense, lower sales volumes, and the impact of the stronger Canadian dollar relative to the US dollar during the first half of 2008.

The impacts of unrealized risk management activities, stock-based compensation and changes in foreign exchange rates are expected to continue to contribute to significant volatility in consolidated net earnings and are discussed in detail in the relevant sections of this MD&A.

Cash flow from operations for the year ended December 31, 2008 increased to $6,969 million ($12.89 per common share) from $6,198 million ($11.49 per common share) for 2007 (2006 - $4,932 million; $9.18 per common share). The increase was primarily due to the impact of higher realized pricing and lower interest and administration expense, partially offset by higher realized risk management losses, higher royalty and production expense, higher current income tax expense, lower sales volumes, and the impact of the stronger Canadian dollar relative to the US dollar during the first half of 2008.

For 2008, the Company's average sales price per bbl of crude oil and NGLs increased to $82.41 per bbl from $55.45 per bbl in 2007 (2006 - $53.65 per bbl). The Company's average natural gas price increased to $8.39 per mcf from $6.85 per mcf for 2007 (2006 - $6.72 per mcf).

Total production of crude oil and NGLs before royalties decreased to 315,667 bbl/d from 331,232 bbl/d for 2007 (2006 - 331,998 bbl/d). The decrease in crude oil and NGLs production was primarily due to lower production in the North Sea and Offshore West Africa due to the timing of field turnarounds, the sale of the Company's working interest in the B-Block Fields late in 2007, and the impact of the shut in of a portion of the Baobab Field production, and in North America due to the cyclic nature of the Company's thermal production.

Total natural gas production before royalties decreased to 1,495 mmcf/d from 1,668 mmcf/d for 2007 (2006 - 1,492 mmcf/d). The decrease in natural gas production primarily reflected natural production declines due to the Company's strategic reduction in natural gas drilling activity in North America.

Total crude oil and NGLs and natural gas production volumes before royalties decreased to 564,845 boe/d from 609,206 boe/d for 2007 (2006 - 580,724 boe/d). Total production for 2008 was within the Company's previously issued guidance.

Operating highlights

	2008	2007	2006
Crude oil and NGLs ($/bbl)(1)			
Sales price(2)	$ 82.41	$ 55.45	$ 53.65
Royalties	10.48	5.94	4.48
Production expense	16.26	13.34	12.29
Netback	$ 55.67	$ 36.17	$ 36.88
Natural gas ($/mcf)(1)			
Sales price(2)	$ 8.39	$ 6.85	$ 6.72
Royalties	1.46	1.11	1.29
Production expense	1.02	0.91	0.82
Netback	$ 5.91	$ 4.83	$ 4.61
Barrels of oil equivalent ($/boe)(1)			
Sales price(2)	$ 68.62	$ 49.05	$ 47.92
Royalties	9.78	6.26	5.89
Production expense	11.79	9.75	9.14
Netback	$ 47.05	$ 33.04	$ 32.89

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

($ millions, except per common share amounts)

2008	Total	Dec 31	Sep 30	Jun 30

Revenue, before royalties	$ 16,173	$ 2,511	$ 4,583	$ 5,112	$
Net earnings (loss)	$ 4,985	$ 1,770	$ 2,835	$ (347)	$
Net earnings (loss) per common share					
- basic and diluted	$ 9.22	$ 3.27	$ 5.25	$ (0.65)	$

2007	Total	Dec 31	Sep 30	Jun 30	
Revenue, before royalties	$ 12,543	$ 3,200	$ 3,073	$ 3,152	$
Net earnings	$ 2,608	$ 798	$ 700	$ 841	$
Net earnings per common share					
- basic and diluted	$ 4.84	$ 1.48	$ 1.30	$ 1.56	$

Net earnings (loss) over the eight most recently completed quarters generally reflected fluctuations in realized crude oil and natural gas prices, fluctuations in sales volumes, the impact of mark-to-market accounting of derivative financial instruments and stock-based compensation, fluctuations in depletion, depreciation and amortization charges and foreign exchange rates, and adjustments to future income tax liabilities due to statutory tax rate and other legislative changes. More specifically, volatility in quarterly net earnings was primarily due to:

- Crude oil pricing
  Crude oil prices reflected fluctuating demand, geopolitical uncertainties and fluctuations in the Heavy Differential in North America.

- Natural gas pricing
  Natural gas prices primarily reflected seasonal fluctuations in both the demand for natural gas and inventory storage levels, fluctuations in liquefied natural gas imports into the US, and increased shale gas production in the US.

- Crude oil and NGLs sales volumes
  Crude oil and NGLs sales volumes primarily reflected increased production from the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and development of the Espoir Field. Crude oil and NGLs sales volumes also reflected fluctuations in production from the North Sea and Offshore West Africa due to timing of liftings and maintenance activities and the impact of the shut in of a portion of the Baobab Field production.

- Natural gas sales volumes
  Natural gas sales volumes primarily reflected production declines due to the Company's strategic decision to reduce natural gas drilling activity in North America due to the allocation of capital to higher return crude oil projects, as well as natural decline rates.

- Foreign exchange rates
  Fluctuations in the Canadian dollar relative to the US dollar impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks. Similarly, unrealized foreign exchange gains and losses were recorded with respect to US dollar denominated debt and the re-measurement of North Sea future income

tax liabilities denominated in UK pounds sterling to US dollars, partially offset by the impact of cross currency swap hedges.

- Risk management
  Net earnings (loss) have fluctuated due to the recognition of realized and unrealized gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.

- Changes in income tax expense
  Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

- Stock-based compensation
  Net earnings (loss) have fluctuated due to the mark-to-market movements of the Company's stock-based compensation liability. Stock-based compensation expense (recovery) reflected fluctuations in the Company's share price over the eight most recently completed quarters.

- Production expense
  Production expense has fluctuated company wide primarily due to the impact of the demand for services, industry-wide inflationary cost pressures experienced in prior quarters in all segments, fluctuations in product mix, and the impact of seasonal costs that are dependent on weather.

- Depletion, depreciation and amortization
  Depletion, depreciation and amortization expense has fluctuated due to changes in sales volumes, finding and development costs associated with crude oil and natural gas exploration, and estimated future costs to develop the Company's proved undeveloped reserves.

BUSINESS ENVIRONMENT

(Yearly average)		2008		2007		
WTI benchmark price (US$/bbl)	$	99.65	$	72.40	$	
Dated Brent benchmark price (US$/bbl)	$	96.99	$	72.59	$	
WCS blend differential from WTI (US$/bbl)(1)	$	20.03	$	23.25	$	
WCS blend differential from WTI (%)(1)		20%		32%		
Condensate benchmark price (US$/bbl)	$	100.10	$	72.88	$	
NYMEX benchmark price (US$/mmbtu)	$	8.95	$	6.92	$	
AECO benchmark price (C$/GJ)	$	7.71	$	6.26	$	
US / Canadian dollar average exchange rate	$	0.9381	$	0.9304	$	0
US / Canadian dollar year end exchange rate	$	0.8166	$	1.0120	$	0

(1) Beginning in 2008, the Company has quantified the Heavy Differential using the WCS blend as the heavy crude oil marker. Prior period amounts have been reclassified.

Commodity Prices

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized price is also highly sensitive to fluctuations in foreign exchange rates. The average value of the Canadian dollar in relation to the US dollar fluctuated significantly throughout 2008, with a high of approximately $1.03 in February 2008 and a low of approximately $0.77 in December 2008.

The overall increase in WTI pricing in 2008 reflected strong demand for crude oil and tight supply during the first half of 2008, followed by a significant decrease in demand as a result of worldwide financial and economic events during the fourth quarter of the year. WTI pricing was also impacted by ongoing geopolitical uncertainty resulting in increased market volatility. For 2008, WTI averaged US$99.65 per bbl, an increase of 38% compared to US$72.40 per bbl for 2007 (2006 - US$66.25 per bbl). WTI reached a high of US$147.27 per bbl on July 11, 2008 and a low of US$32.40 per bbl on December 19, 2008.

Brent averaged US$96.99 per bbl for 2008, an increase of 34% compared to US$72.59 per bbl for 2007 (2006 - US$65.18 per bbl). Crude oil sales contracts for the North Sea and Offshore West Africa are typically based on Brent pricing, which was also impacted by worldwide financial and economic events late in the year.

The Company's realized crude oil prices benefited from strong commodity pricing during most of the year and a favorable Heavy Differential. The Heavy Differential averaged 20% of WTI for 2008, compared to 32% for 2007 (2006 - 32%). As the worldwide demand for diesel remained strong and the refinery cracking margins were relatively weak, the Heavy Differential continued to remain strong, despite the falling benchmark pricing late in 2008.

The Company anticipates continued volatility in the crude oil pricing benchmarks due to the unpredictable nature of supply and demand factors, geopolitical events and the global economic slowdown resulting from worldwide financial and economic events. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery cracking margins.

NYMEX natural gas prices averaged US$8.95 per mmbtu for 2008, an increase of 29% from US$6.92 per mmbtu for 2007 (2006 - US$7.26 per mmbtu). The Alberta based AECO natural gas pricing for 2008 increased 23% to average $7.71 per GJ from $6.26 per GJ in 2007 (2006 - $6.62 per GJ). During the first half of 2008, the demand and pricing for natural gas were tracking with oil pricing and general economic activity. During the second half of the year, natural gas pricing decreased due to a significant increase in production from shale gas reservoirs in the US and a significant decline in industrial demand caused by the onset of worldwide financial and economic events.

Operating, Royalty and Capital Costs

Strong commodity prices over the last several years have resulted in increased demand for oilfield services worldwide. This has led to inflationary operating and capital cost pressures throughout the crude oil and natural gas industry, particularly related to drilling activities and oil sands developments.

The crude oil and natural gas industry is also experiencing cost pressures related to environmental regulations, both in North America and internationally. In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in 2010 to address industrial GHG emissions; however future Federal regulatory requirements remain uncertain. The Federal Government has also outlined national and sectoral reduction targets for several categories of air pollutants. In Alberta, GHG regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Two of the Company's facilities, the Primrose/Wolf Lake in-situ heavy crude oil facilities and the Hays sour natural gas plant, fall under the regulations. Commencing July 1, 2008, the British Columbia carbon tax is being assessed at $10/tonne of CO_2e on fuel consumed in the province, increasing to $30/tonne by July 1, 2012. In the UK, GHG regulations have been in effect since 2005. During Phase 1 (2005 - 2007) of the UK National Allocation Plan, the Company operated below its CO_2 allocation. For Phase 2 (2008 - 2012) the Company's CO_2 allocation has been decreased below the Company's estimated current operations emissions. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Continued cost pressures and the final outcome of changes to environmental regulations may adversely impact the Company's future net earnings, cash flow and capital projects. For additional details, refer to the "Greenhouse Gas and Other Air Emissions" section of this MD&A.

The Alberta Government implemented its New Royalty Framework ("NRF") effective January 1, 2009. The NRF includes a number of changes to royalty rates for natural gas, conventional crude oil, and oil sands production. Under the NRF, royalties payable vary according to commodity prices and the productivity of wells. Leading up to the January 2009 implementation of the NRF, the Alberta Government made several adjustments to the originally proposed formula to address unintended consequences. These adjustments affect royalties payable for certain natural gas and crude oil production wells. For additional details, refer to the "Royalties" section of this MD&A.

ANALYSIS OF CHANGES IN REVENUE, BEFORE ROYALTIES AND RISK MANAGEMENT ACTIVITIES

		Changes due to				Changes due to	
($ millions)	2006	Volumes	Prices	Other	2007	Volumes	Prices
North America							
Crude oil and NGLs	$ 5,262	$ 298	$ 287	$ -	$ 5,847	$ (49)	$ 3,013
Natural gas	3,804	452	46	-	4,302	(531)	914
	9,066	750	333	-	10,149	(580)	3,927
North Sea							

Crude oil and NGLs	1,600	(107)	82	-	1,575	(334)	512
Natural gas	16	(2)	8	-	22	(5)	(1)
	1,616	(109)	90	-	1,597	(339)	511
Offshore West Africa							
Crude oil and NGLs	931	(216)	36	-	751	(136)	280
Natural gas	19	5	1	-	25	5	19
	950	(211)	37	-	776	(131)	299
Subtotal							
Crude oil and NGLs	7,793	(25)	405	-	8,173	(519)	3,805
Natural gas	3,839	455	55	-	4,349	(531)	932
	11,632	430	460	-	12,522	(1,050)	4,737
Midstream	72	-	-	2	74	-	-
Intersegment eliminations and other(1)	(61)	-	-	8	(53)	-	-
Total	$ 11,643	$ 430	$ 460	$ 10	$ 12,543	$ (1,050)	$ 4,737

(1) Eliminates primarily internal transportation, electricity charges, and natural gas sales.

Revenue increased 29% to $16,173 million for 2008 from $12,543 million for 2007 (2006 - $11,643 million). The increase was primarily due to increased realized crude oil and NGLs and natural gas prices company-wide.

For 2008, 17% of the Company's crude oil and natural gas revenue was generated outside of North America (2007 - 19%; 2006 - 22%). North Sea accounted for 11% of crude oil and natural gas revenue for 2008 (2007 - 13%; 2006 - 14%), and Offshore West Africa accounted for 6% of crude oil and natural gas revenue for 2008 (2007 - 6%; 2006 - 8%).

ANALYSIS OF PRODUCT PRICES

	2008	2007	2006
Crude oil and NGLs ($/bbl) (1) (2)			
North America	$ 77.42	$ 49.16	$ 46.5
North Sea	$ 100.31	$ 74.99	$ 72.6
Offshore West Africa	$ 97.96	$ 71.68	$ 67.9
Company average	$ 82.41	$ 55.45	$ 53.6
Natural gas ($/mcf) (1) (2)			
North America	$ 8.41	$ 6.87	$ 6.7
North Sea	$ 4.09	$ 4.26	$ 2.6
Offshore West Africa	$ 10.03	$ 5.68	$ 5.3
Company average	$ 8.39	$ 6.85	$ 6.7
Company average ($/boe) (1) (2)	$ 68.62	$ 49.05	$ 47.9

Percentage of gross revenue (2) (excluding midstream revenue)			
Crude oil and NGLs	68%	62%	6
Natural gas	32%	38%	3

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

Realized crude oil and NGLs prices increased 49% to average $82.41 per bbl for 2008 from $55.45 per bbl for 2007 (2006 - $53.65 per bbl). The increase in 2008 was primarily a result of higher WTI and Brent benchmark crude oil prices during most of the year and a narrower Heavy Differential, partially offset by the impact of the stronger Canadian dollar relative to the US dollar during the first half of 2008.

The Company's realized natural gas price increased 22% to average $8.39 per mcf for 2008 from $6.85 per mcf for 2007 (2006 - $6.72 per mcf). The increase in 2008 was primarily a result of increased benchmark prices due to increased industrial demand and lower liquefied natural gas imports into the US in the first half of 2008, partially offset by a significant reduction in industrial demand late in the year as a result of worldwide financial and economic events, and the impact of higher storage levels due to increased shale gas production in the US.

North America

North America realized crude oil prices increased 57% to average $77.42 per bbl for 2008 from $49.16 per bbl for 2007 (2006 - $46.52 per bbl). The increase in 2008 was due to increased WTI benchmark pricing and a narrower Heavy Differential, partially offset by the impact of the strong Canadian dollar during the first half of 2008.

In North America, the Company continues to focus on its crude oil marketing strategy, including the development of a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil conversion capacity. During 2008, the Company contributed approximately 150,000 bbl/d of heavy crude oil blends to the WCS stream. The Company has entered into a 20 year transportation agreement to commit to ship 120,000 bbl/d of heavy sour crude oil on the proposed 500,000 bbl/d Keystone Pipeline US Gulf Coast expansion from Hardisty, Alberta to the US Gulf Coast. Contemporaneously, the Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy sour crude oil to a major US refiner. Deliveries under the agreements are expected to commence in 2012 upon completion of the pipeline expansion and are subject to Keystone's receipt of regulatory approval of the pipeline expansion.

North America realized natural gas prices increased 22% to average $8.41 per mcf for 2008 from $6.87 per mcf for 2007 (2006 - $6.77 per mcf), primarily related to fluctuations in benchmark prices due to the impact of weather and storage levels.

Comparisons of the prices received for the Company's North America production by product type were as follows:

	2008	2007	2006
Wellhead Price (1) (2)			
Light/medium crude oil and NGLs (C$/bbl)	$ 89.04	$ 66.24	$ 63.09
Pelican Lake crude oil (C$/bbl)	$ 76.91	$ 46.29	$ 45.02
Primary heavy crude oil (C$/bbl)	$ 74.91	$ 43.77	$ 41.35
Thermal heavy crude oil (C$/bbl)	$ 71.89	$ 43.49	$ 40.98
Natural gas (C$/mcf)	$ 8.41	$ 6.87	$ 6.77

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

North Sea

North Sea realized crude oil prices increased 34% to average $100.31 per bbl for 2008 from $74.99 per bbl for 2007 (2006 - $72.62 per bbl). Realized crude oil prices per bbl in any particular period are dependant on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. Realized crude oil prices in the North Sea during 2008 benefited from the increased Brent benchmark pricing, partially offset by the impact of the strong Canadian dollar during the first half of 2008.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 37% to average $97.96 per bbl for 2008 from $71.68 per bbl for 2007 (2006 - $67.99 per bbl). Realized crude oil prices per bbl in any particular period are dependant on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. Realized crude oil prices in Offshore West Africa during 2008 benefited from the increased Brent benchmark pricing, partially offset by the impact of the strong Canadian dollar during the first half of 2008.

ANALYSIS OF DAILY PRODUCTION PRODUCTION, BEFORE ROYALTIES

	2008	2007	2006
Crude oil and NGLs (bbl/d)			
North America	243,826	246,779	235,253
North Sea	45,274	55,933	60,056
Offshore West Africa	26,567	28,520	36,689
	315,667	331,232	331,998
Natural gas (mmcf/d)			
North America	1,472	1,643	1,468
North Sea	10	13	15
Offshore West Africa	13	12	9
	1,495	1,668	1,492
Total barrels of oil equivalent (boe/d)	564,845	609,206	580,724
Product mix			

Light/medium crude oil and NGLs	22%	23%	26%
Pelican Lake crude oil	6%	6%	5%
Primary heavy crude oil	16%	15%	16%
Thermal heavy crude oil	12%	11%	11%
Natural gas	44%	45%	42%

Daily Production, Net of Royalties

	2008	2007	2006
Crude oil and NGLs (bbl/d)			
North America	207,933	210,769	205,382
North Sea	45,182	55,825	59,940
Offshore West Africa	22,641	26,012	35,212
	275,756	292,606	300,534
Natural gas (mmcf/d)			
North America	1,225	1,378	1,185
North Sea	10	13	15
Offshore West Africa	11	11	9
	1,246	1,402	1,209
Total barrels of oil equivalent (boe/d)	483,541	526,193	502,024

Daily production and per barrel statistics are presented throughout this MD&A on a "before royalty" or "gross" basis. Production on an "after royalty" or "net" basis is also presented.

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely natural gas, light/medium crude oil and NGLs, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil.

Total production averaged 564,845 boe/d for 2008, a 7% decrease from 609,206 boe/d for 2007 (2006 - 580,724 boe/d).

Total production of crude oil and NGLs before royalties decreased 5% to 315,667 bbl/d for 2008 from 331,232 bbl/d for 2007 (2006 - 331,998 bbl/d). The decrease in crude oil and NGLs production from 2007 primarily reflected lower production in the North Sea and Offshore West Africa due to the timing of field turnarounds and the sale of the Company's working interest in the B-Block Fields late in 2007, and in North America due to the cyclic nature of the Company's thermal production. Crude oil and NGLs production for 2008 was within the Company's previously issued guidance of 313,000 to 318,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 44% of the Company's total production in 2008. Total natural gas production before royalties decreased 10% to 1,495 mmcf/d for 2008 from 1,668 mmcf/d for 2007 (2006 - 1,492 mmcf/d). The decrease in natural gas production from 2007 primarily reflected natural production declines due to the Company's strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects. Natural gas production for 2008 was within the Company's previously issued guidance of 1,492 to 1,506 mmcf/d.

For 2009, revised annual production is forecasted to average between 331,000 and 399,000 bbl/d of crude oil and NGLs and between 1,272 and 1,328 mmcf/d of natural gas.

North America

North America crude oil and NGLs production for 2008 decreased 1% to average 243,826 bbl/d from 246,779 bbl/d for 2007 (2006 - 235,253 bbl/d). The decrease in production from 2007 was primarily due to the cyclic nature of the Company's thermal production.

North America natural gas production for 2008 decreased 10% to average 1,472 mmcf/d from 1,643 mmcf/d for 2007 (2006 - 1,468 mmcf/d). The decrease in natural gas production from 2007 reflected production declines due to the Company's strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects.

North Sea

North Sea crude oil production for 2008 was 45,274 bbl/d, a decrease of 19% from 55,933 bbl/d for 2007 (2006 - 60,056 bbl/d) due to increased planned maintenance, the sale of the Company's working interest in the B-Block Fields late in 2007, expected production declines and delays in development projects.

Offshore West Africa

Offshore West Africa crude oil production for 2008 decreased 7% to 26,567 bbl/d from 28,520 bbl/d for 2007 (2006 - 36,689 bbl/d). Production decreased in 2008 due to expected production declines, partially offset by a full year of production at the recently completed West Espoir development and restoration of certain of the shut-in production at the Baobab Field during the fourth quarter of 2008.

CRUDE OIL INVENTORY VOLUMES

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. The related crude oil volumes by segment, which have not been recognized in revenue, were as follows:

(bbl)	2008	2007
North America, related to pipeline fill	761,351	1,097,526
North Sea, related to timing of liftings	558,904	1,032,723
Offshore West Africa, related to timing of liftings	609,444	8,578
	1,929,699	2,138,827

During 2008, the North America pipeline fill was reduced, increasing cash flow from operations by approximately $18 million.

