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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, 2007 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.
539,728,829 Common Shares outstanding as of December 31, 2007

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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, 2008, the noon buying rate for Canadian Dollars as expressed by the Federal Reserve Bank of New York was US$1.0180 equals C$ 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, 2007.

B. AUDITED ANNUAL FINANCIAL STATEMENTS

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2007 and 2006, 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 17 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, 2007.

SUPPLEMENTARY OIL & GAS INFORMATION

For Canadian Natural's Supplementary Oil & Gas Information for the year ended December 31, 20007, see Exhibit 1 of this Annual Report on Form 40-F.

CANADIAN NATURAL RESOURCES LIMITED

ANNUAL INFORMATION FORM

MARCH 27, 2008

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DEFINITIONS

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

"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 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 and medium crude oil, heavy crude oil, thermal in-situ, natural gas, coal bed methane and natural gas liquid activities. It does not include the Company's oil sands mining assets

"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 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

"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. 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. In addition, 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 assurance that the plans, initiatives or expectations upon which they are based will occur.

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 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 interdependent 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, 2007, the Company retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule") and Ryder Scott Company ("Ryder Scott") 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 includes all of the Company's light/medium, primary heavy, and thermal crude oil, natural gas, coal bed methane and NGLs activities. It does not include the Company's oil sands mining assets. Conventional crude oil, NGLs, and natural gas reserves, net of royalties, are estimated using royalty regulations in effect as of December 31, 2007. Similarly, bitumen and synthetic crude oil reserves, net of royalties, relating to surface mineable oil sand projects are estimated using royalty regulations in effect as of December 31, 2007. Royalty changes proposed by the Government of Alberta will be incorporated in the reserves evaluation should they be enacted. Sproule evaluated the Company's North America conventional assets and Ryder Scott evaluated the international conventional assets. The Company has been granted an exemption from 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 reserve reconciliation net of royalties in adherence to SEC requirements.

For the year ended December 31, 2007, 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. 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 voluntary additional 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. Only 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 voluntary additional information, which is disclosed in this Annual Information Form.

The Reserve Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of Sproule, Ryder Scott 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

Management's Discussion and Analysis ("MD&A") 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.

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. Fluctuations 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 and prices of alternate sources of energy, including 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 or curtailment in production at some properties or resulting 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 prices decline, the carrying value of the assets could be subject to downward revisions, and net earnings could be adversely affected.

Approximately 26% of the Company's 2007 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 higher transportation and refining costs associated with heavy crude oil. 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 differentials are uncertain and any increase in the heavy crude oil differentials could have a material adverse effect on the Company's business.

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 may have an adverse effect on the Company's future net earnings and cash flow from operations.

GREENHOUSE GAS AND OTHER AIR EMISSIONS

The Company is concurrently 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 emission reductions 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 CO2e annually. Two Canadian Natural facilities, the Primrose/Wolf Lake in-situ heavy oil and the Hays sour gas plant, are captured under the regulations. 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 CO2 allocation. For Phase 2 (2008-2012) the Company's CO2 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 of its major facilities to reduce CO2 emissions and on trading mechanisms to ensure compliance with any requirement 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 common 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, CO2 capture and sequestration in oil sands tailings, CO2 capture and storage in association with enhanced oil recovery and participation in an industry initiative to promote an integrated CO2 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 participation of the Company and the industry with stakeholders, guidelines have been developed that adopt a structured process to emission reductions that is commensurate with technological development and operational requirements.

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.

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 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 will include integrated oil and natural gas companies and numerous other senior oil and natural gas companies, some of which may have greater financial and other resources than the Company.

OTHER BUSINESS RISKS

Other business risks relate to operational risks, the cost of capital available to fund exploration and development programs, fluctuation in foreign exchange rates, the availability of skilled labour and manpower, regulatory issues and taxation and the requirements of new environmental laws and regulations. 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 to mitigate physical risks. The Company also mitigates insurable risks to protect against significant losses by maintaining a comprehensive insurance program, while maintaining levels and amounts of risk within the Company which management believes to be acceptable. 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 private ownership of crude oil and natural gas properties in Canada differs distinctly from its ownership interests in 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 outside of Canada 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.

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, 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.