In addition, during 2008, net production of approximately 127,000 barrels of crude oil produced in the Company's international operations was deferred and included in inventory at December 31, 2008. Notwithstanding the overall increase in inventory, cash flow from operations increased by approximately $5 million, as the increase in cash flow from additional sales volumes in the North Sea more than offset the decrease in cash flow from lower sales volumes in Offshore West Africa due to the timing of liftings.

ROYALTIES

	2008	2007	2006
Crude oil and NGLs ($/bbl) (1)			
North America	$ 11.99	$ 7.19	$ 5.86
North Sea	$ 0.21	$ 0.14	$ 0.13
Offshore West Africa	$ 14.81	$ 6.40	$ 2.81
Company average	$ 10.48	$ 5.94	$ 4.48
Natural gas ($/mcf) (1)			
North America	$ 1.47	$ 1.12	$ 1.31
Offshore West Africa	$ 1.52	$ 0.51	$ 0.22
Company average	$ 1.46	$ 1.11	$ 1.29
Company average ($/boe) (1)	$ 9.78	$ 6.26	$ 5.89
Percentage of revenue (2)			
Crude oil and NGLs	13%	11%	8%
Natural gas	17%	16%	19%
Boe	14%	13%	12%

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

North America

Government royalties on a significant portion of North America crude oil and NGLs production fall under the oil sands royalty regime and are calculated on a project by project basis as a percentage of gross revenue less operating, capital and abandonment costs ("net profit"). For 2008 and prior years, royalties were calculated as 1% of gross revenues until the Company's capital investments in the applicable project were fully recovered, at which time the royalty increased to 25% of net profit. Effective January 1, 2009, changes to the Alberta royalty regime under the NRF include the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout depending on benchmark crude oil pricing.

In addition, effective January 1, 2009, new royalty formulas under the NRF for conventional crude oil and natural gas are to operate on sliding scales ranging up to 50%, determined by commodity prices and well productivity.

Crude oil and NGLs royalties for 2008 continued to reflect strong realized crude oil prices and averaged approximately 15% of gross revenues for 2008 and 2007 (2006 - 13%). North America crude oil and NGLs royalties per bbl are anticipated to average 10% to 15% of gross revenue for 2009.

Natural gas royalties per mcf generally fluctuate with natural gas prices and well productivity. Natural gas royalties averaged approximately 18% of gross revenues for 2008 compared to 16% for 2007 (2006 - 19%), primarily due to increased benchmark natural gas prices. North America natural gas royalties per mcf are anticipated to average 14% to 18% of gross revenue for 2009.

North Sea

North Sea government royalties on crude oil were eliminated effective January 1, 2003. The remaining royalty is a gross overriding royalty on the Ninian Field.

Offshore West Africa

Offshore West Africa production in both Cote d'Ivoire and Gabon is governed by the terms of the various Production Sharing Contracts ("PSCs"). Under the PSCs, revenues are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the Government State Oil Companies. Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been

allocated to the Governments. The Governments' share of profit oil attributable to the Company's equity interest is allocated between royalty expense and current income tax expense in accordance with the PSCs. The Company's capital investments in the Espoir Fields in Cote d'Ivoire were fully recovered in early 2007, increasing royalty rates and current income taxes in accordance with the terms of the PSCs.

Royalty rates as a percentage of revenue averaged approximately 15% for 2008 compared to 9% for 2007 (2006 - 4%). The increase in royalty rates from 2007 was due to the impact of the Company's full recovery of its capital investment in the Espoir Fields in 2007 and the resulting increase in profit oil on which the Government's entitlement is based. The increase was compounded by the impact of the reduction in the Cote d'Ivoire corporate income tax rate enacted early in 2008, which had the effect of increasing the allocation of the Government's share of profit oil to royalties. Offshore West Africa royalty rates are anticipated to average 6% to 10% of gross revenue for 2009, reflecting a lower price environment and the Espoir Field contributing a lower proportion of the total Offshore West Africa production.

PRODUCTION EXPENSE

	2008	2007	2006
Crude oil and NGLs ($/bbl) (1)			
North America	$ 14.96	$ 12.26	$ 11.73
North Sea	$ 26.29	$ 20.78	$ 17.57
Offshore West Africa	$ 10.29	$ 8.32	$ 7.45
Company average	$ 16.26	$ 13.34	$ 12.29
Natural gas ($/mcf) (1)			
North America	$ 1.00	$ 0.90	$ 0.81
North Sea	$ 2.51	$ 2.17	$ 1.40
Offshore West Africa	$ 1.61	$ 1.48	$ 1.19
Company average	$ 1.02	$ 0.91	$ 0.82
Company average ($/boe) (1)	$ 11.79	$ 9.75	$ 9.14

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and NGLs production expense for 2008 increased 22% to $14.96 per bbl from $12.26 per bbl for 2007 (2006 - $11.73 per bbl). The increase in production expense per bbl from 2007 was primarily a result of the higher cost of natural gas for fuel for the Company's thermal operations and increased property tax and power costs. The increase was also a result of the impact of lower production volumes on the fixed cost portion of production costs.

North America natural gas production expense for 2008 increased 11% to $1.00 per mcf from $0.90 per mcf for 2007 (2006 - $0.81 per mcf). The increase in production expense per mcf from 2007 was primarily a result of the Company's strategic reduction in natural gas drilling activity, decreasing natural gas production throughout 2008 and increasing production expense per mcf on the fixed cost portion of production costs.

Production expense per boe for 2009 is anticipated to increase as a result of an overall reduction in budgeted volumes for 2009, while fixed costs, such as property taxes and lease rentals, are forecasted to continue to escalate.

North Sea

North Sea crude oil production expense increased on a per barrel basis from 2007 primarily due to lower production volumes on a relatively fixed operating cost base as well as due to higher planned maintenance costs.

Offshore West Africa

Offshore West Africa crude oil production expense increased on a per barrel basis from 2007 primarily due to lower production volumes on a relatively fixed operating cost base.

MIDSTREAM

($ millions)	2008	2007	2006
Revenue	$ 77	$ 74	$ 72
Production expense	25	22	23
Midstream cash flow	52	52	49
Depreciation	8	8	8
Segment earnings before taxes	$ 44	$ 44	$ 41

The Company's midstream assets consist of three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 80% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The midstream pipeline assets allow the Company to control the transport of its own production volumes as well as earn third party revenue. This transportation control enhances the Company's ability to manage the full range of costs associated with the development and marketing of its heavier crude oil.

DEPLETION, DEPRECIATION AND AMORTIZATION (1)

($ millions, except per boe amounts) (2)	2008	2007	2006
North America (3)	$ 2,226	$ 2,350	$ 1,897
North Sea	317	340	297
Offshore West Africa	132	165	189
Expense	$ 2,675	$ 2,855	$ 2,383

	2008	2007	2006
$/boe	$ 12.97	$ 12.84	$ 11.27

(1) DD&A excludes depreciation on midstream assets.
(2) Amounts expressed on a per unit basis are based on sales volumes.
(3) Amounts include the impact of intersegment eliminations. Depletion, Depreciation and Amortization ("DD&A") expense for 2008 decreased 6% to $2,675 million from $2,855 million for 2007 (2006 - $2,383 million), primarily due to the impact of lower sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION

($ millions, except per boe amounts) (1)	2008	2007	2006
North America	$ 42	$ 38	$ 35
North Sea	27	30	31
Offshore West Africa	2	2	2
Expense	$ 71	$ 70	$ 68
$/boe	$ 0.34	$ 0.32	$ 0.32

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Accretion expense in 2008 was comparable to 2007.

ADMINISTRATION EXPENSE

($ millions, except per boe amounts) (1)	2008	2007	2006
Expense	$ 180	$ 208	$ 180
$/boe	$ 0.87	$ 0.93	$ 0.85

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense for 2008 decreased from 2007 primarily due to decreased staffing costs, including costs related to the Company's share bonus program, as well as due to decreased office lease costs.

STOCK-BASED COMPENSATION

($ millions)	2008	2007	2006
(Recovery) expense	$ (52)	$ 193	$ 139

The Company's Stock Option Plan (the "Option Plan") provides current employees (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The design of the Option Plan balances the need for a long-term compensation program to retain employees with the benefits of reducing the impact of dilution on current Shareholders and the reporting of the obligations associated with stock options. Transparency of the cost of the Option Plan is increased as changes in the intrinsic value of outstanding stock options are recognized each period. The cash payment feature provides option holders with substantially the same benefits and allows them to realize the value of their options through a simplified administration process.

The Company recorded a $52 million ($38 million after-tax) stock-based compensation recovery during 2008 due to a 33% decrease in the Company's share price for the year ended December 31, 2008 (December 31, 2008 - C$48.75; December 31, 2007 - C$72.58; December 31, 2006 - C$62.15; December

31, 2005 - C$57.63), offset by the impact of normal course graded vesting of options granted in prior periods and the impact of vested options exercised or surrendered during the year. As required by Canadian GAAP, the Company records a liability for potential cash payments to settle its outstanding employee stock options each reporting period based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. The liability is revalued at each reporting date to reflect changes in the market price of the Company's common shares and the options exercised or surrendered in the year, with the net change recognized in net earnings, or capitalized during the construction period in the case of the Horizon Project. For the year ended December 31, 2008, the Company recorded a $23 million recovery on previously capitalized stock-based compensation on the Horizon Project (2007 - $58 million capitalized; 2006 - $79 million capitalized).

The stock-based compensation liability reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on December 31, 2008. In periods when substantial stock price changes occur, the Company's earnings are subject to significant volatility. The Company utilizes its stock-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

For the year ended December 31, 2008, the Company paid $207 million for stock options surrendered for cash settlement (2007 - $375 million; 2006 - $264 million).

INTEREST EXPENSE

($ millions, except per boe amounts and interest rates) (1)	2008	2007	2006
Expense, gross	$ 609	$ 632	$ 336
Less: capitalized interest, Horizon Project	481	356	196
Expense, net	$ 128	$ 276	$ 140
$/boe	$ 0.62	$ 1.24	$ 0.66
Average effective interest rate	5.1%	5.5%	5.7%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest expense and the Company's average effective interest rate decreased from 2007 primarily due to a decrease in short term borrowing rates during the last half of 2008 and the impact of the stronger Canadian dollar during the first half of 2008.

On commencement of operations of Phase 1 of the Horizon Project, interest capitalization will cease on this Phase and interest expense will increase accordingly.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, currency and interest rate exposures. The Company's risk management program is not used for speculative purposes.

($ millions)	2008	2007	2006
Crude oil and NGLs financial instruments	$ 2,020	$ 505	$ 1,395
Natural gas financial instruments	(21)	(343)	(70)
Foreign currency contracts	(139)	-	-
Realized loss	$ 1,860	$ 162	$ 1,325
Crude oil and NGLs financial instruments	$(3,104)	$ 1,244	$ (736)
Natural gas financial instruments	16	156	(260)
Foreign currency contracts	(2)	-	(17)
Unrealized (gain) loss	$(3,090)	$ 1,400	$ (1,013)
Net (gain) loss	$(1,230)	$ 1,562	$ 312

The net realized loss (gain) from crude oil and natural gas financial instruments would have decreased (increased) the Company's average realized prices as follows:

	2008	2007	2006
Crude oil and NGLs ($/bbl) (1)	$ 17.45	$ 4.18	$ 11.57
Natural gas ($/mcf) (1)	$ (0.04)	$ (0.56)	$ (0.13)

(1) Amounts expressed on a per unit basis are based on sales volumes.

Complete details related to outstanding derivative financial instruments at December 31, 2008 are disclosed in note 13 to the Company's consolidated financial statements.

The commodity derivative financial instruments currently outstanding have not been designated as hedges for accounting purposes (the "non-designated hedges"). The fair value of these non-designated hedges is based on prevailing forward commodity prices in effect at the end of each reporting period and is reflected in risk management activities in consolidated net earnings. The cash settlement amount of the commodity derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement, as compared to their mark-to-market value at December 31, 2008.

Due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized gain of $3,090 million ($2,112 million after-tax) on its risk management activities for the year ended December 31, 2008 (2007 - $1,400 million unrealized loss, $977 million after-tax; 2006 - $1,013 million unrealized gain, $674 million after-tax).

FOREIGN EXCHANGE

($ millions)	2008	2007	2006
Net realized (gain) loss	$ (114)	$ 53	$ (12)
Net unrealized loss (gain) (1)	832	(524)	134
Net loss (gain)	$ 718	$ (471)	$ 122

(1) Amounts are reported net of the effect of cross currency swap hedges.

The Company's North Sea operations are classified as self-sustaining for the purposes of foreign currency translation. The North Sea operations are initially measured in US dollars and then translated to Canadian dollars using the current rate method, whereby assets and liabilities are translated into Canadian dollars using the exchange rate in effect at the balance sheet date, while revenue and expenses are translated into Canadian dollars using the monthly average exchange rate. Foreign currency gains or losses arising on the translation of non-US dollar monetary assets and liabilities are included in net earnings while subsequent gains or losses arising on translation to Canadian dollars are deferred and included in accumulated other comprehensive income.

During 2008, the Company determined that its operations in Offshore West Africa were now operationally and financially independent and the current rate method of translation was prospectively adopted for translation of the financial statements of the Offshore West African subsidiaries as at December 31, 2008. Prior to this determination, the Company's Offshore West Africa foreign operations were classified as integrated for the purposes of foreign currency translation, and accordingly, Offshore West Africa foreign operations and foreign currency transactions and balances held in North America were directly translated into Canadian dollars using the temporal method. All related foreign exchange gains or losses were included in net earnings.

As a result of foreign currency translation, the Company's operating results are affected by the fluctuations in the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. A majority of the Company's revenue is based on reference to US dollar benchmark prices. An increase in the value of the Canadian dollar in relation to the US dollar results in decreased revenue from the sale of the Company's production. Conversely a decrease in the value of the Canadian dollar in relation to the US dollar results in increased revenue from the sale of the Company's production. Production expenses and future income tax liabilities in the North Sea are subject to foreign currency fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar. The value of the Company's US dollar denominated debt is also impacted by the value of the Canadian dollar in relation to the US dollar.

The net unrealized foreign exchange loss in 2008 was primarily related to the weakening of the Canadian dollar in relation to the US dollar with respect to the US dollar denominated debt, partially offset by the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars. Included in the net unrealized loss for the year ended December 31, 2008 was an unrealized gain of $449 million related to the impact of cross currency swap hedges. The net realized foreign exchange gain for 2008 was primarily due to the result of foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US dollar denominated debt. The Canadian dollar ended the year at US$0.8166 compared to US$1.0120 at December 31, 2007 (December 31, 2006 - US$0.8581).

TAXES

($ millions, except income tax rates)	2008	2007	2006
Current	$ 245	$ 121	$ 219
Deferred	(67)	44	37
Taxes other than income tax	$ 178	$ 165	$ 256

	2008	2007	2006
North America	$ 33	$ 96	$ 143
North Sea	340	210	30
Offshore West Africa	128	74	49
Current income tax	501	380	222
Future income tax	1,607	(456)	652
	2,108	(76)	874
Income tax rate and other legislative change (1) (2) (3)	41	864	395
	$ 2,149	$ 788	$ 1,269
Effective income tax rate before income tax and other legislative changes	30.3%	31.1%	37.3%

(1) Includes the effects of one time recoveries of $19 million due to British Columbia corporate income tax rate reductions and $22 million due to Cote d'Ivoire corporate income tax rate reductions substantively enacted or enacted during 2008.

(2) Includes the effect of one time recoveries of $864 million due to Canadian Federal income tax rate reductions and other legislative changes substantively enacted or enacted during 2007.

(3) Includes the effect of the following:
- o a one time expense of $110 million related to the increased supplementary charge on oil and gas profits in the UK North Sea enacted in 2006.
- o a one time recovery of $438 million due to Canadian Federal, Alberta and Saskatchewan corporate income tax rate reductions enacted in 2006.
- o a one time recovery of $67 million due to Cote d'Ivoire, Offshore West Africa corporate income tax rate reductions enacted in 2006.

Taxes other than income tax primarily includes current and deferred PRT, which is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including related capital and abandonment expenditures.

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. North America current income taxes have been provided on the basis of this corporate structure. In addition, North America and North Sea current income taxes will vary depending on available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

For 2009, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense in Canada of $20 million to $50 million and in the North Sea of $350 million to $450 million.

NET CAPITAL EXPENDITURES (1)

($ millions)	2008	2007	2006
Expenditures on property, plant and equipment			
Net property acquisitions (dispositions) (2)	$ 336	$ (39)	$ 4,733

Land acquisition and retention	86	95	210
Seismic evaluations	107	124	130
Well drilling, completion and equipping	1,664	1,642	2,340
Production and related facilities	1,282	1,205	1,314
Total net reserve replacement expenditures	3,475	3,027	8,727
Horizon Project:			
Phase 1 construction costs	2,732	2,740	2,768
Phase 1 operating and capital inventory	87	-	-
Phase 1 commissioning costs	277	-	-
Phases 2/3 costs	336	124	79
Capitalized interest, stock-based compensation and other	480	437	338
Total Horizon Project (3)	3,912	3,301	3,185
Midstream	9	6	12
Abandonments (4)	38	71	75
Head office	17	20	26
Total net capital expenditures	$ 7,451	$ 6,425	$ 12,025
By segment			
North America	$ 2,344	$ 2,428	$ 7,936
North Sea	319	439	646
Offshore West Africa	811	159	134
Other	1	1	11
Horizon Project	3,912	3,301	3,185
Midstream	9	6	12
Abandonments (4)	38	71	75
Head office	17	20	26
Total	$ 7,451	$ 6,425	$ 12,025

(1) Net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Includes Business Combinations.

(3) Net expenditures for the Horizon Project also include the impact of intersegment eliminations.

(4) Abandonments represent expenditures to settle ARO and have been reflected as capital expenditures in this table.

The Company's operating strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core regions where it can dominate the land base and infrastructure. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for 2008 were $7,451 million compared to $6,425 million for 2007 (2006 - $12,025 million). Excluding the ACC acquisition, net capital expenditures were $7,270 million for 2006. Capital expenditures in 2008 primarily reflected the continued progress on the Company's larger, future growth projects, most notably the Horizon Project, Primrose East, and Gabon, offset by the effects of an overall strategic reduction in the North America natural gas drilling program.

During 2008, the Company drilled a total of 1,121 net wells consisting of 269 natural gas wells, 682 crude oil wells, 131 stratigraphic test and service wells, and 39 wells that were dry. This compared to 1,322 net wells drilled for 2007 (2006 - 1,738 net wells). The Company achieved an overall success rate of 96% for 2008, excluding the stratigraphic test and service wells (2007 - 91%; 2006 - 91%).

North America

North America, excluding the Horizon Project, accounted for approximately 32% of the total capital expenditures for the year ended December 31, 2008 compared to approximately 39% for 2007 (2006 - 67%).

During 2008, the Company targeted 280 net natural gas wells, including 27 wells in Northeast British Columbia, 104 wells in the Northern Plains region, 70 wells in Northwest Alberta, and 79 wells in the Southern Plains region. The Company also targeted 704 net crude oil wells during the year. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 415 primary heavy crude oil wells, 110 Pelican Lake crude oil wells, 74 thermal crude oil wells and 7 light crude oil wells were drilled. Another 98 wells targeting light crude oil were drilled outside the Northern Plains region.

Due to significant differences in relative commodity prices between crude oil and natural gas throughout most of 2008, the Company continued to access its large crude oil drilling inventory to maximize value in both the short and long term. Due to the

Company's focus on drilling crude oil wells in 2007 and 2008 and as a result of royalty changes under the Alberta NRF, natural gas drilling activities have been reduced to manage overall capital spending. Deferred natural gas well locations have been retained in the Company's prospect inventory.

As part of the phased expansion of its In-Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. During 2008, the Company drilled 74 thermal oil wells, 2 water source wells, and 19 stratigraphic test wells and observation wells. Overall Primrose thermal production for 2008 was approximately 65,000 bbl/d (2007 - 64,000 bbl/d; 2006 - 64,000 bbl/d).

The Primrose East Expansion, a new facility located 15 kilometers from the existing Primrose South steam plant and 25 kilometers from the Wolf Lake central processing facility, was completed and first steaming commenced in September 2008, with first production achieved in the fourth quarter of 2008. Subsequent to December 31, 2008, operational issues on one of the pads has caused steaming to cease on all well pads in the Primrose East project area and the Company is working on rectifying the issues.

The next planned phase of the Company's In-Situ Oil Sands assets expansion is the Kirby project located 120 kilometers north of the existing Primrose facilities. During 2007, the Company filed a combined application and Environmental Impact Assessment for this project with Alberta Environment and the Alberta Energy and Utilities Board. Final corporate sanction and project scope will be impacted by environmental regulations and their associated costs. Subject to regulatory approval, crude oil pricing, and capital costs, the Company may proceed with the detailed engineering and design work.

Development of new pads and secondary recovery conversion projects at

Pelican Lake continued as expected throughout 2008. Drilling consisted of 110 horizontal crude oil wells, with plans to drill 58 additional horizontal crude oil wells in 2009. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 37,000 bbl/d in 2008 (2007 - 34,000 bbl/d; 2006 - 30,000 bbl/d).

For 2009, the Company's overall drilling activity in North America is expected to comprise approximately 142 natural gas wells and 465 crude oil wells, excluding stratigraphic and service wells.

Horizon Project

The Company continued the construction, commissioning and staged start up of the Horizon Project, with first production of synthetic crude oil from Phase 1 achieved February 28, 2009, representing a major milestone. Currently, the Company is filling all product tanks in preparation for blending and pipeline shipment.

All major components have been completed and are fully operational, with the exception of the Distillate Hydrotreating Plant (Plant 42). The Naphtha and Gas Oil Hydrotreaters (Plants 41 and 43 respectively) are fully operational and currently capable of producing approximately 55,000 bbl/d. Upon completion of Plant 42, the focus will be on reaching full production capacity of 110,000 bbl/d. Plant 42 has now been turned over to operations for commissioning and is targeted to be operational by the end of April 2009, subject to any unforeseen start up issues.

During the initial stages of the ramp-up of production, the production volumes will fluctuate on a weekly basis until the end of the second quarter of 2009 when the Company expects to see a steady ramp up to full production by the end of 2009. The Company will work towards full capacity throughout 2009 as the plant continues to be fine tuned to design rates with a focus on safety and reliability.

Phase 1 of the Horizon Project was designed, engineered, and constructed in an extremely volatile and inflationary business environment with final construction costs totaling approximately $9.7 billion. Subsequent planned expansion through Phases 2/3, further broken down into a series of four Tranches, are being reprofiled with the goal of attaining better cost management.

North Sea

In 2008, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During 2008, 4.1 net wells were drilled, including 0.9 net water injectors, with an additional 1.2 net wells drilling at year end. Specifically, two production wells were completed at Murchison and one production well was completed at Ninian, with an additional production well in progress at Ninian at year end. The Company also delivered one water injection well at Ninian and further increased volumes injected into the Ninian reservoir.

The Company continued with its planned investment in its long-term facilities and infrastructure strategy and successfully carried out maintenance turnarounds at all five installations during the year. Within the Murchison turnaround the Company successfully implemented a new control system, which has resulted in improved platform uptime.

Offshore West Africa

During 2008, 4.1 net wells were drilled with 0.9 net wells drilling at year end.

Development drilling on West Espoir was completed in early 2008, on budget and on time. At the Baobab Field, the Company delivered three new wells from the drilling program, with a fourth well due to be completed in the second quarter of 2009.

At the 90% owned and operated Olowi Field in offshore Gabon, the Conductor Supported Platform was installed, construction was completed on the FPSO, which arrived on location in February 2009, and construction continued on the wellhead towers and subsea facilities. First crude oil is targeted for late in the first quarter or early in the second quarter of 2009.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	2008	2007	2006
Working capital (deficit) (1)	$ 392	$ (1,382)	$ (832)
Long-term debt (2)(3)	$ 13,016	$ 10,940	$ 11,043
Shareholders' equity			
Share capital	$ 2,768	$ 2,674	$ 2,562
Retained earnings	15,344	10,575	8,141
Accumulated other comprehensive income (loss)	262	72	(13)
Total	$ 18,374	$ 13,321	$ 10,690
Debt to book capitalization (3)(4)	41%	45%	51%
Debt to market capitalization (3)(5)	33%	22%	25%
After tax return on average common shareholders' equity (6)	33%	22%	27%
After tax return on average capital employed (3)(7)	19%	12%	17%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.
(2) Includes the current portion of long-term debt (2008 - $420 million; 2007 and 2006 - $nil).
(3) Long-term debt at December 31, 2008 and 2007 is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs. Amounts for 2006 were not adjusted for these items.
(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.
(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus current and long-term debt.
(6) Calculated as net earnings for the year; as a percentage of average common shareholders' equity for the year.
(7) Calculated as net earnings plus after-tax interest expense for the year; as a percentage of average capital employed. Average capital employed is the average shareholders' equity and current and long-term debt for the year, including $10,678 million in average capital employed related to the Horizon Project (2007 - $7,001 million; 2006 - $3,760 million).

At December 31, 2008, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations is dependent on factors discussed in the "Risks and Uncertainties" section of this MD&A. The Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon these factors, as well as maintaining an investment grade debt rating and the condition of capital and credit markets.

The ongoing worldwide financial and economic events have resulted in a significant tightening of the availability and cost of new sources of liquidity including bank credit facilities and funds derived from debt capital markets. In light of these credit challenges, the Company has undertaken a thorough review of its liquidity sources as well as its exposure to counterparties and has concluded that its capital resources are sufficient to meet ongoing short-, medium- and long-term commitments. Specifically, the Company continues to believe that its internally generated cash flow from operations supported by the implementation of its hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities and its ability to raise new debt on commercially acceptable terms, will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy. Further, the Company believes that its counterparties currently have the financial capacity to settle outstanding obligations in the normal course of business.

On an ongoing basis, the Company continues to focus on the following areas:

- Monitoring cash flow from operations, which is the primary source of funds;

- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages;

- Monitoring credit markets, governments, world banks and the Company's bank syndicates to identify associated risks and exposures;

- Maintaining an active commodity risk management program that manages exposure to crude oil and natural gas price volatility. The Company believes this is an effective tool to manage short- and medium-term changes in spot commodity prices. The Company also monitors its commodity risk management counterparties to ensure they are in position to settle obligations within the contractually agreed terms of settlement;

- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place to minimize the impact in the event of default; and

- Monitoring the Company's 2009 capital and operating plans to provide the required flexibility to deal with commodity price volatility, commitments in respect of capital and operating expenditures, and commitments to retire its non-revolving bank credit facility maturing in October 2009. The Company actively manages the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner. The Company continued the construction, commissioning and staged start up of the Horizon Project, with first production of synthetic crude oil from Phase 1 achieved February 28, 2009.

At December 31, 2008, the Company had $2,082 million of available credit under its bank credit facilities, which together with cash flow from operating activities to be generated in 2009 supported by its commodity risk management program and the ability to actively manage the capital expenditure programs, is forecasted to be sufficient to repay the $2,350 million non-revolving bank credit facility maturing October 2009. Further, the Company's current debt ratings are BBB (high) with a negative trend by DBRS Limited, Baa2 with a stable outlook by Moody's Investors Service and BBB with a stable outlook by Standard & Poor's.

Further details related to the Company's long-term debt at December 31, 2008 are discussed below and in note 5 to the Company's audited annual consolidated financial statements.

At December 31, 2008, the Company's working capital was $392 million, excluding the current portion of long-term debt and including both the current portion of the net mark-to-market asset for risk management derivative financial instruments of $1,851 million and the current portion of the stock-based compensation liability of $159 million, together with related future income tax liabilities of $585 million. The cash settlement amount of the risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement, as compared to their mark-to-market value at December 31, 2008. The settlement of the stock-based compensation liability is dependant upon both the surrender of vested stock options for cash settlement by employees and the value of the Company's share price at the time of surrender.

Long-term debt was $13,016 million at December 31, 2008, resulting in a debt to book capitalization level of 41% as at December 31, 2008 (December 31, 2007 - 45%; December 31, 2006 - 51%). This ratio is near the midpoint of the 35% to 45% range targeted by management, including the impact of capital spending on the Horizon Project. The Company remains committed to maintaining a strong balance sheet and flexible capital structure. The Company has hedged a portion of its crude oil and natural gas production for 2009 and 2010 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs. In the future, the Company may also consider the divestiture of certain non-strategic and non-core properties to gain additional balance sheet flexibility.

The Company's commodity hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This program currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. As at December 31, 2008, in accordance with the policy, approximately 6% of budgeted crude oil volumes were hedged using collars for 2009 and approximately 33% of budgeted natural gas volumes were hedged for the first quarter of 2009. In addition, 92,000 bbl/d of crude oil volumes are protected by put options for 2009 at a strike price of US$100.00 per bbl.

The Company had the following net commodity derivative financial instruments outstanding as at December 31, 2008:

	Remaining term	Volume	Weighted average price
Crude oil			
Crude oil price collars	Jan 2009 - Dec 2009	25,000 bbl/d	US$70.00 - US$111.56
	Apr 2009 - Jun 2009	4,000 bbl/d	US$70.00 - US$90.00
Crude oil puts	Jan 2009 - Dec 2009	92,000 bbl/d	US$100.00
Natural gas			

Natural gas price collars(1)	Jan 2009 - Mar 2009	500,000 GJ/d	C$6.00 - C$8.63

(1) Subsequent to December 31, 2008, the Company entered into 220,000 GJ/d of C$6.00 - C$8.00 natural gas AECO collars for the period January to December 2010.

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

In addition to the financial derivatives noted above, subsequent to December 31, 2008, the Company entered into natural gas physical sales contracts for 400,000 GJ/d at an average fixed price of C$5.29 per GJ at AECO for the period April to December 2009.

LONG-TERM DEBT

The Company's long-term debt of $13,016 million at December 31, 2008 was comprised of drawings under its bank credit facilities and debt issuances under medium and long-term unsecured notes.

Bank Credit Facilities

As at December 31, 2008, the Company had in place unsecured bank credit facilities of $6,232 million, comprised of:

- a $125 million demand credit facility;
- a non-revolving syndicated credit facility of $2,350 million maturing October 2009, as discussed below;
- a revolving syndicated credit facility of $2,230 million maturing June 2012;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a (pound)15 million demand credit facility related to the Company's North Sea operations.

During 2007, one of the revolving syndicated credit facilities was increased from $1,825 million to $2,230 million and a $500 million demand credit facility was terminated. The revolving syndicated credit facilities were also extended and now mature June 2012. Both facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities can be made by way of Canadian dollar and US dollar bankers' acceptances, and LIBOR, US base rate and Canadian prime loans.

In conjunction with the closing of the acquisition of ACC in November 2006, the Company executed a $3,850 million, non-revolving syndicated credit facility maturing October 2009. In March 2007, $1,500 million was repaid, reducing the facility to $2,350 million. During 2009, the Company plans to fully retire this facility from its existing borrowing capacity under its other long-term bank credit facilities, which were $2,050 million at December 31, 2008, supported by cash flow from operating activities, including the commodity risk management activities. In accordance with these plans, and repayments of $420 million made subsequent to December 31, 2008 on this facility, $420 million has been classified as current.

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $372 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2008.

Medium-term notes

The Company has $2,600 million remaining on its outstanding $3,000 million base shelf prospectus filed in September 2007 that allows for the issue of medium-term notes in Canada until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

In December 2007, the Company issued $400 million of unsecured notes maturing December 2010, bearing interest at 5.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

During 2007, $125 million of the 7.40% unsecured debentures due March 1, 2007 were repaid.

Senior Unsecured Notes

The adjustable rate senior unsecured notes bear interest at 6.54%, with the final annual principal repayment of US$31 million due in May 2009. During 2008 and 2007, US$31 million of the senior unsecured notes were repaid each year.

US Dollar Debt Securities

In January 2008, the Company issued US$1,200 million of unsecured notes under a US base shelf prospectus, comprised of US$400 million of 5.15% unsecured notes due February 2013, US$400 million of 5.90% unsecured notes due February 2018, and US$400 million of 6.75% unsecured notes due February 2039. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has US$1,800 million remaining on its outstanding US$3,000 million base shelf prospectus filed in September 2007 that allows for the issue of US dollar debt securities in the United States until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

During 2008, US$8 million of US dollar debt securities were repaid.

In March 2007, the Company issued US$2,200 million of unsecured notes, comprised of US$1,100 million of unsecured notes maturing May 2017 and US$1,100 million of unsecured notes maturing March 2038, bearing interest at 5.70% and 6.25%, respectively. Concurrently, the Company entered into cross currency swaps to fix the Canadian dollar interest and principal repayment amounts on the entire US$1,100 million of unsecured notes due May 2017 at 5.10% and C$1,287 million. The Company also entered into a cross currency swap to fix the Canadian dollar interest and principal repayment amounts on US$550 million of unsecured notes due March 2038 at 5.76% and C$644 million. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

During 2008, the Company terminated the interest rate swaps that had been designated as a fair value hedge of US$350 million of 5.45% unsecured notes due October 2012. Accordingly, the Company ceased revaluing the related debt from the date of termination of the interest rate swaps for subsequent changes in fair value. The fair value adjustment of $20 million at the date of termination is being amortized to interest expense over the remaining term of the debt.

During 2007, the Company de-designated the portion of the US dollar denominated debt previously hedged against its net investment in US dollar based self-sustaining foreign operations. Accordingly, all foreign exchange (gains) losses arising each period on US dollar denominated long-term debt are now recognized in the consolidated statements of earnings.

SHARE CAPITAL

As at December 31, 2008, there were 540,991,000 common shares outstanding and 30,962,000 stock options outstanding. As at March 3, 2009, the Company had 541,149,000 common shares outstanding and 30,285,000 stock options outstanding.

The Company did not renew the Normal Course Issuer Bid during 2008. During 2007 and 2008, the Company did not purchase any common shares for cancellation (2006 - 485,000 common shares were purchased at an average price of $57.33 per common share for a total cost of $28 million).

In March 2009, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.42 per common share for 2009. The increase represents a 5% increase from the prior year. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change. In February 2008, an increase in the annual dividend paid by the Company was approved to $0.40 per common share for 2008. The increase represented an 18% increase from 2007.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. These commitments primarily relate to firm commitments for gathering, processing and transmission services; operating leases relating to offshore FPSOs, drilling rigs and office space; expenditures relating to ARO; as well as long-term debt and interest payments. As at December 31, 2008, no entities were consolidated under CICA Handbook accounting Guideline 15, "consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2008:

($ millions)		2009		2010		2011		2012		2013	
Product transportation and pipeline	$	219	$	184	$	159	$	133	$	124	$
Offshore equipment operating lease	$	175	$	145	$	144	$	116	$	117	$
Offshore drilling	$	251	$	62	$	-	$	-	$	-	$
Asset retirement obligations (1)	$	6	$	7	$	6	$	6	$	6	$
Long-term debt (2)	$	2,385	$	400	$	490	$	429	$	890	$
Interest expense(3)	$	610	$	565	$	543	$	490	$	428	$
Office lease	$	25	$	29	$	23	$	2	$	2	$
Other	$	321	$	180	$	17	$	12	$	8	$

(1) Amounts represent management's estimate of the future undiscounted payments to settle ARO related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2009 - 2013 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(2) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,725 million

of revolving bank credit facilities due to the extendable nature of the facilities.

(3) Interest expense amounts represent the scheduled fixed rate and variable rate cash payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates as of December 31, 2008.

LEGAL PROCEEDINGS

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. In addition, the Company is subject to certain contractor construction claims related to the Horizon Project. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

RESERVES

For the year ended December 31, 2008, the Company retained a qualified independent reserves evaluator, Sproule Associates Limited ("Sproule"), to evaluate 100% of the Company's conventional proved, as well as proved and probable crude oil, NGLs and natural gas reserves(1) and prepare Evaluation Reports on these reserves. The Company has been granted an exemption from certain of the provisions of National Instrument 51-101 - "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute SEC requirements for certain disclosures required under NI 51-101. There are three principal differences between the two standards. The first is the requirement under NI 51-101 to disclose both proved and proved and probable reserves, as well as the related net present value of future net revenues using forecast prices and costs. The second is in the definition of proved reserves; however, as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards that NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material. The third is the requirement to disclose a gross reserve reconciliation (before the consideration of royalties). The Company discloses its conventional crude oil, NGLs and natural gas reserve reconciliations net of royalties in adherence to SEC requirements.

The Company annually discloses proved conventional reserves and the standardized measure of discounted future net cash flows using year end constant prices and costs as mandated by the SEC in the supplementary oil and gas information section of the Company's annual report and in its annual Form 40-F filing with the SEC. The Company has elected to provide the net present value(2) of these same conventional proved reserves as well as its conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. The Company has also elected to provide both proved and proved and probable conventional reserves and the net present value of these reserves using forecast prices and costs as additional voluntary information, which is disclosed in the Company's Annual Information Form.

(1) Conventional crude oil, NGLs and natural gas reserves include all of the Company's light/medium, primary heavy, and thermal crude oil, natural gas, coal bed methane and NGLs reserves. They do not include the Company's oil sands mining reserves.

(2) Net present values of conventional reserves are based upon discounted cash flows prior to the consideration of income taxes and existing asset abandonment liabilities. Future development costs and associated material well abandonment liabilities have been applied.

The following tables summarize the Company's proved conventional crude oil and natural gas reserves, net of royalties, as at December 31, 2008 and 2007:

Crude oil and NGLs (mmbbl)	North America	North Sea	Offshore West Africa	Total
Net conventional proved reserves				
Reserves, December 31, 2007	920	310	128	1,358
Extensions and discoveries	51	-	-	51
Improved recovery	17	6	4	27
Purchases of reserves in place	-	-	-	-
Sales of reserves in place	-	-	-	-
Production	(76)	(17)	(8)	(101)
Economic revisions due to prices	28	(81)	8	(45)
Revisions of prior estimates	8	38	10	56
Reserves, December 31, 2008	948	256	142	1,346

The Company's net proved conventional crude oil reserves at December 31, 2008 totaled 1,346 mmbbl. Approximately 88% of production was replaced by reserve additions during 2008. Extensions and discoveries resulting from exploration and development activities amounted to 51 mmbbl, while net positive revisions amounted to 11 mmbbl.

Natural gas (bcf)	North America	North Sea	Offshore West Africa	Total
Net conventional proved reserves				
Reserves, December 31, 2007	3,521	81	64	3,666
Extensions and discoveries	140	-	-	140
Improved recovery	52	(1)	6	57
Purchases of reserves in place	77	-	-	77
Sales of reserves in place	(1)	-	-	(1)
Production	(449)	(4)	(4)	(457)
Economic revisions due to prices	(19)	(56)	6	(69)
Revisions of prior estimates	202	47	22	271
Reserves, December 31, 2008	3,523	67	94	3,684

The Company's net proved conventional natural gas reserves at December 31, 2008 totaled 3,684 bcf. Approximately 104% of production was replaced by reserve additions during 2008. Extensions and discoveries resulting from exploration and development activities amounted to 140 bcf, while net positive revisions amounted to 202 bcf.

For the year ended December 31, 2008, the Company retained a qualified independent reserves evaluator, GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate Phase 1 to Phase 3 of the Company's Horizon Project and prepare an Evaluation Report on the Company's proved, as well as proved and probable oil sands mining reserves. These reserves were evaluated adhering to the requirements of SEC industry Guide 7 using year end constant pricing and have been disclosed separately from the Company's conventional proved and proved and probable crude oil, NGLs and natural gas reserves.

Synthetic crude oil reserves (1) Net reserves, after royalties (mmbbl)	2008	2007
Proved	1,946	1,761
Proved and probable	2,944	2,680

(1) SCO reserves are based on the upgrading of bitumen using technologies implemented at the Horizon Project.

The net proved SCO reserves increased by 185 mmbbl, while net proved and probable SCO reserves increased by 264 mmbbl. The increases are primarily due to a low constant dollar crude oil price, deferring project payout and thereby reducing royalties paid.

The reserves committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of Sproule and GLJ to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and net present value of remaining conventional crude oil, NGLs and natural gas reserves as well as the Company's quantity of oil sands mining reserves.

RISKS AND UNCERTAINTIES

The Company is exposed to various operational risks inherent in exploring, developing, producing and marketing crude oil and natural gas and the mining and upgrading of bitumen into SCO. These inherent risks include, but are not limited to, the following items:

- Economic risk of finding, producing and replacing reserves at a reasonable cost, including the risk of reserve revisions due to economic and technical factors. Reserve revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Prevailing prices of crude oil and natural gas;
- Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
- Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas;
- Success of exploration and development activities;
- Timing and success of integrating the business and operations of acquired companies;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts;
- Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
- Foreign exchange risk due to fluctuating exchange rates on the Company's US dollar denominated debt and as the majority of sales are based in US dollars;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Risk of catastrophic loss due to fire, explosion or acts of nature;

- Geopolitical risks associated with changing governmental policies, social instability and other political, economic or diplomatic developments in the Company's operations; and
- Other circumstances affecting revenue and expenses.

The Company uses a variety of means to help mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk to an acceptable level. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. Substantially all of the Company's accounts receivables are due within normal trade terms. Derivative financial instruments are utilized to help ensure targets are met and to manage commodity prices, foreign currency rates and interest rate exposure. The Company is exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with substantially all investment grade financial institutions and other entities. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

For additional detail regarding the Company's Risks and Uncertainties, refer to the Company's Annual Information Form.

ENVIRONMENT

The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation, particularly in North America and the North Sea. Existing and expected legislation and regulations will require the Company to address and mitigate the effect of its activities on the environment. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings and cash flow from operations.

The Company's associated risk management strategies focus on working with legislators and regulators to ensure that any new or revised policies, legislation or regulations properly reflect a balanced approach to sustainable development. Specific measures in response to existing or new legislation include a focus on the Company's energy efficiency, air emissions management, released water quality, reduced fresh water use and the minimization of the impact on the landscape. The Company's strategy employs an environmental Management Plan (the "Plan"). Details of the plan and the results are presented to, and reviewed by, the Board of Directors quarterly.

The Company's plan and operating guidelines focus on minimizing the impact of operations while meeting regulatory requirements, regional management frameworks, industry operating standards and guidelines, and internal corporate standards. The Company, as part of this Plan, has implemented a proactive program that includes:

- o An internal environmental compliance audit and inspection program of the Company's operating facilities;
- o A suspended well inspection program to support future development or eventual abandonment;

- o Appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment;
- o An effective surface reclamation program;
- o A due diligence program related to groundwater monitoring;
- o An active program related to preventing and reclaiming spill sites;
- o A solution gas reduction and conservation program;
- o A program to replace the majority of fresh water for steaming with brackish water;
- o Environmental planning for all projects to assess impacts and to implement avoidance and mitigation programs;
- o Reporting for environmental liabilities;
- o A program to optimize efficiencies at the Company's operating facilities; and
- o Continued evaluation of new technologies to reduce environmental impacts.

The Company has also established stringent operating standards in four areas:

- o Implementing cost effective ways of reducing GHG emissions per unit of production;
- o Exercising care with respect to all waste produced through effective waste management plans;
- o Using water-based, environmentally friendly drilling muds whenever possible; and
- o Minimizing produced water volumes onshore and offshore through cost-effective measures.

For 2008, the Company's capital expenditures included $38 million for abandonment expenditures (2007 - $71 million; 2006 - $75 million).

The Company's estimated undiscounted ARO at December 31, 2008 was as follows:

Estimated ARO, undiscounted ($ millions)	2008	2007
North America, including Horizon Project	$ 3,165	$ 3,038
North Sea	1,216	1,286
Offshore West Africa	93	102
	4,474	4,426
North Sea PRT recovery	(529)	(555)
	$ 3,945	$ 3,871

The estimate of ARO is based on estimates of future costs to abandon and restore wells, production facilities and offshore production platforms. Factors that affect costs include number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs in accordance with present legislation and industry operating practice. The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production, lowering costs and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates. The future abandonment costs incurred in the North Sea are estimated to result in a PRT recovery of $529 million (2007 - $555 million; 2006 - $625 million), as abandonment costs are an allowable deduction in determining PRT and may be carried back to reclaim PRT previously paid. The expected PRT recovery reduces the Company's net undiscounted abandonment liability to $3,945 million (2007 - $3,871 million).