PRIORITY OF SUBSIDIARY INDEBTEDNESS; CONSEQUENCES OF HOLDING CORPORATION STRUCTURE

The Company carries on business through corporate and partnership subsidiaries. The majority of the Company's assets are held in one or more corporate or partnership subsidiaries. The results of operations and ability to service indebtedness, including debt securities, are dependent upon the results of operations of these subsidiaries and the payment of funds by these subsidiaries 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 or partnership subsidiary, 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.

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 is 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 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.

On October 25, 2007 the Province of Alberta issued the framework of its proposed changes to the Alberta crude oil and natural gas royalty regime, effective January 1, 2009. The Company is currently awaiting finalization of the royalty implementation regulations, however it expects that its 2009 and future Alberta royalty payments will increase as a result of the proposed royalty changes and that its level of activity in Alberta in aggregate will be reduced from what it otherwise would have been in the absence of such royalty changes.

In addition to government royalties, the Company is currently subject to federal and provincial income taxes in Canada at a combined rate of approximately 32.53% after allowable deductions.

During 2007, the Canadian Federal Government enacted income tax rate changes which reduce the Federal corporate income tax rate over the next five years from 21% in 2007 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.

The Company is subject to UK Corporation Tax ("CT") on its UK profits as adjusted for CT purposes. PRT paid is deductible for CT purposes. The CT rate, which became effective April 1, 1999, was set at 30%. In its 2002 budget speech by the UK Chancellor of the Exchequer, the UK Government announced changes to taxation policies on UK North Sea crude oil and natural gas production. A Supplementary Charge Tax ("SCT") of 10%, charged on the same profits as calculated for "normal" CT but excluding any deduction for financing costs, was added to the current 30% CT charge. Also the deduction for expenditures on capital items was changed from 25% per annum to 100% in the year incurred. During 2005, the UK Chancellor of the Exchequer announced a further increase to the SCT of 10% to 20% on profits from UK North Sea crude oil and natural gas production, effective January 1, 2006. In December 2006, the UK Government announced the abolition of PRT on profits of decommissioned fields subsequently redeveloped, subject to certain conditions being met.

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 on CI-26 and the Baobab Field on CI-40, in Cote d'Ivoire, are subject to production sharing arrangements that provide that tax or royalty payments to the Government are deemed to be met from the Government's share of profit oil. In August 2006, the Government of Cote d'Ivoire announced a reduction in the rate of Corporate Income Tax from 35% to 27%, effective January 1, 2006. Effective January 1, 2008, the Government of Cote d'Ivoire announced a further corporate income tax rate reduction to 25%.

In October 2005, Canadian Natural completed the acquisition of the permit to develop the Olowi Field, offshore Gabon and received approval of its development plan for this acquisition from the Gabonese Government in early 2006 and from Canadian Natural's Board of Directors in November 2006. Development of this field is under the terms of a production sharing arrangement that provides that tax or royalty payments to the Government are deemed to be met from the Government's share of profit oil.

ENVIRONMENTAL MATTERS

The Company carries out its activities in compliance with all relevant regional, national and international regulations and industry standards. Environmental specialists in the UK and Canada 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. At present, 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 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 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: using water-based, environmentally friendly drilling muds whenever possible; implementing cost effective ways of reducing

GHG per unit of production; exercising care with respect to all waste produced through effective waste management plans; 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. 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.

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 2007 the Company completed approximately 115 gas conservation projects, resulting in a reduction of 1.28 million tonnes/year of CO2e. Over the past five years the Company has spent over $116 million to conserve the equivalent of over 6.4 million tonnes of CO2e. In heavy crude oil production Canadian Natural is evaluating tank heater efficiencies in an effort to conserve fuel gas at facilities with field tanks. The Company also monitors the performance of its compressor fleet and it is continually modified and optimized for maximum efficiency. These programs also influence and direct the Company's plans for new projects and facilities. It is planned that the Horizon Project will incorporate advancements in technology to reduce further 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 CO2 capture and the sequestration of CO2 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. The Produced Water Re-injection trial on Ninian Central continued throughout 2007 during which time approximately 1.5 million cubic meters of produced water were re-injected to the reservoir. This resulted in approximately 16 tonnes of oil not being discharged to sea, a reduction of approximately 10%. The trial has been very successful and will continue through 2008 as a permanent installation.