GREENHOUSE GAS AND OTHER AIR EMISSIONS

The Company, through the Canadian Association of Petroleum Producers ("CAPP"), is working with legislators and regulators as they develop and implement new GHG emission laws and regulations. Internally, the Company is pursuing an integrated emissions reduction strategy to ensure that it is able to comply with existing and future emissions reduction requirements. The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new policies encourage innovation, energy efficiency, targeted research and development while not impacting competitiveness.

In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in 2010 to address industrial GHG emissions. The Federal Government has also outlined national and sectoral reduction targets for several categories of air pollutants. In Alberta, GHG regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Two of the Company's facilities, the Primrose/Wolf Lake in-situ heavy crude oil facilities and the Hays sour natural gas plant, fall under the regulations. Commencing July 1, 2008, the British Columbia carbon tax is being assessed at $10/tonne of CO_2e on fuel consumed in the province, increasing to $30/tonne by July 1, 2012. In the UK, GHG regulations have been in effect since 2005. During phase 1 (2005 - 2007) of the UK National Allocation Plan, the Company operated below its CO_2 allocation. For phase 2 (2008 - 2012) the Company's CO_2 allocation has been decreased below the Company's estimated current operations emissions. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

There are a number of unresolved issues in relation to Canadian Federal and Provincial GHG regulatory requirements. Key among them is an appropriate facility emission threshold, availability and duration of compliance mechanisms, and resolution of federal/provincial harmonization agreements. The Company continues to pursue GHG emission reduction initiatives including solution

gas conservation, CO_2 capture and sequestration in oil sands tailings, CO_2 capture and storage in association with enhanced oil recovery, and participation in an industry initiative to promote an integrated CO_2 capture and storage network.

The additional requirements of enacted or proposed GHG legislation on the Company's operations will increase capital expenditures and operating expenses, especially those related to the Horizon Project and the Company's other existing and planned large oil sands projects. This may have an adverse effect on the Company's net earnings and cash flow from operations.

Air pollutant standards and guidelines are being developed federally and provincially and the Company is participating in these discussions. Ambient air quality and sector based reductions in air emissions are being reviewed. Through Company and industry participation with stakeholders, guidelines have been developed that adopt a structured process to emission reductions that is commensurate with technological development and operational requirements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make judgements, assumptions and estimates in the application of Canadian GAAP that have a significant impact on the financial results of the Company. Actual results may differ from those estimates, and those differences may be material. Critical accounting estimates are reviewed by the Company's Audit Committee annually. The Company believes the following are the most critical accounting estimates in preparing its consolidated financial statements.

Property, Plant and Equipment / Depletion, Depreciation and Amortization

The Company follows the full cost method of accounting for its conventional crude oil and natural gas properties and equipment. Accordingly, all costs relating to the exploration for and development of conventional crude oil and natural gas reserves, whether successful or not, are capitalized and accumulated in country-by-country cost centres. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of a gain or loss except where such dispositions result in a change in the depletion rate of the specific cost centre of 20% or more. Under Canadian GAAP, substantially all of the capitalized costs and estimated future capital costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country using estimated future prices and costs, rather than single-day, year-end prices and costs ("constant dollar pricing") as required by the SEC for US GAAP purposes.

Under Canadian GAAP, the carrying amount of crude oil and natural gas properties in each cost centre may not exceed their recoverable amount ("the ceiling test"). The recoverable amount is calculated as the undiscounted cash flow using proved reserves and estimated future prices and costs. If the carrying amount of a cost centre exceeds its recoverable amount, an impairment loss equal to the amount by which the carrying amount of the properties exceeds their estimated fair value is charged against net earnings. Fair value is calculated as the cash flow from those properties using proved and probable reserves and estimated future prices and costs, discounted at a risk-free interest rate. No ceiling test impairments were recognized under Canadian GAAP at December 31, 2008, as future net revenues exceeded capitalized costs. Under US GAAP, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are based on constant dollar pricing and are discounted at 10%. Capitalized costs and future net revenues are determined on a net of tax basis. These differences in applying the ceiling test in the current year resulted in the recognition of an after-tax ceiling test impairment of $6,164 million for US GAAP purposes.

The US GAAP ceiling test is based on constant dollar pricing and is highly sensitive to differences in benchmark pricing and the Heavy Differential in effect at year end as opposed to pricing throughout the year. As the Company's crude oil production is weighted towards heavier grades of crude oil, which have historically traded at lower prices at year end due to normal seasonality, constant dollar pricing in effect at year end is generally not representative of average pricing realized throughout the year. Had the US GAAP ceiling test at December 31, 2008 been prepared using average realized pricing throughout 2008, rather than constant dollar pricing, and assuming no other changes in reserves, operating costs, or future development costs, the Company would not have recognized a ceiling test impairment loss in the current year for US GAAP purposes.

The alternate acceptable method of accounting for crude oil and natural gas properties and equipment is the successful efforts method. A major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs would be charged against net earnings in the year incurred rather than being capitalized to property, plant and equipment. In addition, under this method, cost centres are defined based on reserve pools rather than by country. The use of the full cost method usually results in higher capitalized costs and increased DD&A rates compared to the successful efforts method.

Crude Oil and Natural Gas Reserves

The estimation of reserves involves the exercise of judgement. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the timing and amount of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserve estimates would result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates may also result in an impairment of crude oil and natural gas property, plant and equipment carrying amounts under the ceiling test.

Asset Retirement Obligations

Under CICA Handbook Section 3110, "Asset Retirement Obligations", the Company is required to recognize a liability for the future retirement obligations associated with its property, plant and equipment. An ARO is recognized to the extent of a legal obligation associated with the retirement of a tangible long-lived asset the Company is required to settle as a result of an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total ARO amount. These individual assumptions can be subject to change.

The estimated fair values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. Retirement costs equal to the estimated fair value of the ARO are capitalized as part of the cost of associated capital assets and are amortized to expense through depletion over the life of the asset. The fair value of the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's average credit-adjusted risk-free interest rate, which is currently 6.7%. In subsequent periods, the ARO is adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows. The estimates described impact earnings by way of depletion on the retirement cost and accretion on the asset retirement liability. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

An ARO is not recognized for assets with an indeterminate useful life (e.g. Pipeline assets and the Horizon Project upgrader and related infrastructure) because an amount cannot be reasonably determined. An ARO for these assets will be recorded in the first period in which the lives of these assets are determinable.

Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences between the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted or enacted as of the consolidated balance sheet date. Accounting for income taxes is a complex process that requires management to interpret frequently changing laws and regulations (e.g. Changing income tax rates) and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. These interpretations and judgements impact the current and future income tax provisions, future income tax assets and liabilities, and net earnings.

Risk Management Activities

The Company utilizes various derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company has relied primarily on external readily observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction and these differences may be material.

Purchase Price Allocations

The purchase prices of business combinations and asset acquisitions are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future DD&A expense and impairment tests.

The Company has made various assumptions in determining the fair values of the acquired assets and liabilities. The most significant assumptions and judgements relate to the estimation of the fair value of the crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates (a) crude oil and natural gas reserves, and (b) future prices of crude oil and natural gas. Reserve estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgements associated with these estimated reserves are described above in "Crude Oil and Natural Gas Reserves". Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

CONTROL ENVIRONMENT

The Company's management, including the President and Chief Operating Officer and the Chief Financial Officer and Senior Vice-President, Finance, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2008, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized and reported within the time periods specified and such information is accumulated and communicated to the Company's management to allow timely decisions regarding required disclosures.

The Company's management, including the President and Chief Operating Officer and The Chief Financial Officer and Senior Vice-President, Finance also performed an assessment of internal control over financial reporting as at December 31, 2008, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2008 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

While the Company's management, including the President and Chief Operating Officer and the Chief Financial Officer and Senior Vice-President, Finance believes that the Company's disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

NEW ACCOUNTING STANDARDS

Effective January 1, 2008, the Company adopted the following accounting and disclosure standards issued by the CICA:

Capital Disclosures

o Section 1535 - "Capital Disclosures" requires entities to disclose their objectives, policies and processes for managing capital, as well as quantitative data about capital. The standard also requires the disclosure of any externally imposed capital requirements and compliance with those requirements. The standard does not define capital. This standard affects disclosure only and did not impact the Company's accounting for capital.

Inventories

o Section 3031 - "Inventories" replaces Section 3030 - "Inventories" and establishes new standards for the measurement of cost of inventories and expands disclosure requirements for inventories. Adoption of this standard did not have a material impact on the Company's financial statements.

Financial Instruments

- Section 3862 - "Financial Instruments - Disclosure" and Section 3863 "Financial Instruments - presentation" replace Section 3861 - "Financial Instruments - Disclosure and Presentation". Section 3862 enhances disclosure requirements concerning risks and requires quantitative and qualitative disclosures about exposures to risks arising from financial instruments. Section 3863 carries forward the presentation requirements from Section 3861 unchanged. These standards affect disclosures only and did not impact the Company's accounting for financial instruments.

Effective January 1, 2009, the Company will adopt the following new accounting standard issued by the CICA:

Goodwill and Intangible Assets

- Section 3064 - "Goodwill and Intangible Assets" replaces Section 3062 - "Goodwill and Other Intangible Assets" and Section 3450 - "Research and Development Costs." In addition, EIC-27 - "Revenue and Expenditures during the Pre-Operating Period" has been withdrawn. The new standard addresses when an internally generated intangible asset meets the definition of an asset. Adoption of the new standard may impact the Company's future capitalization of certain costs during the development and start-up of large development projects.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board ("IASB") in place of Canadian GAAP effective January 1, 2011.

The Company commenced its IFRS conversion project in 2008 and has established a formal project governance structure. The structure includes a Steering Committee, which consists of senior levels of management from finance and accounting, operations and information technology ("IT"). The Steering Committee provides regular updates to the Company's Senior Management and the Audit Committee of the Board of Directors.

The Company's IFRS conversion project consists of the following phases:

- Phase 1 Diagnostic - identification of potential accounting and reporting differences between Canadian GAAP and IFRS.
- Phase 2 Planning - development of project governance, processes, resources, budget and timeline.
- Phase 3 Policy Delivery and Documentation - establishment of accounting policies under IFRS.
- Phase 4 Policy Implementation - establishment of processes for accounting and reporting, IT change requirements, and education.
- Phase 5 Sustainment - ongoing compliance with IFRS after implementation.

The Company has completed the Diagnostic phase. Significant differences were identified in accounting for Property, Plant & Equipment ("PP&E"), including exploration costs, depletion and depreciation, impairment testing, capitalized interest and asset retirement obligations. Other significant differences were noted in accounting for stock-based compensation, risk management activities, and income taxes. The Company is currently performing the necessary research to develop and document IFRS policies to address the major differences noted. At this time, the impact on the Company's future financial position and results of operations is not reasonably determinable. In addition, IFRS is expected to change prior to adoption in 2011, and the impact of these potential changes is not known. Included in the potential IFRS changes is an exposure draft issued in September 2008 by the IASB that proposes transition rules for oil and gas companies following full cost accounting. The proposed transition rule would allow full cost companies to allocate their existing full cost PP&E balances using reserve values or volumes to IFRS compliant units of account as at the date of conversion without requiring retroactive adjustment. The Company intends to adopt the transition rule if it is approved.

OUTLOOK

The Company continues to implement its strategy of maintaining a large portfolio of varied projects, which the Company believes will enable it, over an extended period of time, to provide consistent growth in production and create shareholder value. Annual budgets are developed, scrutinized throughout the year and revised if necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas. The Company expects production levels in 2009 to average between 331,000 bbl/d and 399,000 bbl/d of crude oil and NGLs and between 1,272 mmcf/d and 1,328 mmcf/d of natural gas.

The forecasted capital expenditures in 2009 are currently expected to be as follows:

($ millions)		2009 Forecast
Conventional crude oil and natural gas		
North America natural gas	$	589
North America crude oil and NGLs		1,138
North Sea		141
Offshore West Africa		553
Property acquisitions, dispositions and midstream		109
	$	2,530
Horizon Project		
Phase 1 - Construction	$	180
Phase 1 - Operating and capital inventory		43
Phase 1 - Commissioning costs		183
Phase 2/3 - Tranche 2		121
Sustaining capital		94
Capitalized interest and other costs		41
	$	662
Total	$	3,192

North America Natural Gas

The 2009 North America natural gas drilling program is highlighted by the continued high-grading of the Company's natural gas asset base as follows:

(Number of wells)	2009 Forecast
Coal bed methane and shallow natural gas	30
Conventional natural gas	66
Cardium natural gas	9
Deep natural gas	37
Total	142

The Company has reduced 2009 natural gas drilling in Alberta due to the anticipated future impact of royalty changes effective January 1, 2009.

North America Crude Oil and NGLs

The 2009 North America crude oil drilling program is highlighted by continued development of the Primrose thermal projects, Pelican Lake, and a strong conventional primary heavy program, as follows:

(Number of wells)	2009 Forecast
Conventional primary heavy crude oil	317
Thermal heavy crude oil	70
Light crude oil	20
Pelican Lake crude oil	58
Total	465

Horizon Project

During the initial stages of the ramp-up of production, the production volumes will fluctuate on a weekly basis until the end of the second quarter of 2009 when the Company expects to see a steady ramp up to full production capacity of 110,000 bbl/d by the end of 2009. The Company will work towards full capacity throughout 2009 as the plant continues to be fine tuned to design rates with a focus on safety and reliability.

North Sea

The 2009 capital forecast for the North Sea includes drilling 0.9 net platform wells with focus on building drilling and workover inventory for 2010.

Offshore West Africa

The 2009 capital forecast for anticipates spending $80 million to complete Phase 2 of the development of the Baobab Field in Cote d'Ivoire. The Company is targeting the fourth well to be completed in the second quarter of 2009.

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2008, excluding mark-to-market gains (losses) on risk management activities and capitalized interest, and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	CASH FLOW FROM OPERATIONS ($millions)	CASH FLOW FROM OPERATIONS (per common share, basic)	N EARNIN ($millio
Price changes			
Crude oil - WTI US$1.00/bbl (1)			
Excluding financial derivatives	$ 112	$ 0.21	$
Including financial derivatives	$ 66	$ 0.12	$
Natural gas - AECO C$0.10/mcf (1)			
Excluding financial derivatives	$ 38	$ 0.07	$
Including financial derivatives	$ 38	$ 0.07	$
Volume changes			
Crude oil - 10,000 bbl/d	$ 87	$ 0.16	$
Natural gas - 10 mmcf/d	$ 18	$ 0.03	$
Foreign currency rate change			
$0.01 change in US$ (1)			
Including financial derivatives	$ 89 - 92	$ 0.17	$ 8 -
Interest rate change - 1%	$ 32	$ 0.06	$

(1) For details of financial instruments in place, refer to note 13 to the Company's audited annual consolidated financial statements as at December 31, 2008.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4
Crude oil and NGLs (bbl/d)				
North America	248,960	245,616	239,973	240,831
North Sea	49,568	45,830	42,760	42,991
Offshore West Africa	28,689	27,631	24,237	25,748
Total	327,217	319,077	306,970	309,570
Natural gas (mmcf/d)				
North America	1,513	1,501	1,467	1,405
North Sea	11	10	9	10
Offshore West Africa	14	15	14	12
Total	1,538	1,526	1,490	1,427

Barrels of oil equivalent (boe/d)					
North America	501,061	495,836	484,542	475,089	
North Sea	51,404	47,545	44,309	44,623	
Offshore West Africa	31,023	30,056	26,505	27,687	
Total	583,488	573,437	555,356	547,399	

PER UNIT RESULTS (1)	Q1	Q2	Q3	Q4	20
Crude oil and NGLs ($/bbl)					
Sales price (2)	$ 78.99	$ 103.73	$ 102.30	$ 45.81	$
Royalties	8.70	14.82	14.17	4.49	
Production expense	14.81	16.39	17.61	16.33	
Netback	$ 55.48	$ 72.52	$ 70.52	$ 24.99	$
Natural gas ($/mcf)					
Sales price (2)	$ 7.77	$ 9.89	$ 8.82	$ 7.03	$
Royalties	1.35	1.86	1.55	1.08	
Production expense	1.03	0.94	1.05	1.06	
Netback	$ 5.39	$ 7.09	$ 6.22	$ 4.89	$
Barrels of oil equivalent ($/boe)					
Sales price (2)	$ 65.09	$ 84.88	$ 80.60	$ 43.84	$
Royalties	8.43	13.26	12.06	5.37	
Production expense	11.02	11.60	12.52	12.05	
Netback	$ 45.64	$ 60.02	$ 56.02	$ 26.42	$

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.

NETBACK ANALYSIS

($/boe) (1)	2008
Sales price (2)	$ 68.62
Royalties	9.78
Production expense (3)	11.79
Netback	47.05
Midstream contribution (3)	(0.25)
Administration	0.87
Interest, net	0.62
Realized risk management loss	8.99
Realized foreign exchange loss (gain)	(0.55)
Taxes other than income tax –	1.18

current	
Current income tax - North America	0.15
Current income tax - North Sea	1.64
Current income tax - Offshore West Africa	0.62
Cash flow	$ 33.78

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.
(3) Excluding inter-segment eliminations.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	
TSX - C$					
Trading Volume (thousands)	134,421	145,018	186,906	213,393	
Share Price ($/share)					
High	$ 76.80	$ 111.30	$ 104.83	$ 72.89	$
Low	$ 58.88	$ 68.08	$ 64.40	$ 34.19	$
Close	$ 70.27	$ 100.84	$ 73.00	$ 48.75	$
Market capitalization as at December 31 ($ millions)					$
Shares outstanding (thousands)					
NYSE - US$					
Trading Volume (thousands)	157,781	190,756	292,659	326,032	
Share Price ($/share)					
High	$ 78.43	$ 109.32	$ 103.40	$ 68.87	$
Low	$ 57.07	$ 66.21	$ 61.82	$ 26.43	$
Close	$ 68.26	$ 100.25	$ 68.46	$ 39.98	$
Market capitalization as at December 31($ millions)					$
Shares outstanding (thousands)					

M A N A G E M E N T ' S R E P O R T

The accompanying consolidated financial statements and all other information contained elsewhere in this Annual Report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies described in the accompanying notes. Where necessary, management has made informed judgements and estimates in accounting for transactions that were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared in accordance with Canadian generally accepted accounting principles appropriate in the circumstances. The financial information presented elsewhere in the Annual Report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized and recorded, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to audit and provide their independent audit opinions on the following:

- the Company's consolidated financial statements as at December 31, 2008; and

- the effectiveness of the Company's internal control over financial reporting as at December 31, 2008.

Their report is presented with the consolidated financial statements.

The Board of Directors (the "Board") is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board exercises this responsibility through the Audit Committee of the Board, which is comprised of non-management directors. The audit committee meets with management and the independent auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board for approval. The consolidated financial statements have been approved by the Board on the recommendation of the Audit Committee.

/s/ Steve W. Laut	/s/ Douglas A. Proll	/s/ Randall S. Davis
Steve W. Laut PRESIDENT & CHIEF OPERATING OFFICER	Douglas A. Proll, CA CHIEF FINANCIAL OFFICER & SENIOR VICE-PRESIDENT, FINANCE	Randall S. Davis, CA VICE-PRESIDENT, FINANCE & ACCOUNTING

March 4, 2009
CALGARY, ALBERTA, CANADA

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as defined in rules 13a-15(f) and 15d-15(f) under the United States Securities exchange act of 1934, as amended.

Management, together with the Company's president and chief operating officer and the Company's chief Financial officer and Senior Vice-president, Finance, performed an assessment of the Company's internal control over financial reporting based on the criteria established in internal control - integrated Framework issued by the committee of Sponsoring organizations of the treadway commission ("COSO").

Based on the assessment, management, together with the Company's president and chief operating officer and the Company's chief Financial officer and Senior Vice-president, Finance, has concluded that the Company's internal control over financial reporting is effective as at December 31, 2008. Management recognizes that all internal control systems have inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Pricewaterhousecoopers LLP, an independent firm of chartered accountants, has provided an opinion on the Company's internal control over financial reporting as at December 31, 2008, as stated in their auditors' report.

/s/ Steve W. Laut	/s/ Douglas A. Proll
Steve W. Laut	Douglas A. Proll, CA
PRESIDENT & CHIEF OPERATING OFFICER	CHIEF FINANCIAL OFFICER &
	SENIOR VICE-PRESIDENT, FINANCE

March 4, 2009
CALGARY, ALBERTA, CANADA

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Canadian Natural Resources Limited

We have completed integrated audits of Canadian Natural Resources Limited's 2008, 2007, and 2006 consolidated financial statements and of its internal control over financial reporting as at December 31, 2008. Our opinions, based on our audits, are presented below.

CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated balance sheets of Canadian Natural Resources Limited (the "Company") as at December 31, 2008 and December 31, 2007, and the related consolidated statements of earnings, shareholders' equity, comprehensive income and cash flows for each of the years in the three year period ended December 31, 2008. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits of the Company's consolidated financial statements in accordance with Canadian generally accepted auditing standards and the standards of the public Company accounting oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and December 31, 2007 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2008 in accordance with Canadian generally accepted accounting principles.

INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited Canadian Natural Resource Limited's internal control over financial reporting as at December 31, 2008, based on criteria established in internal control - integrated Framework issued by the committee of Sponsoring organizations of the treadway commission ("COSO"). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's assessment of internal control over Financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the public Company accounting oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A Company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2008 based on criteria established in internal control - integrated Framework issued by the COSO.

/s/PRICEWATERHOUSECOOPERS LLP

CHARTERED ACCOUNTANTS
CALGARY, ALBERTA, CANADA
March 4, 2009

COMMENTS BY AUDITOR FOR U.S. READERS ON CANADA-U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's consolidated financial statements, such as the changes indicated in the Consolidated Statements of Shareholders' Equity and Comprehensive Income. Our report to the Shareholders dated March 4, 2009 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the consolidated financial statements.

/s/PRICEWATERHOUSECOOPERS LLP

CHARTERED ACCOUNTANTS
CALGARY, ALBERTA, CANADA
March 4, 2009

CONSOLIDATED BALANCE SHEETS

As at December 31 (millions of Canadian dollars)		2008
ASSETS		
Current assets		
Cash and cash equivalents	$	27
Accounts receivable and other		1,514
Future income tax (note 8)		-
Current portion of other long-term assets (note 3)		1,851
		3,392
Property, plant and equipment (note 4)		38,966
Other long-term assets (note 3)		292
	$	42,650
LIABILITIES		
Current liabilities		
Accounts payable	$	383
Accrued liabilities		1,802
Future income tax (note 8)		585
Current portion of long-term debt (note 5)		420
Current portion of other long-term liabilities (note 6)		230
		3,420
Long-term debt (note 5)		12,596
Other long-term liabilities (note 6)		1,124
Future income tax (note 8)		7,136
		24,276
SHAREHOLDERS' EQUITY		
Share capital (note 9)		2,768
Retained earnings		15,344
Accumulated other comprehensive income (note 10)		262
		18,374
	$	42,650

Commitments and contingencies (note 14).

Approved by the Board of Directors:

/s/Catherine M. Best   N. Murray Edwards

Catherine M. Best	N. Murray Edwards
CHAIR OF THE AUDIT COMMITTEE	VICE-CHAIRMAN OF THE BOARD OF
AND DIRECTOR	OF DIRECTORS

CONSOLIDATED STATEMENT OF EARNINGS

For the years ended December 31 (millions of Canadian dollars, except per common share amounts)		2008	
Revenue	$	16,173	$
Less: royalties		(2,017)	
Revenue, net of royalties		14,156	
Expenses			
Production		2,451	
Transportation and blending		1,936	
Depletion, depreciation and amortization		2,683	
Asset retirement obligation accretion (note 6)		71	
Administration		180	
Stock-based compensation (recovery) expense (note 6)		(52)	
Interest, net		128	
Risk management activities (note 13)		(1,230)	
Foreign exchange loss (gain)		718	
		6,885	
Earnings before taxes		7,271	
Taxes other than income tax (note 8)		178	
Current income tax expense (note 8)		501	
Future income tax expense (recovery) (note 8)		1,607	
Net earnings	$	4,985	$
Net earnings per common share (note 12)			
Basic and diluted	$	9.22	$

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

For the years ended December 31 (millions of Canadian dollars)	2008	
Share capital		
Balance - beginning of year	$ 2,674	$
Issued upon exercise of stock options	18	
Previously recognized liability on stock options exercised for common shares	76	
Purchase of common shares under Normal Course Issuer Bid	-	
Balance - end of year	2,768	
Retained earnings		
Balance - beginning of year, as originally reported	10,575	
Transition adjustment on adoption of financial instruments standards	-	
Balance - beginning of year, as restated	10,575	
Net earnings	4,985	
Dividends on common shares (note 9)	(216)	
Purchase of common shares under Normal Course Issuer Bid	-	
Balance - end of year	15,344	
Accumulated other comprehensive income (loss)		
Balance - beginning of year	72	
Transition adjustment on adoption of financial instruments standards	-	
Balance - beginning of year, after effect of transition adjustment	72	
Other comprehensive income (loss), net of taxes	190	
Balance - end of year	262	
Shareholders' equity	$ 18,374	$

C O N S O L I D A T E D   S T A T E M E N T S   O F   C O M P R E H E N S I V E   I N C O M E

For the years ended December 31 (millions of Canadian dollars)	2008	
Net earnings	$ 4,985	$
Net change in derivative financial instruments designated as cash flow hedges		
Unrealized income during the year, net of taxes of $1 million (2007 - $6 million, 2006 - $nil)	30	
Reclassification to net earnings, net of taxes of $6 million (2007 - $45 million, 2006 - $nil)	(12)	
	18	
Foreign currency translation adjustment		
Translation of net investment	172	

Other comprehensive income (loss), net of taxes	190	
Comprehensive income	$ 5,175	$

C O N S O L I D A T E D   S T A T E M E N T S   O F   C A S H   F L O W S

For the years ended December 31 (millions of Canadian dollars)	2008	2007	
Operating activities			
Net earnings	$ 4,985	$ 2,608	$
Non-cash items			
Depletion, depreciation and amortization	2,683	2,863	
Asset retirement obligation accretion	71	70	
Stock-based compensation (recovery) expense	(52)	193	
Unrealized risk management (gain) loss	(3,090)	1,400	
Unrealized foreign exchange loss (gain)	832	(524)	
Deferred petroleum revenue tax (recovery) expense	(67)	44	
Future income tax expense (recovery)	1,607	(456)	
Other	25	38	
Abandonment expenditures	(38)	(71)	
Net change in non-cash working capital (note 15)	(189)	(346)	
	6,767	5,819	
Financing activities			
(Repayment) issue of bank credit facilities, net	(623)	(1,925)	
Issue of medium-term notes	-	273	
Repayment of senior unsecured notes	(31)	(33)	
issue of US dollar debt securities	1,215	2,553	
Issue of common shares on exercise of stock options	18	21	
Dividends on common shares	(208)	(178)	
Purchase of common shares	-	-	
Net change in non-cash working capital (note 15)	46	8	
	417	719	
Investing activities			
Expenditures on property, plant and equipment	(7,433)	(6,464)	
Net proceeds on sale of property, plant and equipment	20	110	
Net expenditures on property, plant and equipment	(7,413)	(6,354)	
Acquisition of Anadarko Canada Corporation (note 16)	-	-	
Net change in non-cash working capital (note 15)	235	(186)	
	(7,178)	(6,540)	
Increase (Decrease) In Cash And Cash Equivalents	6	(2)	

Cash And Cash Equivalents - Beginning Of Year	21	23	
Cash And Cash Equivalents - End Of Year	$ 27	$ 21	$

Supplemental disclosure of cash flow information (note 15)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts in millions of Canadian dollars, unless otherwise stated)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production Company head-quartered in Calgary, Alberta, Canada. The Company's conventional crude oil and natural gas operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Cote d'Ivoire and Gabon in Offshore West Africa.

Within Western Canada, the Company is developing its Horizon oil Sands project (the "Horizon Project") in a series of staged development phases ("phases"). The Horizon Project is designed to produce synthetic crude oil through bitumen mining and upgrading operations.

Also within Western Canada, the Company maintains certain midstream activities that include pipeline operations and an electricity co-generation system.

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP"). A summary of differences between accounting principles in Canada and those generally accepted in the United States ("US GAAP") is contained in note 18.

Significant accounting policies are summarized as follows:

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and partnerships. A significant portion of the Company's activities are conducted jointly with others and the consolidated financial statements reflect only the Company's proportionate interest in such activities.

(B) MEASUREMENT UNCERTAINTY

Management has made estimates and assumptions regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts.

Purchase price allocations; depletion, depreciation and amortization, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. The estimation of reserves involves the exercise of judgement. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that, over time, its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices. As a result, the impact of differences between actual and estimated oil and gas reserves amounts on the consolidated financial statements of future periods may be material.

The calculation of asset retirement obligations includes estimates of the future costs to settle the asset retirement obligation, the timing of the cash flows to settle the obligation, and the future inflation rates. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods may be material.

The calculation of income taxes requires judgement in applying tax laws and regulations, estimating the timing of temporary difference reversals, and estimating the realizability of future tax assets. These estimates impact current and future income tax assets and liabilities, and current and future income tax expense (recovery).

The measurement of petroleum revenue tax expense in the United Kingdom and the related provision in the consolidated financial statements are subject to uncertainty associated with future recoverability of crude oil and natural gas reserves, commodity prices and the timing of future events, which may result in material changes to deferred amounts.

The estimation of fair value for derivative financial instruments requires the use of assumptions. In determining these assumptions, the Company has relied primarily on external, readily observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

(C) CASH AND CASH EQUIVALENTS

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with an original term to maturity at purchase of three months or less are reported as cash equivalents on the balance sheet.

(D) PROPERTY, PLANT AND EQUIPMENT

Conventional Crude Oil And Natural Gas

The Company follows the full cost method of accounting for its conventional crude oil and natural gas properties and equipment as prescribed by Accounting Guideline 16 ("AcG 16") issued by the Canadian Institute of Chartered Accountants ("CICA"). Accordingly, all costs relating to the exploration for and development of conventional crude oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. Directly attributable administrative overhead incurred during the development of certain large capital projects is capitalized until the projects are available for their intended use.

Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of a gain or loss except where such dispositions result in a change in the depletion rate of the specific cost centre of 20% or more.

Oil Sands Mining Operations And Upgrading Operations

The Company's Horizon Project is comprised of both mining operations and upgrading operations and accordingly, capitalized costs related to the Horizon Project are accounted for separately from the Company's Canadian conventional crude oil and natural gas costs. Capitalized mining activity costs include property acquisition, construction and development costs. Construction and development costs are capitalized separately to each phase of the Horizon Project. Construction and development for a particular phase of the Horizon Project is considered complete once the phase is available for its intended use. Costs related to major maintenance turnaround activities will be capitalized and amortized on a straight-line basis over the period to the next scheduled major maintenance turnaround.

Midstream and Other

The Company capitalizes all costs that expand the capacity or extend the useful life of the assets.

(E) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during development of the Horizon Project mine are capitalized to property, plant and equipment. Overburden removal costs incurred during production of the Horizon Project mine will be included in the cost of inventory produced, unless the overburden removal activity has resulted in a betterment of the mineral property, in which case the costs will be capitalized to property, plant and equipment. Capitalized overburden removal costs will be amortized over the life of the mining reserves that directly benefit from the overburden removal activity.

(F) CAPITALIZED INTEREST

The Company capitalizes construction period interest based on the Horizon Project costs incurred and the Company's cost of borrowing. Interest capitalization on a particular phase of the Horizon Project ceases once this phase is available for its intended use.

(G) LEASES

Contractual arrangements that meet the definition of a lease are accounted for as capital leases or operating leases as appropriate. Leases that transfer substantially all of the benefits and risks of ownership to the Company are accounted for as capital leases and are recorded as property, plant and equipment with an offsetting liability. All other leases are accounted for as operating leases whereby lease costs are expensed as incurred.

(H) DEPLETION, DEPRECIATION AND AMORTIZATION

Conventional Crude Oil And Natural Gas

Substantially all costs related to each country-by-country cost centre are depleted on the unit-of-production method based on the estimated proved reserves of that country. Volumes of net production and net reserves before royalties are converted to equivalent units on the basis of estimated relative energy content. In determining its depletion base, the Company includes estimated future costs to be incurred in developing proved reserves and excludes the cost of unproved properties and major development projects. Costs for major development projects, as identified by management, are not subject to depletion until the projects are available for their intended uses. Unproved properties and major development projects are assessed periodically to determine whether impairment has occurred. When proved reserves are assigned or the value of an unproved property or major development project is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion. Processing and production facilities are depreciated on a straight-line basis over their estimated lives.

The Company reviews the carrying amount of its conventional crude oil and natural gas properties ("the properties") relative to their recoverable amount ("the ceiling test") for each cost centre at each annual balance sheet date, or more frequently if circumstances or events indicate impairment may have occurred. The recoverable amount is calculated as the undiscounted cash flow from the properties using proved reserves and expected future prices and costs. If the carrying amount of the properties exceeds their recoverable amount, an impairment loss is recognized in depletion expense equal to the amount by which the carrying amount of the properties exceeds their fair value. Fair value is calculated as the cash flow from those properties using proved and probable reserves and expected future prices and costs, discounted at a risk-free interest rate.

Oil Sands Mining Operations And Upgrading Operations

Upon commencement of operations for the Horizon Project, mine-related costs and costs of the upgrader and related infrastructure located on the Horizon Project site will be amortized on the unit-of-production method based on the estimated proved reserves of the Horizon Project or productive capacity, respectively. Moveable mine-related equipment is depreciated on a straight-line basis over its estimated useful life.

The Company reviews the carrying amount of the Horizon Project relative to its recoverable amount if circumstances or events indicate impairment may have occurred. The recoverable amount is calculated as the undiscounted cash flow from the Horizon Project assets using proved and probable reserves and expected future prices and costs. If the carrying amount exceeds the recoverable amount, an impairment loss is recognized in depletion equal to the amount by which the carrying amount of the assets exceeds fair value. Fair value is calculated as the discounted cash flow from the Horizon Project using proved and probable reserves and expected future prices and costs.

Midstream and Other

Midstream assets are depreciated on a straight-line basis over their estimated lives. The Company reviews the recoverability of the carrying amount of the midstream assets when events or circumstances indicate that the carrying amount might not be recoverable. If the carrying amount of the midstream assets exceeds their recoverable amount, an impairment loss equal to the amount by which the carrying amount of the midstream assets exceeds their fair value is recognized in depreciation.

Other capital assets are amortized on a declining balance basis.

(I) ASSET RETIREMENT OBLIGATIONS

The Company provides for future asset retirement obligations on its resource properties, facilities, production platforms, gathering systems, and oil sands mining operations and tailings ponds based on current legislation and industry operating practices. The fair values of asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred.

Retirement costs equal to the fair value of the asset retirement obligations are capitalized as part of the cost of the associated property, plant and equipment and are amortized to expense through depletion and depreciation over the lives of the respective assets. The fair value of an asset retirement obligation is estimated by discounting the expected future cash flows to settle the asset retirement obligation at the Company's average credit-adjusted risk-free interest rate. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and for changes in the amount or timing of the underlying future cash flows. Actual expenditures are charged against the accumulated asset retirement obligation as incurred.

The Company's Horizon Project upgrader and related infrastructure and its midstream pipelines have an indeterminate life and therefore the fair values of the related asset retirement obligations cannot be reasonably determined. The asset retirement obligations for these assets will be recorded in the year in which the lives of the assets are determinable.

(J) FOREIGN CURRENCY TRANSLATION

Foreign operations that are self-sustaining are translated using the current rate method. Under this method, assets and liabilities are translated to Canadian dollars from their functional currency using the exchange rate in effect at the consolidated balance sheet date. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Gains or losses on translation are included in accumulated other comprehensive income (loss) in shareholders' equity in the consolidated balance sheets.

Foreign operations that are integrated are translated using the temporal method. For foreign currency balances and integrated subsidiaries, monetary assets and liabilities are translated to Canadian dollars at the exchange rate in effect at the consolidated balance sheet date. Non-monetary assets and liabilities are translated at the exchange rate in effect when the assets were acquired or obligations incurred. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Provisions for depletion, depreciation and amortization are translated at the same rate as the related assets. Gains or losses on translation of integrated foreign operations and foreign currency balances are included in the consolidated statements of earnings.

(K) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer, delivery has taken place and collection is reasonably assured. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Revenue as reported represents the Company's share and is presented before royalty payments to governments and other mineral interest owners. Revenue, net of royalties represents the Company's share after royalty payments to governments and other mineral interest owners.

Related costs of goods sold are comprised of production; transportation and blending; and depletion, depreciation and amortization expenses. These amounts have been separately presented in the consolidated statements of earnings.

(L) TRANSPORTATION AND BLENDING

Transportation and blending costs incurred to transport crude oil and natural gas to customers are recorded as a separate cost in the consolidated statements of earnings.

(M) PRODUCTION SHARING CONTRACTS

Production generated from Offshore West Africa is currently shared under the terms of various Production Sharing Contracts ("PSCs"). Revenues are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the respective Government State oil Companies (the "Governments"). Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Governments. The Governments' share of profit oil attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the terms of the PSCs.

(N) PETROLEUM REVENUE TAX

The Company accounts for the UK petroleum revenue tax ("PRT") by the life-of-the-field method. The total future liability or recovery of PRT is estimated using proved and probable reserves and anticipated future sales prices and costs. The estimated future PRT is then apportioned to accounting periods on the basis of total estimated future operating income. Changes in the estimated total future PRT are accounted for prospectively.

(O) INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted or enacted as of the consolidated balance sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in net earnings in the period of the change.

Taxable income arising from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. Accordingly, north america current and future income taxes have been provided on the basis of this corporate structure.

(P) STOCK-BASED COMPENSATION PLANS

The Company accounts for stock-based compensation using the intrinsic value method as the Company's Stock option plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. A liability for potential cash settlements under the option plan is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company's common shares, after consideration of an estimated forfeiture rate. This liability is revalued at each reporting date to reflect changes in the market price of the Company's common shares and actual forfeitures, with the net change recognized in net earnings, or capitalized during the construction period in the case of the Horizon Project. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by employees and any previously recognized liability associated with the stock options are recorded as share capital.

The Company has an employee stock savings plan and a stock bonus plan. Contributions to the employee stock savings plan are recorded as compensation expense at the time of the contribution. Contributions to the stock bonus plan are recognized as compensation expense over the related vesting period.

(Q) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: held-for-trading financial assets and financial liabilities; held-to-maturity investments, loans and receivables; available-for-sale financial assets; and other financial liabilities. All financial instruments are required to be measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Held-for-trading financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. Available-for-sale financial assets are subsequently measured at fair value with changes in fair value recognized in other comprehensive income, net of tax. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash and cash equivalents are classified as held-for-trading and are measured at fair value. Accounts receivable are classified as loans and receivables. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as other financial liabilities. Although the Company does not intend to trade its derivative financial instruments, risk management assets and liabilities are classified as held-for-trading for accounting purposes unless formally designated as hedges.

Transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability and original issue discounts on long-term debt have been included in the carrying value of the related financial asset or liability and are amortized to consolidated net earnings over the life of the financial instrument using the effective interest method.

(R) RISK MANAGEMENT ACTIVITIES

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

Effective January 1, 2007, all derivative financial instruments are recognized on the consolidated balance sheet at estimated fair value at each balance sheet date. The estimated fair value of derivative financial instruments is determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates.

The Company documents all derivative financial instruments that are formally designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company periodically enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts formally designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in consolidated net earnings in the same period or periods in which the crude oil or natural gas is sold. The ineffective portion of changes in the fair value of these designated contracts is immediately recognized in risk management activities in consolidated net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in consolidated net earnings.

The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on certain of its long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are included in interest expense in consolidated net earnings. Changes in the fair value of non-designated interest rate swap contracts are included in risk management activities in consolidated net earnings.

Cross currency swap contracts are periodically used to manage currency exposure on us dollar denominated long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges are included in foreign exchange in consolidated net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially included in other comprehensive income and is reclassified to interest expense when realized, with the ineffective portion recognized in risk management activities in consolidated net earnings. Changes in the fair value of non-designated cross currency swap contracts are included in risk management activities in consolidated net earnings.

Realized gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income on the consolidated balance sheets and amortized into consolidated net earnings in the period in which the underlying hedged item is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized immediately in consolidated net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in consolidated net earnings immediately.

Upon termination of an interest rate swap designated as a fair value hedge, the interest rate swap is de-recognized on the balance sheet and the related long-term debt hedged is no longer revalued for changes in fair value. The fair value adjustment on the long-term debt at the date of termination of the interest rate swap is amortized to interest expense over the remaining term of the debt.

Foreign currency forward contracts are periodically used to manage foreign currency cash management requirements. The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of the foreign currency forward contracts are included in risk management activities in consolidated net earnings.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not clearly and closely related to the host contract.

(S) COMPREHENSIVE INCOME

Comprehensive income is comprised of the Company's net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses on the net investment in self-sustaining foreign operations. Other comprehensive income is shown net of related income taxes.

(T) PER COMMON SHARE AMOUNTS

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. This method assumes that proceeds received from the exercise of in-the-money stock options not accounted for as a liability are used to purchase common shares at the average market price during the year. The Company's option plan described in note 9 results in a liability and expense for all outstanding stock options. As such, the potential common shares associated with the stock options are not included in the calculation of diluted earnings per share. The dilutive effect of other convertible securities is calculated by applying the "if-converted" method, which assumes that the securities are converted at the beginning of the period and that income items are adjusted to net earnings.

(U) RECENTLY ISSUED ACCOUNTING STANDARDS UNDER CANADIAN GAAP

Effective January 1, 2009, the Company will adopt the following new accounting standard issued by the CICA:

Goodwill and Intangible Assets

- o Section 3064 - "Goodwill and Intangible Assets" replaces Section 3062 - "Goodwill and Other Intangible Assets" and Section 3450 - "Research and Development Costs". In addition, EIC-27 - "Revenue and Expenditures During the Pre-operating Period" has been withdrawn. The new standard addresses when an internally generated intangible asset meets the definition of an asset. The adoption of this standard will not have a material impact on the Company's financial statements.

(V) INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the CICA's accounting Standards Board confirmed that Canadian publicly accountable entities will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the international accounting Standards Board in place of Canadian GAAP effective January 1, 2011. The Company is currently assessing which accounting policies will be affected by the change to IFRS and the potential impact of these changes on its financial position and results of operations.

(W) COMPARATIVE FIGURES

Certain prior year figures have been reclassified to conform to the presentation adopted in 2008.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2008, the Company adopted the following new accounting and disclosure standards issued by the CICA:

- Section 1535 - "Capital Disclosures" requires entities to disclose their objectives, policies and processes for managing capital, as well as quantitative data about capital. The standard also requires the disclosure of any externally imposed capital requirements and compliance with those requirements. The standard does not define capital. This standard affected disclosure only and did not impact the Company's accounting for capital (note 11).
- Section 3031 - "Inventories" replaces Section 3030 - "Inventories" and establishes new standards for the measurement of cost of inventories and expands disclosure requirements for inventories. Adoption of this standard did not have a material impact on the Company's financial statements.
- Section 3862 - "Financial Instruments - Disclosure" and Section 3863 - "Financial Instruments - Presentation" replace Section 3861 - "Financial Instruments - Disclosure and Presentation". Section 3862 enhances disclosure requirements concerning risks and requires quantitative and qualitative disclosures about exposures to risks arising from financial instruments. Section 3863 carries forward the presentation requirements from Section 3861 unchanged. These standards affected disclosures only and did not impact the Company's accounting for financial instruments (note 13).