The costs incurred by the Company for compliance with environmental matters and site restoration is approximately 3% of the total exploration and development expenditures incurred by the Company in each of the years ended December 31, 2007, 2006 and 2005.

For 2007, the Company's capital expenditures included $71 million for abandonment expenditures (2006 - $75 million; 2005 - $46 million).

The Company's estimated undiscounted ARO at December 31, 2007 was as follows:

Estimated ARO, undiscounted ($millions)	2007	2006
North America	$ 3,038	$ 2,826
North Sea	1,286	1,543
Offshore West Africa	102	128
	4,426	4,497
North Sea PRT recovery	(555)	(625)
	$ 3,871	$ 3,872

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 expected to result in an estimated PRT recovery of $555 million (2006 - $625 million; 2005 - $370 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 $3,871 million (2006 - $3,872 million).

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 September 14, 2006, the Company announced entering into an agreement to acquire Anadarko Canada Corporation, a subsidiary of Anadarko Petroleum Corporation for net cash consideration of $4,641 million including working capital and other adjustments. Pursuant to a Purchase and Sale Agreement, the Company acquired all of the outstanding shares of Anadarko Canada Corporation effective November 2, 2006. 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. Subsequently, on January 1, 2007, ACC-CNR Resources Corporation and Canadian Natural Resources Limited amalgamated and the amalgamated company continued 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 of the Company, each of which is directly or indirectly wholly-owned, and their jurisdictions of incorporation are as follows:

NAME OF COMPANY	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

Canadian Natural, as the managing partner and CNR (ECHO) Resources Inc. are the partners of Canadian Natural Resources, a general partnership. Canadian Natural, as the managing partner, CNR (ECHO) Resources Inc., and Canadian Natural Resources are partners of Canadian Natural Resources Northern Alberta Partnership, a general partnership. The two partnerships hold the majority of the producing Canadian crude oil and natural gas properties of Canadian Natural. Canadian Natural, as the managing partner, and CNR Petro Resources Limited are the partners of CNR 2006 Partnership, which holds certain crude oil and natural gas properties situated in the provinces of Alberta, Saskatchewan and British Columbia and in the Yukon Territories. The Company also has a 15% interest in Cold Lake Pipeline Ltd., which is the general partner of Cold Lake Pipeline Limited Partnership in which Canadian Natural holds a separate 14.7% partnership interest. Canadian Natural, as the managing partner, and CNR (ECHO) Resources Inc. are the partners of Canadian Natural Resources 2005 Partnership, a general partnership which holds certain natural gas facilities situated in Alberta.

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

Canadian Natural's business is the acquisition of interests in crude oil and natural gas rights and the exploration, development, production, marketing and sale of crude oil and NGLs, natural gas and bitumen production.

The Company initiates, operates and maintains a large working interest in a majority of the prospects in which it participates. Canadian Natural's objective is to increase cash flow and net earnings through the development of its existing crude oil and natural gas properties and through the discovery and acquisition of new reserves. The Company's principal regions of crude oil and natural gas operations are in the Western Canadian Sedimentary Basin, the United Kingdom (the "UK") sector of the North Sea and Offshore West Africa. The Company has a full complement of management, technical and support staff to pursue these objectives. As at December 31, 2007 the Company had 3,461 permanent employees in North America and 334 permanent employees in its international operations.

In February 2005, the Board of Directors of the Company approved Phase 1 of the Horizon Project. The Horizon Project is designed as a phased development and includes the mining of bitumen combined with an onsite upgrader. The phased approach provides the Company with improved cost and project controls including labour and materials management, and directionally mitigates the effects of growth on local infrastructure. Phase 1 production is targeted to begin in the third quarter 2008 ramping up to 110,000 bbl/d of SCO. The Company is also developing various cost effective options for execution of additional construction on Phases 2/3. These phases have been further subdivided into four distinct tranches that will target production expansion to 232,000 bbl/d of SCO by 2013.