3. OTHER LONG-TERM ASSETS

	2008
Risk management (note 13)	$ 2,119
Other	24
	2,143
Less: current portion	1,851
	$ 292

4. PROPERTY, PLANT AND EQUIPMENT

	2008			2007	
	Cost	Accumulated depletion and depreciation	Net	Cost	Accumulated depletion and depreciation
Conventional crude oil and natural gas					
North America	$ 36,532	$ 14,381	$ 22,151	$ 34,195	$ 12,162
North Sea	4,167	2,119	2,048	3,174	1,446
Offshore West Africa	2,671	777	1,894	1,833	645

Other	40	14	26	39	14
Horizon Project	12,573	-	12,573	8,651	-
Midstream	278	72	206	269	64
Head office	190	122	68	170	98
	$ 56,451	$ 17,485	$ 38,966	$ 48,331	$ 14,429

During the year ended December 31, 2008, the Company capitalized directly attributable administrative costs of $55 million (2007 - $47 million, 2006 - $41 million) in the North Sea and Offshore West Africa, related to exploration and development and$404 million (2007 - $312 million, 2006 - $255 million) in North America, related to the Horizon Project construction.

During the year ended December 31, 2008, the Company capitalized $481 million (2007 - $356 million, 2006 - $196 million) in construction period interest costs related to the Horizon Project.

Included in property, plant and equipment are unproved land and major development projects that are not currently subject to depletion or depreciation:

Conventional crude oil and natural gas
North America
North Sea
Offshore West Africa
Other
Horizon Project

The Company has used the following estimated benchmark future prices ("escalated pricing") in its full cost ceiling tests for conventional crude oil and natural gas activities prepared in accordance with Canadian GAAP, as at December 31, 2008:

	2009	2010	2011	201
Crude oil and NGLs				
North America				
WTI at cushing (US$/bbl)	$ 53.73	$ 63.41	$ 69.53	$ 79.5
Hardisty Heavy 12(degree) API (C$/bbl)	$ 47.05	$ 54.58	$ 59.96	$ 67.5
Edmonton Par (C$/bbl)	$ 65.35	$ 72.78	$ 79.95	$ 86.5

North Sea and Offshore West Africa				
North Sea Brent (US$/bbl)	$ 51.73	$ 61.37	$ 67.45	$ 77.4
Natural gas				
North America				
Henry Hub Louisiana (US$/mmbtu)	$ 6.30	$ 7.32	$ 7.56	$ 8.4
AECO (C$/mmbtu)	$ 6.82	$ 7.56	$ 7.84	$ 8.3
Huntingdon/Sumas (C$/mmbtu)	$ 6.82	$ 7.56	$ 7.84	$ 8.3

5. Long-term debt

Canadian dollar denominated debt
Bank credit facilities
Bankers' acceptances
Medium-term notes
5.50% unsecured debentures due December 17, 2010
4.50% unsecured debentures due January 23, 2013
4.95% unsecured debentures due June 1, 2015

US dollar denominated debt
Senior unsecured notes
Adjustable rate due May 27, 2009 (2008 - US$31 million, 2007 - US$62 million)
US dollar debt securities
7.80% due July 2, 2008 (2008 - US$nil, 2007 - US$8 million)
6.70% due July 15, 2011 (2008 - US$400 million, 2007 - US$400 million)
5.45% due October 1, 2012 (2008 - US$350 million, 2007 - US$350 million)
5.15% due February 1, 2013 (2008 - US$400 million, 2007 - US$nil)
4.90% due December 1, 2014 (2008 - US$350 million, 2007 - US$350 million)
6.00% due August 15, 2016 (2008 - US$250 million, 2007 - US$250 million)
5.70% due May 15, 2017 (2008 - US$1,100 million, 2007 - US$1,100 million)
5.90% due February 1, 2018 (2008 - US$400 million, 2007 - US$nil)
7.20% due January 15, 2032 (2008 - US$400 million, 2007 - US$400 million)
6.45% due June 30, 2033 (2008 - US$350 million, 2007 - US$350 million)
5.85% due February 1, 2035 (2008 - US$350 million, 2007 - US$350 million)
6.50% due February 15, 2037 (2008 - US$450 million, 2007 - US$450 million)
6.25% due March 15, 2038 (2008 - US$1,100 million, 2006 - US$1,100 million)
6.75% due February 1, 2039 (2008 - US$400 million, 2007 - US$nil)
Less - original issue discount on senior unsecured notes and US dollar debt securities (1)

Fair value impact of interest rate swaps on US dollar debt securities (2)

Long-term debt before transaction costs
Less: transaction costs (1) (3)

Less: current portion

(1) The Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying value of the outstanding debt.
(2) The carrying value of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $68 million (2007 - $9 million) to reflect the fair value impact of hedge accounting.
(3) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

Bank Credit Facilities

As at December 31, 2008, the Company had in place unsecured bank credit facilities of $6,232 million, comprised of:

- a $125 million demand credit facility;
- a non-revolving syndicated credit facility of $2,350 million maturing October 2009;
- a revolving syndicated credit facility of $2,230 million maturing June 2012;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a (pound)15 million demand credit facility related to the Company's North Sea operations.

During 2007, one of the revolving syndicated credit facilities was increased from $1,825 million to $2,230 million and a $500 million demand credit facility was terminated. The revolving syndicated credit facilities were also extended and now mature June 2012. Both facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal will be repayable on the maturity date. Borrowings under these facilities can be made by way of Canadian dollar and US dollar bankers' acceptances, and LIBOR, US Base Rate And Canadian Prime Loans.

In Conjunction with the closing of the acquisition of Anadarko Canada Corporation ("ACC") in November 2006 (note 16), the Company executed a $3,850 million, non-revolving syndicated credit facility maturing in October 2009. In March 2007, $1,500 million was repaid, reducing the facility to $2,350 million. During 2009, the Company plans to fully retire this facility from its existing borrowing capacity under its other long-term bank credit facilities, which were $2,050 million at December 31, 2008,

supported by cash flow from operating activities, including the commodity risk management activities. In accordance with these plans, and repayments of $420 million made subsequent to December 31, 2008 on this facility, $420 million has been classified as current.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2008, was 2.2% (2007 - 5.2%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $372 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2008.

Medium-term Notes

The Company has $2,600 million remaining on its outstanding $3,000 million base shelf prospectus filed in September 2007 that allows for the issue of medium-term notes in Canada until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

In December 2007, the Company issued $400 million of unsecured notes maturing December 2010, bearing interest at 5.50%. Proceeds from the Securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

During 2007, $125 million of the 7.40% unsecured debentures due March 1, 2007 were repaid.

Senior Unsecured Notes

The adjustable rate senior unsecured notes bear interest at 6.54%, with the final annual principal repayment of US$31 million due in May 2009. During 2008, US$31 million of the senior unsecured notes were repaid.

US Dollar Debt Securities

In January 2008, the Company issued US$1,200 million of unsecured notes under a US base shelf prospectus, comprised of US$400 million of 5.15% unsecured notes due February 2013, US$400 million of 5.90% unsecured notes due February 2018, and US$400 million of 6.75% unsecured notes due February 2039. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has US$1,800 million remaining on its outstanding US$3,000 million base shelf prospectus filed in September 2007 that allows for the issue of US dollar debt securities in the United States until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

During 2008, US$8 million of US dollar debt securities were repaid.

In March 2007, the Company issued US$2,200 million of unsecured notes, comprised of US$1,100 million of unsecured notes maturing May 2017, and US$1,100 million of unsecured notes maturing March 2038, bearing interest at 5.70% and 6.25%, respectively. Concurrently, the Company entered into cross currency swaps to fix the Canadian dollar interest and principal repayment amounts on the entire US$1,100 million of unsecured notes due May 2017 at 5.10% and C$1,287 million (note 13). The Company also entered into a cross currency swap to fix the Canadian dollar interest and principal repayment amounts on US$550 million of unsecured notes due March 2038 at 5.76% and C$644 million (note 13). Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

During 2008, the Company terminated the interest rate swaps that had been designated as a fair value hedge of US$350 million of 5.45% unsecured notes due October 2012. Accordingly, the Company ceased revaluing the related debt from the date of termination of the interest rate swaps for subsequent changes in fair value. The fair value adjustment of $20 million at the date of termination is being amortized to interest expense over the remaining term of the debt.

During 2007, the Company de-designated the portion of the US dollar denominated debt previously hedged against its net investment in US dollar based self-sustaining foreign operations. Accordingly, all foreign exchange (gains) losses arising each period on US dollar denominated long-term debt are now recognized in the consolidated statements of earnings.

Required Debt Repayments

Required debt repayments are as follows:

Year		Repayment
2009	$	2,385
2010	$	400
2011	$	490
2012	$	429
2013	$	890
Thereafter	$	6,707

No debt repayments are reflected in the above table for $1,725 million of revolving bank credit facilities due to the extendable nature of the facilities. Should the bank credit facilities not be extended by mutual agreement of the Company and the lenders, the entire amounts due under these facilities would be due in 2012.

6. OTHER LONG-TERM LIABILITIES

	2008	2007
Asset retirement obligations	$ 1,064	$ 1,074
Stock-based compensation	171	529
Risk management (note 13)	-	1,474
Other	119	101
	1,354	3,178
Less: current portion	230	1,617
	$ 1,124	$ 1,561

Asset Retirement Obligations

At December 31, 2008, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $4,474 million (2007 - $4,426 million). Payments to settle these asset retirement obligations will occur on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average credit-adjusted risk-free interest rate of 6.7% (2007 - 6.6%; 2006 - 6.7%). A reconciliation of the discounted asset retirement obligations is as follows:

	2008	2007

Balance - beginning of year	$ 1,074	$ 1,166	$ 1
Liabilities incurred	18	21	
Liabilities acquired (note16)	3	-	
Liabilities disposed	-	(65)	
Liabilities settled	(38)	(71)	
Asset retirement obligation accretion	71	70	
Revision of estimates	(156)	35	
Foreign exchange	92	(82)	
Balance - end of year	$ 1,064	$ 1,074	$ 1

Stock-based compensation

The Company recognizes a liability for potential cash settlements under its option plan. The current portion represents the maximum amount of the liability payable within the next twelve month period if all vested options are surrendered for cash settlement.

	2008	2007	
Balance - beginning of year	$ 529	$ 744	$
Stock-based compensation	(52)	193	
Cash payment for options surrendered	(207)	(375)	
Transferred to common shares	(76)	(91)	
Capitalized to Horizon Project	(23)	58	
Balance - end of year	171	529	
Less: current portion	159	390	
	$ 12	$ 139	$

7. EMPLOYEE FUTURE BENEFITS

In connection with the acquisition of ACC, the Company assumed obligations to provide defined contribution pension benefits to certain ACC employees continuing their employment with the Company, and defined benefit pension and other post-retirement benefits to former ACC employees, under registered and unregistered pension plans.

The estimated future cost of providing defined benefit pension and other post-retirement benefits to former ACC employees is actuarially determined using management's best estimates of demographic and financial assumptions. The discount rate of 7.0% (2007 - 5.5%) used to determine accrued benefit obligations is based on a year-end market rate of interest for high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Company contributions to the defined contribution plan are expensed as incurred.

The benefit obligation under the registered pension plan at December 31, 2008 was $27 million (2007 - $32 million). As required by government regulations, the Company has set aside funds with an independent trustee to meet these benefit obligations. As at december 31, 2008, these plan assets had a fair value of $34 million (2007 - $47 million). The unregistered pension plan and other post-retirement benefits are unfunded and have a benefit obligation of $9 million at December 31, 2008 (2007 - $10 million).

8. TAXES

Taxes Other Than Income Tax

	2008	2007	
Current PRT expense	$ 210	$ 97	$
Deferred PRT (recovery) expense	(67)	44	
Provincial capital taxes and surcharges	35	24	
	$ 178	$ 165	$

Income Tax

The provision for income tax is as follows:

	2008	2007	
Current income tax - North America	$ 33	$ 96	$
Current income tax - North Sea	340	210	
Current income tax - Offshore West Africa	128	74	
Current income tax expense	501	380	
Future income tax expense (recovery)	1,607	(456)	
Income tax expense (recovery)	$ 2,108	$ (76)	$

The provision for income tax is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes. The reasons for the difference are as follows:

	2008	2007	
Canadian statutory income tax rate	29.8%	32.5%	
Income tax provision at statutory rate	$ 2,166	$ 877	$ 1
Effect on income taxes of:			
Non-deductible portion of Canadian crown payments	-	-	
Canadian resource allowance	-	-	
Deductible UK petroleum revenue tax	(72)	(71)	

Foreign and domestic tax rate differentials	(5)	(25)	
North America income tax rate and other legislative changes	(19)	(864)	
UK income tax rate changes	-	-	
Cote d'Ivoire income tax rate changes	(22)	-	
Non-taxable portion of foreign exchange loss (gain)	127	(96)	
Stock options exercised in shares	6	63	
Other	(73)	40	
Income tax expense (recovery)	$ 2,108	$ (76)	$

The following table summarizes the temporary differences that give rise to the net future income tax asset and liability:

	2008	
Future income tax liabilities		
Property, plant and equipment	$ 6,303	$
Timing of partnership items	1,276	
Unrealized foreign exchange gain on long-term debt	13	
Unrealized risk management activities	651	
Other	-	
Future income tax assets		
Asset retirement obligations	(372)	
Loss carryforwards for income tax	(62)	
Stock-based compensation	(38)	
Unrealized risk management activities	-	
Other	(7)	
Deferred petroleum revenue tax	(43)	
Net future income tax liability	7,721	
Less: current portion of future income tax liability (asset)	585	
Future income tax liability	$ 7,136	$

During 2008, substantively enacted or enacted income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million in British Columbia and approximately $22 million in Cote d'Ivoire.

During 2007, substantively enacted or enacted income tax rate and other legislative changes resulted in a reduction of future income tax liabilities of approximately $864 million in North America.

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During 2006, enacted income tax rate changes resulted in a reduction of future income tax liabilities of approximately $438 million in North America, an increase of future income tax liabilities of approximately $110 million in the UK North Sea and a reduction of future income tax liabilities of approximately $67 million in Cote d'Ivoire.

During 2003, the Canadian Federal Government enacted legislation to phase in changes to the taxation of resource income by 2007. The legislation reduced the corporate income tax rate on resource income to 21%, the deduction for resource allowance was phased out and a deduction for actual crown royalties paid was phased in. Subsequently, as a result of enacted income tax rate changes in 2007, the Canadian Federal corporate income tax rate is being reduced from 21% in 2007 to 15% in 2012.

9. SHARE CAPITAL

Authorized

200,000 Class 1 preferred shares with a stated value of $10.00 each.

Unlimited number of common shares without par value.

Issued

	2008		2007
Common shares	Number of shares (thousands)	Amount	Number of shares (thousands)
Balance - beginning of year	539,729	$ 2,674	537,903
Issued upon exercise of stock options	1,262	18	1,826
Previously recognized liability on stock options exercised for common shares	-	76	-
Balance - end of year	540,991	$ 2,768	539,729

Normal Course Issuer Bid

The Company did not renew the Normal Course Issuer Bid during 2008. During 2007 and 2008, the Company did not purchase any common shares for cancellation (2006 - 485,000 common shares were purchased at an average price of $57.33 per common share for a total cost of $28 million).

Dividend Policy

The Company has paid regular quarterly dividends in January, April, July and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

In March 2009, the Board of Directors set the Company's regular quarterly dividend at $0.105 per common share (2008 - $0.10 per common share, 2007 - $0.085 per common share).

Stock Options

The Company's Option Plan provides for granting of stock options to employees. Stock options granted under the option plan have terms ranging from five to six years to expiry and vest over a five-year period. The exercise price of each stock option granted is determined at the closing market price of the common shares on the toronto Stock exchange on the day prior to the grant. Each stock option granted provides the holder the choice to purchase one common share of the Company at the stated exercise price or receive a cash payment equal to the difference between the stated exercise price and the market price of the Company's common shares on the date of surrender of the option.

The following table summarizes information relating to stock options outstanding at December 31, 2008 and 2007:

	2008			2007
	Stock options (thousands)		Weighted average exercise price	Stock options (thousands)
Outstanding - beginning of year	30,659	$	47.23	34,431
Granted	7,705	$	53.38	7,502
Surrendered for cash settlement	(3,702)	$	25.60	(7,249)
Exercised for common shares	(1,262)	$	14.61	(1,826)
Forfeited	(2,438)	$	56.56	(2,199)
Outstanding - end of year	30,962	$	51.94	30,659
Exercisable - end of year	8,809	$	44.58	7,640

The range of exercise prices of stock options outstanding and exercisable at December 31, 2008 was as follows:

	Stock options outstanding				Stock opti
Range of exercise prices	Stock options outstanding (thousands)	Weighted average remaining term (years)		Weighted average exercise price	Stoc option exercisabl (thousand
$11.83 - $19.99	2,909	0.51	$	16.44	1,91
$20.00 - $29.99	3,023	1.30	$	25.57	1,45
$30.00 - $39.99	865	1.66	$	33.27	39
$40.00 - $49.99	6,845	5.01	$	46.37	20
$50.00 - $59.99	5,001	2.75	$	58.06	1,86
$60.00 - $69.99	4,884	3.15	$	61.54	1,76
$70.00 - $79.99	6,526	4.20	$	70.76	1,21
$80.00 - $89.99	-	-	$	-	
$90.00 - $92.50	909	5.53	$	92.50	
	30,962	3.32	$	51.94	8,80

10. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of accumulated other comprehensive income, net of taxes, were as follows:

		200
Derivative financial instruments designated as cash flow hedges	$	11
Foreign currency translation adjustment		14
	$	26

During the next twelve months, $19 million is expected to be reclassified to net earnings from accumulated other comprehensive income.

During 2008, the Company determined that its operations in Offshore West Africa were now operationally and financially independent and the current rate method of translation was adopted for translation of the financial statements of the Offshore West African subsidiaries. This change has been applied prospectively. The impact of this change was to increase assets by $32 million, decrease liabilities by $4 million and increase accumulated other comprehensive income by $36 million.

11. CAPITAL DISCLOSURES

As required by Canadian GAAP, effective January 1, 2008, the Company must provide certain disclosures regarding its objectives, policies and processes for managing capital, as well as provide certain quantitative data about capital. As the Company does not have any externally imposed regulatory capital requirements, for the purposes of this disclosure, the Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived non-GAAP financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company aims over time to maintain its debt to book capitalization ratio in the range of 35% to 45%. However, the Company may exceed the high end of such target range if it is investing in capital projects, undertaking acquisitions, or in periods of lower commodity prices. The Company may be below the low end of the target range when cash flow from operating activities is greater than current investment activities. The ratio is currently near the midpoint of the target range at 41% including the impact of capital spending on the Horizon Project.

Readers are cautioned that as the debt to book capitalization ratio has no defined meaning under GAAP, this financial measure may not be comparable to similar measures provided by other reporting entities. Further, there can be no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure at some point in the future.

200

Long-term debt (1)	$	13,01
Total shareholders' equity	$	18,37
Debt to book capitalization		41

(1) Includes the current portion of long-term debt.

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12. NET EARNINGS PER COMMON SHARE

(thousands of shares)		2008
Weighted average common shares outstanding - basic and diluted		540,647
Net earnings - basic and diluted	$	4,985
Net earnings per common share - basic and diluted	$	9.22

13. FINANCIAL INSTRUMENTS

The carrying values of the Company's financial instruments by category are as follows:

Asset (liability)		Loans and receivables at amortized cost
Cash and cash equivalents	$	-
Accounts receivable		1,059
Risk management		-
Accounts payable		-
Accrued liabilities		-
Other long-term liabilities		-
Long-term debt (1)		-
	$	1,059

(1) Includes the current portion of long-term debt.

	Loans and receivables at

Asset (liability)		amortized cost
Cash and cash equivalents	$	-
Accounts receivable		1,143
Accounts payable		-
Accrued liabilities		-
Risk management		-
Other long-term liabilities		-
Long-term debt		-
	$	1,143

The carrying value of the Company's financial instruments approximates their fair value, except for fixed rate long-term debt as noted below:

	2008	
	Carrying value	Fair value
Fixed rate long-term debt (1)	$ 8,943	$ 7,649

(1) The carrying value of US$350 million of 5.45% notes due October 2012, and US$350 million of 4.90% notes due December 2014, have been adjusted by $68 million (2007 - $9 million) to reflect the fair value impact of hedge accounting.

Risk Management

The changes in estimated fair values of derivative financial instruments included in the risk management asset (liability) were recognized in the financial statements as follows:

	2008	
Asset (liability)	Risk management mark-to-market	mark
Balance - beginning of year	$ (1,474)	$
Retained earnings effect of adoption of financial instruments standards	-	
Net cost of outstanding put options	297	
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	3,090	
Interest expense	60	

Foreign exchange		449
Other comprehensive income		18
Settlement of interest rate swaps		(20)
		2,420
Add: put premium financing obligations (1)		(301)
Balance - end of year		2,119
Less: current portion		1,851
	$	268

(1) The Company has negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective options. These obligations have been reflected in the net risk management asset (liability).

Net (gains) losses from risk management activities for the years ended December 31 were as follows:

		2008		2007
Net realized risk management loss	$	1,860	$	162
Net unrealized risk management (gain) loss		(3,090)		1,400
	$	(1,230)	$	1,562

Financial risk Factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk management

The Company uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production. At December 31, 2008, the Company had the following net derivative financial instruments outstanding to manage its commodity price exposures:

	Remaining term	Volume	Weighted average
Crude oil			
Crude oil price collars	Jan 2009 - Dec 2009	25,000 bbl/d	US$70.00 - US$1
	Apr 2009 - Jun 2009	4,000 bbl/d	US$70.00 - US$
Crude oil puts	Jan 2009 - Dec 2009	92,000 bbl/d	US$1

The net cost of outstanding put options of US$242 million will be settled in 2009.

	Remaining term	Volume	Weighted average
Natural gas			
Natural gas price collars (1)	Jan 2009 - Mar 2009	500,000 GJ/d	C$6.00 - C

(1) Subsequent to December 31, 2008, the Company entered into 220,000 GJ/d of C$6.00 - C$8.00 natural gas AECO collars for the period January to December 2010.

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

There were no commodity derivative financial instruments designated as hedges at December 31, 2008.

In addition to the derivative financial instruments noted above, subsequent to December 31, 2008, the Company entered into natural gas physical sales contracts for 400,000 GJ/d at an average fixed price of C$5.29 per GJ at AECO for the period April to December 2009.

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2008, the Company had the following interest rate swap contracts outstanding:

	Remaining term	Amount ($ millions)	Fixed rate	
Interest rate				
Swaps - fixed to floating	Jan 2009 - Dec 2014	US$350	4.90%	LIBO

(1) London Interbank Offered Rate.

All interest rate related derivative financial instruments designated as hedges at December 31, 2008 were classified as fair value hedges.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies in its subsidiaries and in the carrying value of its self-sustaining foreign subsidiaries. The

Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At December 31, 2008, the Company had the following cross currency swap contracts outstanding:

	Remaining Term	Amount ($millions)	Exchange rate (US$/C$)	Interest rate (US$)
Cross currency				
Swaps	Jan 2009 - Aug 2016	US$250	1.116	6.00%
	Jan 2009 - May 2017	US$1,100	1.170	5.70%
	Jan 2009 - Mar 2038	US$550	1.170	6.25%

All cross currency swap derivative financial instruments designated as hedges at December 31, 2008 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, the Company periodically utilizes foreign currency forward contracts to manage certain foreign currency cash management requirements. At December 31, 2008, the Company had US$408 million of these contracts outstanding, with terms of approximately 30 days or less.

Financial instrument sensitivities

As required by Canadian GAAP, effective January 1, 2008, the Company must provide certain quantitative sensitivities related to its financial instruments, which are prepared on a different basis than those sensitivities currently disclosed in the Company's other continuous disclosure documents. The following table summarizes the annualized sensitivities of the Company's net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2008, resulting from changes in the specified variable, with all other variables held constant. These sensitivities are limited to the impact of changes in a specified variable applied to financial instruments only and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally can not be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	Impact on net earnings	Impac com
Commodity price risk		
Increase WTI US$1.00/bbl	$ (32)	$
Decrease WTI US$1.00/bbl	$ 32	$
Increase AECO C$0.10/mcf	$ (1)	$
Decrease AECO C$0.10/mcf	$ 1	$

Interest rate risk			
Increase interest rate 1%	$	(32)	$
Decrease interest rate 1%	$	32	$
Foreign currency exchange rate risk			
Increase exchange rate by US$0.01	$	(35)	$
Decrease exchange rate by US$0.01	$	35	$

b) Credit risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At December 31, 2008, substantially all of the Company's accounts receivables were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At December 31, 2008, the Company had net risk management assets of $2,119 million (December 31, 2007 - $20 million) with specific counterparties related to derivative financial instruments. The Company believes that its counterparties currently have the financial capacity to settle outstanding obligations in the normal course of business.

c) Liquidity Risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, and access to debt capital markets, to meet obligations as they become due. Due to fluctuations in the timing of the receipt and/or disbursement of operating cash flows, the Company believes it has adequate bank credit facilities to provide liquidity.

The maturity dates for financial liabilities are as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years
Accounts payable	$	383	$	-	$	-
Accrued liabilities	$	1,802	$	-	$	-
Other long-term liabilities	$	86	$	18	$	1

Long-term debt (1)	$ 2,385	$ 400	$ 1,809

(1) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,725 million of revolving bank credit facilities due to the extendable nature of the facilities.

14. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2009	2010	2011	2012	2013
Product transportation and pipeline	$ 219	$ 184	$ 159	$ 133	$ 124
Offshore equipment operating leases	$ 175	$ 145	$ 144	$ 116	$ 117
Offshore drilling	$ 251	$ 62	$ -	$ -	$ -
Asset retirement obligations (1)	$ 6	$ 7	$ 6	$ 6	$ 6
Office leases	$ 25	$ 29	$ 23	$ 2	$ 2
Other	$ 321	$ 180	$ 17	$ 12	$ 8

(1) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2009 - 2013 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. In addition, the Company is subject to certain contractor construction claims related to the Horizon Project. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

15. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Changes in non-cash working capital were as follows:

	2008	2007
Decrease (increase) in non-cash working capital		
Accounts receivable and other	$ 111	$ 334
Accounts payable	(4)	(456)

Accrued liabilities		(15)		(402)
Net change in non-cash working capital	$	92	$	(524)
Relating to:				
Operating activities	$	(189)	$	(346)
Financing activities		46		8
Investing activities		235		(186)
	$	92	$	(524)

Other cash flow information:		2008		2007
Interest paid	$	574	$	556
Taxes paid	$	558	$	418

16. BUSINESS COMBINATIONS

Anadarko Canada Corporation

In November 2006, the Company completed the acquisition of all of the issued and outstanding common shares of ACC, a subsidiary of Anadarko Petroleum Corporation, for net cash consideration of $4,641 million including working capital and other adjustments. Substantially all of acc's land and production base are located in Western Canada.

The acquisition was accounted for using the purchase method. Operating results from ACC have been consolidated with the results of the Company effective from November 2, 2006, the date of acquisition, and are reported in the North America segment. The allocation of the net purchase price to assets acquired and liabilities assumed based on their fair values was as follows:

	Novemb
Net purchase price:	
Net cash consideration (1)	$
Net purchase price allocated as follows:	
Non-cash working capital deficit assumed and other	$
Property, plant and equipment	
Long-term debt	
Asset retirement obligation	
Future income tax	
	$

(1) Net cash consideration was reduced by $88 million to reflect the settlement of US dollar forward contracts designated as hedges of the ACC purchase price.

17. SEGMENTED INFORMATION

The Company's conventional crude oil and natural gas activities are conducted in three geographic segments: North America, North Sea and Offshore West Africa. These activities include the exploration, development, production and marketing of conventional crude oil, natural gas liquids and natural gas.

The Company's Horizon Project is a separate segment from conventional crude oil and natural gas activities as the bitumen will be recovered through mining operations. There are currently no revenues for this project and all directly related expenditures have been capitalized.

Midstream activities include the Company's pipeline operations and an electricity co-generation system. Activities that are not included in the above segments are reported in the segmented information as other. Inter-segment eliminations include internal transportation, electricity charges and natural gas sales.

	Conventional Crude Oil and Natural					
	North America			North Sea		
	2008	2007	2006	2008	2007	2006
Segmented revenue	$ 13,496	$ 10,149	$ 9,066	$ 1,769	$ 1,597	$ 1,616
Less: royalties	(1,876)	(1,318)	(1,203)	(4)	(3)	(3)
Revenue, net of royalties	11,620	8,831	7,863	1,765	1,594	1,613
Segmented expenses						
Production	1,881	1,642	1,436	457	432	390
Transportation and blending	1,975	1,595	1,465	10	16	15
Depletion, depreciation and amortization	2,236	2,350	1,897	317	340	297
Asset retirement obligation accretion	42	38	35	27	30	31
Realized risk management activities	1,861	129	1,022	(1)	33	303
Total segmented expenses	7,995	5,754	5,855	810	851	1,036
Segmented earnings before the following	$ 3,625	$ 3,077	$ 2,008	$ 955	$ 743	$ 577

Non-segmented expenses
Administration
Stock-based compensation (recovery) expense
Interest, net

Unrealized risk management activities
Foreign exchange loss (gain)
Total non-segmented expenses
Earnings before taxes
Taxes other than income tax
Current income tax expense
Future income tax expense (recovery)
Net earnings

Capital Expenditures

	2008			
	Net expenditure	Non cash and fair value changes (1)	Capitalized costs	Net expenditure
Conventional crude oil and natural gas				
North America	$ 2,344	$ (7)	$ 2,337	$ 2,428
North Sea	319	(127)	192	439
Offshore West Africa	811	6	817	159
Other	1	-	1	1
	3,475	(128)	3,347	3,027
Horizon Project (2)	3,912	10	3,922	3,301
Midstream	9	-	9	6
Head office	17	-	17	20
	$ 7,413	$ (118)	$ 7,295	$ 6,354

(1) Asset retirement obligations, future income tax adjustments related to differences between carrying value and tax value, and other fair value adjustments.
(2) Net expenditures for the Horizon Project also include capitalized interest, stock-based compensation, and the impact of intersegment eliminations.

	Midstream			Inter-segment elimination and other		
2008	2007	2006	2008	2007	2006	2
$ 77	$ 74	$ 72	$ (113)	$ (53)	$ (61	$ 16,
-	-	-	6	-	-	(2,

77	74	72	(107)	(53)	(61)	14,
25	22	23	(14)	(6)	(6)	2,
-	-	-	(50)	(42)	(38)	1,
8	8	8	(10)	-	-	2,
-	-	-	-	-	-	
-	-	-	-	-	-	1,
33	30	31	(74)	(48)	(44)	9,
$ 44	$ 44	$ 41	$ (33)	$ (5)	$ (17)	5,
						(3,
						(2,
						7,
						1,
						$ 4,

Segmented Assets

	2
Conventional crude oil and natural gas	
North America	$ 24,
North Sea	2,
Offshore West Africa	2,
Other	
Horizon Project	12,
Midstream	
Head office	
	$ 42,

18. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company's consolidated financial statements have been prepared in accordance with Canadian GAAP. These principles conform in all material respects with US GAAP except for those noted below. Certain differences arising from US GAAP disclosure requirements are not addressed.

The application of US GAAP would have the following effects on consolidated net earnings (loss) as reported:

(millions of Canadian dollars, except per common share amounts)	Notes	2008	
Net earnings - Canadian GAAP		$ 4,985	$
Adjustments			
Depletion, net of taxes of $2,503 million (2007 - $1 million, 2006 - $1 million)	(A,D)	(6,169)	
Stock-based compensation, net of taxes of $32 million (2007 - $3 million, 2006 - $18 million)	(B)	(76)	
Future income taxes	(G)	234	
Derivative financial instruments and hedging activities, net of taxes of $nil (2007 - $nil, 2006 - $15 million)	(C,D)	-	
Net earnings (loss) before cumulative effect of change in accounting policy - US GAAP		(1,026)	
Cumulative effect of change in accounting policy, net of taxes of $nil (2007 - $nil, 2006 - $3 million)	(B)	-	
Net earnings (loss) - US GAAP		$ (1,026)	$
Net earnings (loss) before cumulative effect of change in accounting policy - US GAAP per common share			
Basic		$ (1.90)	$
Diluted	(F)	$ (1.90)	$
Net earnings (loss) - US GAAP per common share			
Basic		$ (1.90)	$
Diluted	(F)	$ (1.90)	$

Comprehensive income (loss) under US GAAP would be as follows:

(millions of Canadian dollars)	Notes	2008	
Comprehensive income - Canadian GAAP		$ 5,175	$
US GAAP earnings adjustments		(6,011)	
Derivative financial instruments and hedging activities, net of taxes of $nil (2007 - $nil million; 2006 - $394 million)	(C)	-	
Comprehensive income (loss) - US GAAP		$ (836)	$

The application of US GAAP would have the following effects on the consolidated balance sheets as reported:

		2008	
	Notes	Canadian GAAP	In (De
(millions of Canadian dollars)			
Current assets		$ 3,392	$

Property, plant and equipment	(A,B,D,E)	38,966	
Other long-term assets	(H)	292	
		$ 42,650	$
Current liabilities	(B)	$ 3,420	$
Long-term debt	(H)	12,596	
Other long-term liabilities	(B)	1,124	
Future income tax	(A,B,D,E,G)	7,136	
Share capital		2,768	
Retained earnings		15,344	
Accumulated other comprehensive income		262	
		$ 42,650	$

		2007	
(millions of Canadian dollars)	Notes	Canadian GAAP	Incre (Decre
Current assets		$ 2,181	$
Property, plant and equipment	(A,B,D,E)	33,902	
Other long-term assets	(H)	31	
		$ 36,114	$
Current liabilities	(B)	$ 3,563	$
Long-term debt	(H)	10,940	
Other long-term liabilities	(B)	1,561	
Future income tax	(A,B,D,E,G)	6,729	
Share capital		2,674	
Retained earnings		10,575	(2
Accumulated other comprehensive income		72	
		$ 36,114	$

Notes:

(A) Under Canadian full cost accounting rules, costs capitalized in each country cost centre are limited to an amount equal to the undiscounted, future net revenues from proved reserves using estimated future prices and costs, plus the carrying amount of unproved properties and major development projects (the "ceiling test") as described in note 1(H). Under the full cost method of accounting as set forth by the US Securities and exchange commission, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are based on prices and costs as at the balance sheet date ("constant dollar pricing") and are discounted at 10%. Capitalized costs and future net revenues are determined on a net of tax basis. These differences in applying the ceiling test to current and prior years resulted in the recognition of ceiling test impairments under US GAAP, which reduced property, plant and equipment by $8,697 million in 2008 (2007 - $36 million, 2006 - $40 million).

For the year ended December 31, 2008, US GAAP net earnings would have decreased by $6,164 million, net of income taxes of $2,501 million to reflect the impact of a current year ceiling test impairment. In addition, the impact of prior ceiling test impairments would have increased US GAAP net earnings by $3 million (2007 - decreased by $4 million, 2006 - increased by $3 million), net of income taxes of $1 million (2007 - $8 million, 2006 - $2 million) to reflect the impact of lower depletion charges. The 2007 income tax effect includes the effect of enacted Canadian income tax rate changes on this item.

(B) The Company accounts for its stock-based compensation liability under Canadian GAAP using the intrinsic value method, as described in note 1(P). Under US GAAP, effective January 1, 2006, the Company would have adopted Financial Accounting Standards Board Statement ("FAS") 123(R), which requires companies to account for all stock-based compensation liabilities using the fair value method, where fair value is measured using an option pricing model. The Company uses the Black Scholes option pricing model to determine the fair value of its stock-based compensation liability for US GAAP purposes. The previous US GAAP standard, FAS 123, required companies to account for cash settled stock-based compensation liabilities using the intrinsic value method. For the year ended December 31, 2008, US GAAP net earnings would have decreased by $76 million (2007 - $22 million, 2006 - $48 million), net of income taxes of $32 million (2007 - $3 million, 2006 - $21 million including the cumulative effect of the change in accounting policy of $8 million, net of income taxes of $3 million). The 2007 income tax effect includes the effect of enacted Canadian income tax rate changes on this item.

(C) Effective January 1, 2007, the Company adopted new accounting standards for financial instruments. The Company's accounting policies for financial instruments under Canadian GAAP are described in notes 1(Q) and 1(R). After adopting the new standards, Canadian GAAP is substantially harmonized with US GAAP as prescribed by FAS 133, "Accounting for Derivative Financial Instruments and Hedging Activities," as amended by FAS 138 and FAS 149.

Prior to adoption of the new accounting policies, the net earnings associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the year ended December 31, 2006 would have been $29 million, net of income taxes of $15 million. Comprehensive income would have increased by $805 million as a result of recording all derivative financial instruments at fair value in accordance with US GAAP.

(D) During 2006, under Canadian GAAP, the Company hedged the foreign currency component of the US dollar purchase price of ACC using derivative financial instruments formally designated as cash flow hedges. Under US GAAP, the foreign currency component of a business combination is not eligible for cash flow hedging, and therefore, for the year ended December 31, 2006, the $88 million after-tax gain on the derivative financial instruments would have been included in net earnings. For the year ended December 31, 2008, US GAAP net earnings would have been decreased by $8 million (2007 - $6 million, 2006 - $1 million), net of income taxes of $3 million (2007 - $7 million, 2006 - $1 million), to reflect the impact of higher depletion charges. The 2007 income tax effect includes the effect of enacted Canadian income tax rate changes on this item.

(E) Under Canadian GAAP, the Company began capitalizing interest on the Horizon Project when the Board of Directors approval was received in 2005. For US GAAP, capitalization of interest on projects constructed over time is mandatory and interest would have been capitalized to the costs of construction beginning in 2004. As a result of applying US GAAP, an additional $27 million would have been capitalized to property, plant and equipment in 2004.

(F) Under Canadian GAAP, the Company is not required to include potential common shares related to stock options in the calculation of diluted earnings per share as the Company has recorded the potential settlement of the stock options as a liability. Under US GAAP FAS 128 "earnings per Share", the Company would have included potential common shares related to stock options in the calculation of diluted earnings per share. For the year ended December 31, 2008, no additional shares would have been included in the calculation of diluted earnings per share for US GAAP as the impact would have been anti-dilutive (2007 - 3,376,000 additional shares, 2006 - 8,762,000 additional shares).

(G) Under Canadian GAAP, the effects of income tax changes are recognized when the changes are considered substantively enacted. Under US GAAP, the income tax changes would not be recognized until the changes are enacted into law. For the year ended December 31, 2007, the differences between substantively enacted and enacted tax legislation resulted in a difference in timing of the recognition of a $234 million future income tax recovery.

(H) Effective January 1, 2007, under Canadian GAAP, debt issue costs on long-term debt must be included in the carrying value of the related debt. Under US GAAP, these items must be recorded as a deferred charge. Application of US GAAP would have resulted in the balance sheet reclassification of $55 million of debt issue costs from long-term debt to deferred charges in 2008 (2007 - $51 million). There was no difference from Canadian GAAP prior to 2007.

(I) In September 2006, the FASB issued FAS 157 "Fair Value Measurements" effective for fiscal years beginning after November 15, 2007. The implementation date was subsequently delayed until years beginning on or after November 15, 2008 except for non financial assets and non financial liabilities that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). FAS 157 standardizes the meaning of "Fair Value" in all FASB statements that refer to fair value and expands disclosures about fair value measurements. The adoption of this standard did not result in a Canadian and US GAAP reconciling item.

(J) In February 2007, the FASB issued FAS 159 "The Fair Value Option for Financial Assets and Financial Liabilities" effective for fiscal years beginning after November 15, 2007. FAS 159 allows entities to carry most financial instruments at fair value, even if existing standards would not require this. The adoption of this standard did not result in a US GAAP reconciling item.

(K) In December 2007, the FASB issued FAS 141(R) "Business Combinations", which replaces FAS 141 effective for fiscal years beginning after December 15, 2008. FAS 141(R) retains the purchase method of accounting and requires assets acquired and liabilities assumed in a business combination to be measured at fair value at the date of acquisition. The standard also requires acquisition-related costs and restructuring costs to be recognized separately from the business combination. This standard is to be applied prospectively to all business combinations subsequent to the effective date and does not require restatement of previously completed business combinations.

(L) US GAAP - Recently issued accounting standards

During 2008, the US Securities and Exchange Commission adopted revisions to its oil and gas reporting disclosures contained in regulation S-K and regulation S-X. These revisions change the price basis for calculating oil and gas reserves from a single-day, year-end price to a monthly average price based on "first day of the month" price. These revisions will impact the reserves used in the Company's accounting for depletion and its calculation of the ceiling test under US GAAP. These revisions are effective for filings made on or after January 1, 2010, and will be applied prospectively with no retroactive restatement.

ADDITIONAL DISCLOSURE

DISCLOSURE CONTROLS AND PROCEDURES

As of the end of the registrant's fiscal year ended December 31, 2008, an evaluation of the effectiveness of Canadian Natural's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(c) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") was carried out by Canadian Natural's management with the participation of Canadian Natural's principal executive officer and principal financial officer. Based upon the evaluation, Canadian Natural's principal executive officer and principal financial officer have concluded that as of the end of the fiscal year, Canadian Natural's disclosure controls and procedures are effective to ensure that information required to be disclosed by the registrant in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and (ii) accumulated and communicated to the registrant's management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

It should be noted that while Canadian Natural's principal executive officer and principal financial officer believe that Canadian Natural's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect Canadian Natural's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

The required disclosure is included in the "Management's Assessment of Internal Control Over Financial Reporting" that accompanies Canadian Natural's audited consolidated financial statements for the fiscal year ended December 31, 2008, filed as part of this Annual Report on Form 40-F.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

The required disclosure is included in the "Auditors' Report" that accompanies Canadian Natural's audited consolidated financial statements for the fiscal year ended December 31, 2008, filed as part of this Annual Report on Form 40-F.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

During the fiscal year ended December 31, 2008, there were no changes in Canadian Natural's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, Canadian Natural's internal control over financial reporting.

NOTICES PURSUANT TO REGULATION BTR

None.

AUDIT COMMITTEE FINANCIAL EXPERT

The Board of Directors of Canadian Natural has determined that Ms. C.M. Best qualifies as an "audit committee financial expert" (as defined in paragraph 8(b) of General Instruction B to the Form 40-F) serving on its Audit Committee. Ms. C.M. Best is, as are all members of the Audit Committee of the Board of Directors of Canadian Natural, "independent" as such term is defined in the rules of the New York Stock Exchange.

CODE OF ETHICS

Canadian Natural has a long-standing Code of Integrity, Business Ethics and Conduct (the "Code of Ethics"), which covers such topics as employment standards, conflict of interest, the treatment of confidential information and trading in Canadian Natural's shares and is designed to ensure that Canadian

Natural's business is consistently conducted in a legal and ethical manner. Each director and all employees, including each member of senior management and more specifically the principal executive officer, the principal financial officer and the principal accounting officer, are required to abide by the Code of Ethics. The Nominating and Corporate Governance Committee periodically reviews the Code of Ethics to ensure it addresses appropriate topics and complies with regulatory requirements and recommends any appropriate changes to the Board for approval.

Any waivers of or amendments to the Code of Ethics must be approved by the Board of Directors and will be appropriately disclosed.