Based upon stratigraphic drilling and the Company's own internal estimates it is believed that the Company's oil sands leases located near Fort McMurray, Alberta contain an estimated 6 billion barrels of potentially recoverable bitumen using existing mining and upgrading technologies. Additional in-situ potential also exists on the western portions of the leases. The first three phases of the Horizon Project, which encompasses only a portion of these oil sands leases, will deliver approximately 39 years of production without the declines normally associated with petroleum operations. GLJ Petroleum Consultants Ltd. ("GLJ"), a qualified independent third party petroleum consultant firm, was retained by the Reserves Committee of Canadian Natural's Board of Directors to evaluate the mining reserves associated with the Horizon Project. Their report estimated that 3.0 billion barrels of gross lease proved and probable synthetic crude oil reserves are located on the leases associated with the first three phases of the Horizon Project.

In August 2005, the Company entered into an agreement to obtain pipeline transportation service for the Horizon Project. This agreement allows Canadian Natural to gain access to major sales pipelines out of Edmonton for the Company's synthetic crude oil which will be produced at the Horizon Project, while at the same time provides significant quality benefits associated with being the only shipper on the Horizon Pipeline. The expected twinning of the existing Alberta Oil Sands Pipeline ("AOSPL"), resulting in two parallel pipelines, one of which will be dedicated to Canadian Natural, combined with a 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. The initial term of the agreement is 25 years, which will commence on the in-service date. In addition to having the option to renew the agreement for successive 10-year terms, Canadian Natural has the right to request incremental expansions of the Horizon Pipeline based upon applicable National Energy Board approved multi-pipeline economics. The construction of the Horizon Pipeline began in 2006 and is scheduled to be fully operational by third quarter 2008 to coincide with first production at the Horizon Project.

In April 2005, the Company monetized, through a sale, a large portion of its overriding royalty interests on various producing properties throughout Western Canada and Ontario for proceeds of approximately $345 million. In 2004 these interests produced approximately 3,700 boe/d and over the 2003 and 2004 fiscal years cash flow from these interests averaged approximately $50 million per year. As part of the transaction, the Company purchased 3,858,520 trust units of Freehold Royalty trust for $60 million and, after the mandatory hold period and pursuant to an agreement, the trust units were sold to an underwriting group for a net gain of approximately $11 million.

On June 1, 2005, the Company issued $400 million of 10 year 4.95% unsecured notes maturing June 1, 2015 pursuant to a short form shelf prospectus dated August 1, 2003 for the issuance of medium term notes in Canada.

During 2005, the Company completed 96 transactions in the normal course to acquire additional interests in crude oil and natural gas properties at an aggregate net expenditure of $134 million. These properties are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. In addition, the Company disposed of a large portion of its overriding royalty interests and operated and non-operated properties not located in the Company's core regions for proceeds of $454 million.

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.

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 of $4,755 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 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.

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.

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.

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.

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.

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 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, NGLs, light/medium crude oil, Pelican Lake crude oil, 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 45% of 2007 production. Virtually all of the Company's natural gas and NGLs production is located in the Canadian provinces of Alberta and British Columbia and is marketed in Canada and the United States. Light/medium crude oil and NGLs, representing 23% of 2007 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 26% of 2007 production. Other heavy crude oil, which accounts for 6% of 2007 production, is produced from the Pelican Lake area in north Alberta. This production, which has medium crude oil netback characteristics, 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 heavy and Pelican Lake crude oil operations. Canadian Natural expects its ownership of oil sands leases near Fort McMurray, Alberta to provide a basis for long-term synthetic crude oil production growth. The first three phases of the Horizon Project, which encompasses only a portion of these oil sands leases, are targeted to deliver approximately 37 years of synthetic crude oil production.

With approximately 12.7 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

Set forth below is a summary of the principal crude oil, natural gas and oil sands properties as at December 31, 2007. The information reflects the working interests owned by the Company. FPSO's, included under major infrastructure, are leased by the Company under varying terms.

<TABLE>
<CAPTION>

2007 Average Daily Production Rates		Year Ended Dec 31, 2007	Major Infrastructure As at Dec 31, 2007	
Region	Crude oil & NGLs (mbbl)	Natural gas (mmcf)	Undeveloped acreage (thousands)	Batteries/ Compressors & Plants/ Platforms/ FPSO
<S>	<C>	<C>	<C>	<C>
NORTH AMERICA				
Northeast British Columbia	7.0	430	2,401	1/11/-/-
Northwest Alberta	17.0	596	1,489	-/14/-/-
Northern Plains	201.4	418	7,109	12/6/-/-
Southern Plains	12.7	196	925	-/3/-/-
Southeast Saskatchewan	8.4	2	121	-/-/-/-
Non-core regions	0.3	1	109	-/-/-/-
Horizon Oil Sands	-	-	115	-/-/-/-
INTERNATIONAL				
North Sea UK Sector	55.9	13	287	-/-/5/1
Offshore West Africa				
Cote d'Ivoire	28.5	12	55	-/-/-/2
Gabon	-	-	151	-/-/-/-
Non-core regions				
South Africa	-	-	4,002	-/-/-/-
TOTAL	331.2	1,668	16,764	13/34/5/3

</TABLE>

DRILLING ACTIVITY

Set forth below is a summary of the drilling activity, excluding stratigraphic test and service wells, of the Company for each of the last three fiscal years ending December 31, 2007 by geographic region:

<TABLE>
<CAPTION>
2007

	Net exploratory			Net development		
	Productive	Dry holes	Total	Productive	Dry holes	Total
<S>	<C>	<C>	<C>	<C>	<C>	<C>
CANADA						
Northeast British Columbia	7.0	6.0	13.0	38.0	10.1	48.1
Northwest Alberta	17.4	3.8	21.2	94.2	8.9	103.1
Northern Plains	48.5	19.4	67.9	571.5	42.4	613.9
Southern Plains	14.4	1.0	15.4	152.2	0.6	152.8
Southeast Saskatchewan	1.0	-	1.0	23.0	0.4	23.4
Non-core regions	-	-	-	-	-	-
NORTH SEA UK SECTOR	-	-	-	3.7	-	3.7
OFFSHORE WEST AFRICA						
Cote d'Ivoire	-	-	-	4.1	-	4.1
TOTAL	88.3	30.2	118.5	886.7	62.4	949.1

<CAPTION>
2006

	Net exploratory			Net development		
	Productive	Dry holes	Total	Productive	Dry holes	Total
<S>	<C>	<C>	<C>	<C>	<C>	<C>
CANADA						
Northeast British Columbia	17.2	5.6	22.8	158.9	14.1	173.0
Northwest Alberta	17.7	9.5	27.2	149.6	14.6	164.2
Northern Plains	104.1	28.2	132.3	598.5	36.1	634.6
Southern Plains	31.8	8.4	40.2	78.6	1.0	79.6
Southeast Saskatchewan	-	-	-	72.7	2.0	74.7
Non-core regions	0.6	-	0.6	2.7	-	2.7
NORTH SEA UK SECTOR	-	-	-	7.4	-	7.4
OFFSHORE WEST AFRICA						
Cote d'Ivoire	-	-	-	4.1	-	4.1
TOTAL	171.4	51.7	223.1	1,072.5	67.8	1,140.3

<CAPTION>
2005

	Net exploratory			Net development		
	Productive	Dry holes	Total	Productive	Dry holes	Total
<S>	<C>	<C>	<C>	<C>	<C>	<C>
CANADA						
Northeast British Columbia	32.1	7.2	39.3	179.9	21.1	201.0
Northwest Alberta	29.9	9.0	38.9	135.2	7.3	142.5
Northern Plains	63.5	11.5	75.0	671.4	51.9	723.3
Southern Plains	50.6	5.0	55.6	294.9	2.0	296.9
Southeast Saskatchewan	1.0	-	1.0	43.0	-	43.0
Non-core regions	-	-	-	0.3	-	0.3
NORTH SEA UK SECTOR	-	0.8	0.8	11.5	0.9	12.4
OFFSHORE WEST AFRICA						
Cote d'Ivoire	-	0.6	0.6	3.5	-	3.5
TOTAL	177.1	34.1	211.2	1,339.7	83.2	1,422.9

</TABLE>

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, 2007:

<TABLE>
<CAPTION>

	Natural gas wells		Crude oil wells		Total wells	
	Gross	Net	Gross	Net	Gross	Net
<S>	<C>	<C>	<C>	<C>	<C>	<C>
CANADA						
Northeast British Columbia	1,541.0	1,294.1	232.0	194.5	1,773.0	1,488.6
Northwest Alberta	2,125.0	1,636.7	561.0	315.5	2,686.0	1,952.2
Northern Plains	3,908.0	3,081.6	6,277.0	5,379.8	10,185.0	8,461.4
Southern Plains	7,320.0	6,136.6	1,154.0	1,025.7	8,474.0	7,162.3
Southeast Saskatchewan	5.0	2.8	1,518.0	952.9	1,523.0	955.6
Non-core regions	122.0	34.9	70.0	21.7	192.0	56.6
UNITED STATES	5.0	0.6	3.0	0.5	8.0	1.1
NORTH SEA UK SECTOR	2.0	0.1	108.0	91.3	110.0	91.4
OFFSHORE WEST AFRICA						
Cote d'Ivoire	-	-	21.0	12.3	21.0	12.3
Total	15,028.0	12,187.4	9,944.0	7,994.2	24,972.0	20,181.5

</TABLE>

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

NORTHEAST BRITISH COLUMBIA

[GRAPHIC OMITTED]

Significant geological variation extends throughout the productive reservoirs in this region, producing light crude oil, NGLs and natural gas. The Company holds working interests ranging up to 100% and averaging 73% in 4,711,958 gross (3,430,948 net) acres of producing and undeveloped land in the region.

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 Company's asset base in Northeast British Columbia with the addition of the ACC properties in Adsett, Caribou and Fort St. John West. The southern portion of this region encompasses the Company's BC Foothills assets; here natural gas is produced from the deep Mississippian and Triassic aged reservoirs in this highly deformed structural area. In 2006 the Company's assets in Monkman and Ojay were augmented by the assets previously owned by ACC in the area.

Natural gas production from the region averaged 430 mmcf/d in 2007 compared to the average of 408 mmcf/d in 2006. Crude oil and NGLs production was steady at 7,000 bbl/d in 2007, from an average of 6,700 bbl/d in 2006.

During 2005, the Company initiated a new exploration and development play that targets natural gas found in the shallow Notikewin formation in the Fort St. John area. Wells drilled into this formation generally produce at rates of up to 500 to 700 mmcf/d. In combination with the Company's extensive land base and reduced royalty rates in British Columbia, this shallow gas drilling program will add to the Company's opportunities in this region. Development of this play continued in 2006 with the drilling of 45 wells at Ladyfern. Another shallow gas play was pursued in 2006 with the drilling of 50 Banff wells at Shekelie.

During 2007, the Company drilled 2.9 (2006 - 12.9) net crude oil wells, 42.1 (2006 - 163.2) net natural gas wells, 0.0 (2006 - 0.0) net stratigraphic/service wells and 16.1 (2006 - 19.7) net dry wells on its lands in this region for a total of 61.1 (2006 - 195.8) net wells. The Company held an average 81% working interest in these wells.

NORTHWEST ALBERTA

[GRAPHIC OMITTED]

The Company holds working interests ranging up to 100% and averaging 73% in 3,193,607 gross (2,338,858 net) acres of producing and undeveloped land in the region 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 RAX; 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 will 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. Recent regulatory changes have improved the economics of multi-zone production by providing the opportunity to commingle multiple zones within a single wellbore. The south western portion of this region also contains significant Foothills assets with natural gas produced from the deep Mississippian and Triassic aged reservoirs.

Natural gas production from the region averaged 596 mmcf/d in 2007 compared to an average of 454 mmcf/d in 2006. Crude oil and NGLs production increased to 17,000 bbl/d in 2007 from 15,000 bbl/d in 2006.

During 2007, the Company drilled 13.0 (2006 - 14.5) net crude oil wells, 98.5 (2006 - 152.8) net natural gas wells, 1.5 (2006 - 0.0) net stratigraphic/service wells, and 12.8 (2006 - 24.1) net dry wells on its lands in this region for a total of 125.8 (2006 - 191.4) net wells. The Company held an average 74% working interest in these wells.