The Code of Ethics is available through the System for Electronic Document and Analysis and Retrieval (SEDAR) at www.sedar.com. Requests for copies can also be made by contacting: Bruce E. McGrath, Corporate Secretary, Canadian Natural Resources Limited, 2500-855 2nd Street, S.W., Calgary, Alberta, Canada T2P 4J8.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

PricewaterhouseCoopers LLP ("PwC") has been the auditor of Canadian Natural since Canadian Natural's inception. The aggregate amounts billed by PwC for each of the last two fiscal years for audit fees, audit-related fees, tax fees and all other fees, excluding expenses, are set forth below.

AUDIT FEES

The aggregate fees billed for each of the last two fiscal years of Canadian Natural ending December 31, 2008 and December 31, 2007, for professional services rendered by PwC for the audit of its internal controls and annual consolidated financial statements in connection with statutory and regulatory filings or engagements for those fiscal years, unaudited reviews of the first, second and third quarters of its interim consolidated financial statements and audits of certain of Canadian Natural's subsidiary companies' annual financial statements were $2,685,800 for 2008 and were $2,729,315 for 2007.

AUDIT-RELATED FEES

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2008 and December 31, 2007, for audit-related services by PwC including debt covenant compliance and Crown Royalty Statements, were $156,300 for 2008 and were $164,000 for 2007. Canadian Natural's Audit Committee approved all of these audit-related services.

TAX FEES

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2008 and December 31, 2007, for professional services rendered by PwC for tax-related services related to expatriate personal tax compliance as well as other corporate tax return matters provided in 2008 were $91,500 for 2008 and were $154,459 for 2007. Canadian Natural's Audit Committee approved all of these tax-related services.

ALL OTHER FEES

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2008 and December 31, 2007 for other services were $9,500 for 2008 and were $9,440 for 2007. The fees for other services paid in 2008 related to accessing resource materials through PwC's accounting literature library. Canadian Natural's Audit Committee approved all of the noted services.

AUDIT COMMITTEE PRE-APPROVAL POLICIES AND PROCEDURES

The Audit Committee's duties and responsibilities include the review and approval of fees to be paid to the independent auditors, scope and timing of the audit and other related services rendered by the independent auditors. The Audit

Committee also reviews and approves the independent auditor's annual audit plan, including scope, staffing, locations and reliance upon management and internal audit department prior to the commencement of the audit and reviews and approves proposed non-audit services to be provided by the independent auditors, except those non-audit services prohibited by legislation. Canadian Natural did not rely on the de minimis exemption provided by paragraph (c)(7)(i)(c) of Rule 2.01 of Regulation S-X in 2008.

OFF BALANCE SHEET ARRANGEMENTS

Canadian Natural does not have any off-balance sheet arrangements that have or are reasonably likely to have an effect on its results of operations or financial condition. See page 60 of Canadian Natural's Management's Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2008, filed herewith, under the caption "Commitments and Off Balance Sheet Arrangements".

CONTRACTUAL OBLIGATIONS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. These commitments primarily relate to firm commitments for gathering, processing and transmission services; operating leases relating to offshore FPSOs, drilling rigs and office space; expenditures relating to ARO; as well as long-term debt and interest payments. As at December 31, 2008, no entities were consolidated under CICA Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2008:

($ millions)	2009	2010	2011	2012	2013	Thereafter
Product transportation and pipeline	$ 219	$ 184	$ 159	$ 133	$ 124	$ 1,175
Offshore equipment operating lease	$ 175	$ 145	$ 144	$ 116	$ 117	$ 398
Offshore drilling	$ 251	$ 62	$ -	$ -	$ -	$ -
Asset retirement obligations (1)	$ 6	$ 7	$ 6	$ 6	$ 6	$ 4,443
Long-term debt (2)	$ 2,385	$ 400	$ 490	$ 429	$ 890	$ 6,707
Interest expense (3)	$ 610	$ 565	$ 543	$ 490	$ 428	$ 5,992
Office lease	$ 25	$ 29	$ 23	$ 2	$ 2	$ 1
Other	$ 321	$ 180	$ 17	$ 12	$ 8	$ 19

(1) Amounts represent management's estimate of the future undiscounted payments to settle ARO related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2009 - 2013 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(2) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,725 million of revolving bank credit facilities due to the extendable nature of the facilities.

(3) Interest expense amounts represent the scheduled fixed rate and variable rate cash payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates as of December 31, 2008.

IDENTIFICATION OF THE AUDIT COMMITTEE

Canadian Natural has a separately designated standing audit committee established in accordance with section 3(a)(58)(A) of the Exchange Act. The members of the Audit Committee are Messrs. G. A. Filmon, G. D. Giffin, D. A. Tuer and Ms. C.M. Best, who chairs the Audit Committee.

NEW YORK STOCK EXCHANGE DISCLOSURE

Presiding Director at Meetings of Non-Management Directors

Canadian Natural schedules executive sessions at each regularly scheduled Board of Directors meeting in which Canadian Natural's "non-management directors" (as that term is defined in the rules of the New York Stock Exchange) meet without management participation. Mr. G. D. Giffin serves as the presiding director (the "Presiding Director") at such sessions and in his absence the non-management directors appoint a Presiding Director from among the non-management directors.

Communication with Non-Management Directors

Shareholders may send communications to Canadian Natural's non-management directors by writing to the Presiding Director, c/o Bruce E. McGrath, Corporate Secretary, Canadian Natural Resources Limited, 2500, 855 - 2nd Street S.W., Calgary, Alberta, T2P 4J8. Communications will be referred to the Presiding Director for appropriate action. The status of all outstanding concerns addressed to the Presiding Director will be reported to the Board of Directors as appropriate.

Corporate Governance Guidelines

In accordance with Section 303A.09 of the NYSE Listed Company Manual, Canadian Natural has adopted a set of corporate governance guidelines, which are available in print at no charge to any shareholder who requests them. Requests for copies of the corporate governance guidelines should be made by contacting: Bruce E. McGrath, Corporate Secretary, Canadian Natural Resources Limited, 2500-855 2nd Street, S.W., Calgary, Alberta, Canada T2P 4J8. The corporate governance guidelines are attached as a schedule to the Information Circular for the Annual General Meeting of Shareholders which is available through the System for Electronic Document and Analysis and Retrieval (SEDAR) at www.sedar.com.

Board Committee Charters

The charters of Canadian Natural's Audit Committee, Nominating and Corporate Governance Committee and Compensation Committee are available in print at no charge to any shareholder who requests them. Requests for copies of these documents should be made by contacting: Bruce E. McGrath, Corporate Secretary, Canadian Natural Resources Limited, 2500-855 2nd Street, S.W., Calgary, Alberta, Canada T2P 4J8. The Charter of Canadian Natural's Audit Committee is also attached as a schedule to Canadian Natural's Annual Information Form for year ending December 31, 2008, which forms part of this Form 40-F. The Annual Information Form is also available through the System for Electronic Document and Analysis and Retrieval (SEDAR) at www.sedar.com.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

UNDERTAKING

Canadian Natural undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

CONSENT TO SERVICE OF PROCESS

Canadian Natural has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

Any change to the name or address of the agent for service of process of Canadian Natural shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the relevant registration statement.

SIGNATURES

Pursuant to the requirements of the Exchange Act, Canadian Natural certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report to be signed on its behalf by the undersigned, thereto duly authorized.

Dated this 25th day of March, 2009.

CANADIAN NATURAL RESOURCES LIMITED

By: SIGNED "STEVE W. LAUT"

Name: Steve W. Laut
Title: President and Chief Operating Officer

Documents filed as part of this report:

EXHIBIT INDEX

Exhibit No.	Description
1.	Supplementary Oil & Gas Information for the fiscal year ended December 31, 2008.
2.	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.
3.	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.
4.	Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).

5. Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).

6. Consent of PricewaterhouseCoopers LLP, independent chartered accountants.

7. Consent of Sproule Associates Limited, independent petroleum engineering consultants.

8. Consent of GLJ Petroleum Consultants Ltd., independent petroleum engineering consultants.

EXHIBIT 1

SUPPLEMENTARY OIL & GAS INFORMATION FOR
THE FISCAL YEAR ENDED DECEMBER 31, 2008

SUPPLEMENTARY OIL & GAS INFORMATION (unaudited)

This supplementary crude oil and natural gas information is provided in accordance with the United States Financial Accounting Standards Board Statement 69 ("FAS 69"), "Disclosures about Oil and Gas Producing Activities", and where applicable is reconciled to the financial information prepared in accordance with generally accepted accounting principles in the United States ("US GAAP").

NET PROVED CRUDE OIL AND NATURAL GAS RESERVES

The Company retains qualified independent reserves evaluators to evaluate the Company's proved crude oil and natural gas reserves.

o For the year ended December 31, 2008, the reports by Sproule Associates Limited ("Sproule") covered 100% of the Company's conventional reserves.

o For the years ended December 31, 2007, 2006, and 2005 the reports by Sproule and Ryder Scott Company covered 100% of the Company's conventional reserves.

Proved crude oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids ("NGLs") that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Estimates of crude oil and natural gas reserves are subject to uncertainty and will change as additional information regarding producing fields and technology becomes available and as future economic and operating conditions change.

The following table summarizes the Company's proved and proved developed conventional crude oil and natural gas reserves, net of royalties, as at December 31, 2008, 2007, 2006, and 2005:

	North	North

Crude oil and NGLs (mmbbl)	America	Sea
Net proved reserves Reserves, December 31, 2005	694	290
Extensions and discoveries	53	3
Improved recovery	190	26
Purchases of reserves in place	26	-
Sales of reserves in place	-	-
Production	(75)	(22)
Revisions of prior estimates (1)	(1)	2
Reserves, December 31, 2006	887	299
Extensions and discoveries	30	-
Improved recovery	13	6
Purchases of reserves in place	1	-
Sales of reserves in place	-	(3)
Production	(77)	(20)
Revisions of prior estimates (1)	66	28
Reserves, December 31, 2007	920	310
Extensions and discoveries	51	-
Improved recovery	17	6
Purchases of reserves in place	-	-
Sales of reserves in place	-	-
Production	(76)	(17)
Economic revisions due to prices	28	(81)
Revisions of prior estimates	8	38
Reserves, December 31, 2008	948	256
Net proved developed reserves		
December 31, 2005	402	214
December 31, 2006	420	214
December 31, 2007	426	240
December 31, 2008	428	97

(1) Revisions of prior estimates for the years ended December 31, 2007 and 2006 include the impact of economic revisions due to prices.

Natural gas (bcf)	North America	North Sea
Net proved reserves		
Reserves, December 31, 2005	2,741	29
Extensions and discoveries	250	-
Improved recovery	74	-
Purchases of reserves in place	1,111	-
Sales of reserves in place	(1)	-
Production	(433)	(5)
Revisions of prior estimates (1)	(37)	13
Reserves, December 31, 2006	3,705	37
Extensions and discoveries	134	-
Improved recovery	132	3
Purchases of reserves in place	12	-

Sales of reserves in place	-	-
Production	(503)	(5)
Revisions of prior estimates (1)	41	46
Reserves, December 31, 2007	3,521	81
Extensions and discoveries	140	-
Improved recovery	52	(1)
Purchases of reserves in place	77	-
Sales of reserves in place	(1)	-
Production	(449)	(4)
Economic revisions due to prices	(19)	(56)
Revisions of prior estimates	202	47
Reserves, December 31, 2008	3,523	67
Net proved developed reserves		
December 31, 2005	2,300	16
December 31, 2006	2,934	17
December 31, 2007	2,731	58
December 31, 2008	2,690	45

(1) Revisions of prior estimates for the years ended December 31, 2007 and 2006 include the impact of economic revisions due to prices.

CAPITALIZED COSTS RELATED TO CRUDE OIL AND NATURAL GAS ACTIVITIES

2008			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa
Proved properties	$ 34,386	$ 4,155	$ 2,076
Unproved properties	2,271	12	595
	36,657	4,167	2,671
Less: accumulated depletion and depreciation	(21,857)	(3,366)	(777)
Net capitalized costs	$ 14,800	$ 801	$ 1,894

2007			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa
Proved properties	$ 32,061	$ 3,164	$ 1,695
Unproved properties	2,259	10	138
	34,320	3,174	1,833
Less: accumulated depletion and depreciation	(12,213)	(1,446)	(645)
Net capitalized costs	$ 22,107	$ 1,728	$ 1,188

	2006		
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa
Proved properties	$ 29,596	$ 3,346	$ 1,601
Unproved properties	2,244	24	84
	31,840	3,370	1,685
Less: accumulated depletion and depreciation	(9,878)	(1,341)	(481)
Net capitalized costs	$ 21,962	$ 2,029	$ 1,204

COSTS INCURRED IN CRUDE OIL AND NATURAL GAS ACTIVITIES

	2008		
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa
Property acquisitions			
Proved	$ 299	$ (7)	$ 44
Unproved	84	1	1
Exploration	144	3	-
Development	1,810	195	772
Costs incurred	$ 2,337	$ 192	$ 817

	2007		
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa
Property acquisitions			
Proved	$ 55	$ (38)	$ -
Unproved	13	1	-
Exploration	239	19	-
Development	2,173	380	148
Costs incurred	$ 2,480	$ 362	$ 148

	2006		
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa
Property acquisitions			
Proved	$ 5,627	$ -	$ 1
Unproved	910	-	-
Exploration	238	4	1

Development	2,807	628	133
Costs incurred	$ 9,582	$ 632	$ 135

RESULTS OF OPERATIONS FROM CRUDE OIL AND NATURAL GAS PRODUCING ACTIVITIES

The Company's results of operations from crude oil and natural gas producing activities for the years ended December 31, 2008, 2007, and 2006 are summarized in the following tables:

		2008	
(millions of Canadian dollars)	North America	North Sea	
Crude oil and natural gas revenue, net of royalties and blending costs	$ 8,126	$ 1,731	$
Production	(1,881)	(457)	
Transportation	(327)	(10)	
Depletion, depreciation and amortization (1)	(9,661)	(1,564)	
Asset retirement obligation accretion	(42)	(27)	
Petroleum revenue tax	-	(143)	
Income tax	1,128	235	
Results of operations	$ (2,657)	$ (235)	$

(1) Includes the impact of a ceiling test impairt December 31, 2008 of $8,665 million, pre-tax.

			2007
(millions of Canadian dollars)	North America	North Sea	
Crude oil and natural gas revenue, net of royalties and blending costs	$ 7,441	$ 1,522	$
Production	(1,642)	(432)	
Transportation	(335)	(16)	
Depletion, depreciation and amortization	(2,359)	(340)	
Asset retirement obligation accretion	(38)	(30)	
Petroleum revenue tax	-	(141)	
Income tax	(997)	(282)	
Results of operations	$ 2,070	$ 281	$

		2006
(millions of Canadian dollars)	North America	North Sea

Crude oil and natural gas revenue, net of royalties and blending costs	$ 5,707	$ 1,310	$
Production	(1,436)	(390)	
Transportation	(326)	(15)	
Depletion, depreciation and amortization	(1,894)	(297)	
Asset retirement obligation accretion	(35)	(31)	
Petroleum revenue tax	-	(234)	
Income tax	(706)	(172)	
Results of operations	$ 1,310	$ 171	$

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS FROM PROVED CRUDE OIL AND NATURAL GAS RESERVES AND CHANGES THEREIN

The following standardized measure of discounted future net cash flows from proved crude oil and natural gas reserves has been computed using year-end sales prices and costs and year-end statutory income tax rates. A discount factor of 10% has been applied in determining the standardized measure of discounted future net cash flows. The Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair value of the crude oil and natural gas properties. Actual net cash flows will differ from the presented estimated future net cash flows due to several factors including:

- Future production will include production not only from proved properties, but may also include production from probable and possible reserves;
- Future production of crude oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future rather than year-end sales prices and costs will apply;
- Economic factors such as interest rates, income tax rates, regulatory and fiscal environments and operating conditions will change;
- Future estimated income taxes do not take into account the effects of future exploration expenditures; and
- Future development and asset retirement obligations will differ from those estimated.

Future net revenues, development, production and restoration costs have been based upon the estimates referred to above. The following tables summarize the Company's future net cash flows relating to proved crude oil and natural gas reserves based on the standardized measure as prescribed in FAS 69:

		2008	
(millions of Canadian dollars)	North America	North Sea	
Future cash inflows	$ 51,913	$ 13,681	$
Future production costs	(23,747)	(6,845)	
Future development and asset retirement obligations	(9,238)	(4,674)	
Future income taxes	(3,097)	(2,011)	
Future net cash flows	15,831	151	

10% annual discount for timing of future cash flows	(6,872)	(76)	
Standardized measure of future net cash flows	$ 8,959	$ 75	$

		2007
(millions of Canadian dollars)	North America	North Sea
Future cash inflows	$ 71,069	$ 30,269
Future production costs	(23,729)	(9,316)
Future development and asset retirement obligations	(7,938)	(4,021)
Future income taxes	(9,508)	(11,376)
Future net cash flows	29,894	5,556
10% annual discount for timing of future cash flows	(13,952)	(2,176)
Standardized measure of future net cash flows	$ 15,942	$ 3,380

		200
(millions of Canadian dollars)	North America	North Sea
Future cash inflows	$ 63,368	$ 20,815
Future production costs	(21,634)	(8,077)
Future development and asset retirement obligations	(7,029)	(4,348)
Future income taxes	(9,118)	(5,623)
Future net cash flows	25,587	2,767
10% annual discount for timing of future cash flows	(11,214)	(956)
Standardized measure of future net cash flows	$ 14,373	$ 1,811

The principal sources of change in the standardized measure of discounted future net cash flows are summarized in the following table:

(millions of Canadian dollars)	2008	20
Sales of crude oil and natural gas produced, net of production costs	$ (9,679)	$ (7,
Net changes in sales prices and production costs	(14,680)	7,

Extensions, discoveries and improved recovery	820	1,
Changes in estimated future development costs	(715)	(
Purchases of proved reserves in place	113	
Sales of proved reserves in place	(1)	(
Revisions of previous reserve estimates	112	2,
Accretion of discount	3,468	2,
Changes in production timing and other	767	
Net change in income taxes	8,462	(3,
Net change	(11,333)	3,
Balance - beginning of year	21,720	17,
Balance - end of year	$ 10,387	$ 21,

EXHIBIT 2

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO RULE 13A-14(A) OR 15D-14 OF THE SECURITIES EXCHANGE ACT OF 1934

CERTIFICATION

I, Steve W. Laut, certify that:

1. I have reviewed this annual report on Form 40-F of Canadian Natural Resources Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13(a) - 15(f) and 15d -15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of issuer's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated this 25th day of March, 2009.

SIGNED " STEVE W. LAUT"

Steve W. Laut
President and Chief Operating Officer (Principal Executive Officer),
Canadian Natural Resources Limited

EXHIBIT 3

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO RULE 13A-14(A) OR 15D-14 OF THE SECURITIES EXCHANGE ACT OF 1934

CERTIFICATION

I, Douglas A. Proll, certify that:

1. I have reviewed this annual report on Form 40-F of Canadian Natural Resources Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial

information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13(a) - 15(f) and 15d -15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusion about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated this 25th day of March, 2009.

SIGNED "DOUGLAS A. PROLL"

Douglas A. Proll
Chief Financial Officer and Senior Vice-President, Finance
(Principal Financial Officer),
Canadian Natural Resources Limited

EXHIBIT 4

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO SECTION 1350 OF CHAPTER 63 OF TITLE 18 OF THE UNITED STATES CODE (18 U.S.C. 1350)

In connection with the report of Canadian Natural Resources Limited (the "Company") on the Form 40-F for the fiscal year ending December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Steve W. Laut, certify pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

DATED this 25th day of March, 2009.

SIGNED "STEVE W. LAUT"

Steve W. Laut
President and Chief Operating Officer (Principal Executive Officer),
Canadian Natural Resources Limited

EXHIBIT 5

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO SECTION 1350 OF CHAPTER 63 OF TITLE 18 OF THE UNITED STATES CODE (18 U.S.C. 1350)

In connection with the report of Canadian Natural Resources Limited (the "Company") on the Form 40-F for the fiscal year ending December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Douglas A. Proll, certify pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

DATED this 25th day of March, 2009.

SIGNED "DOUGLAS A. PROLL"

Douglas A. Proll
Chief Operating Officer and Senior Vice-President, Finance
(Principal Financial Officer),
Canadian Natural Resources Limited

EXHIBIT 6

CONSENT OF PRICEWATERHOUSECOOPERS LLP, INDEPENDENT CHARTERED ACCOUNTANTS

We hereby consent to (i) the inclusion in Canadian Natural Resources Limited's Annual Report on Form 40-F for the year ended December 31, 2008; and (ii) the incorporation by reference in the registration statement on Form F-9 (File No. 333-146056), of our audit report dated March 4, 2009 on the consolidated balance sheets of Canadian Natural Resources Limited as at December 31, 2008 and 2007, and the consolidated statements of earnings, shareholder's equity, comprehensive income and cash flows for each of the years in the three-year period ended December 31, 2008 and the effectiveness of internal control over financial reporting of Canadian Natural Resources Limited as of December 31, 2008.

Calgary, Alberta
March 25, 2009

EXHIBIT 7

CONSENT OF SPROULE ASSOCIATES LIMITED,
INDEPENDENT PETROLEUM ENGINEERING CONSULTANTS

We consent to the use of our report with respect to the reserves data of Canadian Natural Resources Limited incorporated by reference in its (i) Annual Report (Form 40-F) for the year ended December 31, 2008 and (ii) Registration Statement on Form F-9 (Registration No. 333-146056) filed with the Securities and Exchange Commission.

SIGNED "SPROULE ASSOCIATES LIMITED"

Calgary, Alberta
March 25, 2009

EXHIBIT 8

CONSENT OF GLJ PETROLEUM CONSULTANTS LTD.,
INDEPENDENT PETROLEUM ENGINEERING CONSULTANTS

We consent to the use of our report with respect to the reserves data of Canadian Natural Resources Limited incorporated by reference in its (i) Annual

Report (From 40-F) for the year ended December 31, 2008 and (ii) Registration Statement on Form F-9 (Registration No. 333-146056) filed with the Securities and Exchange Commission.

SIGNED "GLJ PETROLEUM CONSULTANTS LTD."

Calgary, Alberta
March 25, 2009