NORTHERN PLAINS

[GRAPHIC OMITTED]

The Company holds working interests ranging up to 100% and averaging 85% in 12,098,317 gross (10,318,670 net) acres of producing and undeveloped land in the region located just south of Edmonton north to Fort McMurray and from the Northwest Alberta area east to the border with Saskatchewan and 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, with natural gas production from the region amounting to 418 mmcf/d in 2007 compared to 437 mmcf/d in 2006. Crude oil and NGLs production from this region increased to 201,400 bbl/d in 2007 up from 194,500 bbl/d in 2006. Production of natural gas was negatively impacted by the shut-in effective July 1, 2004 of approximately 11 mmcf/d in the Athabasca Wabiskaw-McMurray oil sands area pursuant to the decision of the Alberta Energy and Utilities Board. In 2007 the Company made a strategic decision to reduce natural gas drilling in Western Canada as a result of low natural pas prices and increase drilling in crude oil areas such as the Northern Plains area.

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. During 2006, natural gas development drilling included 120.5 net wells and 48.0 net Horseshoe Canyon CBM locations. Evaluation of the potential for production of CBM from the Mannville coals commenced in 2006 with the drilling of three horizontal wells; these wells will be tested in 2008 to determine the economic viability of this play.

In the area near Lloydminster, Alberta, reserves of heavy crude oil (averaging 12(0)-14(0) 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 both the result of Crown land purchases and several acquisitions including major acquisitions from Sceptre Resources, Koch Exploration, Ranger Oil and Petrovera. As part of the acquisition of Ranger, the Company also acquired a 50% interest in the ECHO Pipeline system, a crude oil transportation pipeline; and, in 2001 the Company acquired the remaining 50%. The pipeline was extended north to the Company operated Beartrap Field during 2001 and to the Morgan Field in 2006 enhancing development and reducing operating costs for the Company's extensive holdings in the area. This pipeline was capable of transporting 57,000 bbl/d of hot, unblended crude oil to sales facilities at Hardisty, Alberta and in 2003 its capacity was expanded to handle up to 72,000 bbl/d. The ECHO Pipeline system is a high temperature, insulated pipeline that eliminates the requirement for field condensate blending. The pipeline 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.

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(0)-11(0) API) crude oil. The two processes employed by the Company are cyclic steam stimulation 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 80,000 bbl/d of crude oil which expanded to 119,500 bbl/d in 2007. 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. Canadian Natural drilled 58 high-pressure wells in 2004. In 2004, the Company started to proceed with its Primrose North expansion project, which was effectively completed in late 2005 with total capital expenditures of approximately $300 million incurred. The Primrose North expansion entails a remote steam generation facility and additional high pressure cyclic steam wells. First crude oil production from the expansion project began in January 2006. Also in 2004 the Company filed a public disclosure document for regulatory approval of 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 development application for Primrose East was submitted to the Alberta Energy and Utilities Board in January 2006, with potential impacts associated with the use of bitumen as fuel being evaluated in the Environmental Impact Assessment. The Company received regulatory approval for the project in February, 2007 and construction began in 2007, with the first oil production targeted to commence in 2009. 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. In December 2006 Canadian Natural issued a Public Disclosure Document outlining the proposed development plan for the Kirby In-Situ Oil Sands Project located approximately 85 km northeast of Lac La Biche. The Regulatory application for Kirby was submitted in September 2007 outlining the Company's plan to build a 45,000 bbl/d in-situ oil sands project.

In 2006 the Company undertook a Scoping Study to evaluate the construction of an upgrader to process the Company's Athabasca and Cold Lake thermal production. The study included evaluating the product alternatives, location, technology, gasification and integration with existing assets. The next steps in this process would include a Design Base Memorandum ("DBM") and Engineering Design Specifications ("EDS") which would be required to be completed prior to construction and sanctioning of the project by the Board of Directors of the Company. Based upon the results of the Scoping Study, which identified growing concerns relating to increased environmental costs for upgraders located in Canada, inflationary capital cost pressures and narrowing heavy oil differentials in North America, the Company has, at this point in time, deferred the DBM and EDS pending clarification on the cost of future environmental legislation and a more stable cost environment.

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(0)-17(0) 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. The Company holds and controls approximately 75% of the known crude oil pool in this area.

It is estimated this field 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 existing primary production on the Company's developed leases. Hence, in 2002 the Company embarked upon an Enhanced Oil Recovery ("EOR") scheme using an emulsion flood to increase the ultimate recoveries from the field. The experimental Pelican Lake emulsion flood showed that the recovery mechanism was very efficient; however, response time was slow. Due to the slow response time, the Company reverted to a waterflood scheme for this field. The waterflood provided initial production increases as expected and has shown positive waterflood response. To date approximately 11% of the field has been converted to waterflood. To further enhance the expected crude oil recovery from the waterflood, in the second quarter of 2005, the Company initiated a five well polymer flood pilot test.

Performance of the polymer flood pilot test has been positive, with crude oil production rates from the three production wells increasing from approximately 60 bbl/d in 2005 to over 500 bbl/d by December 2006. The commercial expansion of this EOR technology continues with 70 polymer injection wells at year end 2007. Pelican Lake production averaged approximately 34,000 bbl/d in 2007.

During 2007, the Company drilled 524.4 (2006 - 484.0) net crude oil wells, 95.6 (2006 - 218.6) net natural gas wells, 145.8 (2006 - 206.9) net stratigraphic/service wells, and 61.8 (2006 - 64.3) net dry wells for a total of 827.6 (2006 - 973.8) net wells. The Company's average working interest in these wells was 92%.

SOUTHERN PLAINS AND SOUTHEAST SASKATCHEWAN

[GRAPHIC OMITTED]

In the Southern Plains area, the Company holds interests ranging up to 100% and averaging 82% in 2,917,066 gross (2,379,552 net) acres of producing and undeveloped land in the region, 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 have been augmented in 2006 as a result of the Company's development of the Senate shallow gas play in SW Saskatchewan and the purchase of the ACC Hatton assets in SW Saskatchewan. Other assets acquired from ACC in this region include the crude oil producing assets at Taber.

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 Company's share of production in the Southern Plains area averaged 12,700 bbl/d of crude oil and NGLs in 2007 compared to 10,500 bbl/d in 2006. Natural gas production amounted to 196 mmcf/d in 2007 compared to the 165 mmcf/d averaged in 2006.

During 2007, the Company drilled a total of 19.1 (2006 - 6.2) net crude oil wells, 147.5 (2006 - 104.2) net natural gas wells, 1.0 (2006 - 0.0) net stratigraphic/service wells and 1.6 (2006 - 9.4) net dry wells in this region for a total of 169.2 (2006 - 119.8) net wells. The Company's average working interest in these wells was 79%.

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. The Company holds interests ranging up to 100% and averaging 82% in 220,266 gross (181,691 net) acres of producing and undeveloped lands in the region.

The region produces primarily light sour crude oil from as many as seven productive horizons found at depths up to 2,700 meters. The Company's share of production in the Southeast Saskatchewan area averaged 8,400 bbl/d of crude oil and NGLs in 2007 compared to 8,400 bbl/d in 2006. Natural gas production averaged 2 mmcf/d in 2007 (2006 - 3 mmcf/d).

The Company drilled 24.0 (2006 - 72.7) net crude oil wells, 0.0 (2006 - 0.0) net natural gas well, 4.0 (2006 - 0.0) net stratigraphic/service wells and 0.4 (2006 - - 2.0) net dry wells in this region in 2007, for a total of 28.4 (2006 - 74.7) net wells. The Company's average working interest in these wells is 84%.

HORIZON OIL SANDS PROJECT

[GRAPHIC OMITTED]

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. The project includes surface oil sands mining, bitumen extraction, bitumen upgrading to produce a 34 o API SCO, and associated infrastructure.

Canadian Natural filed an application for regulatory approval of the Horizon Project in June 2002. 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 that the Horizon Project is 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.

The Project, which has two aspects, bitumen production and bitumen upgrading to SCO, is designed as a phased development. Site clearing and pre-construction preparation activities commenced in 2004 and construction is planned to continue through 2013. Phase 1 production is targeted to begin in the third quarter of 2008 ramping up to 110,000 bbl/d of SCO. Subsequent expansion through Phases 2/3, which is further broken down into a series of four Tranches, is expected to increase production to 232,000 bbl/d of SCO out to 2013. These targeted rates of production represent nominal design capacity. Construction of some components and portions of facilities for the future expansions have already been completed and certain major long lead equipment for Phases 2/3 was ordered in 2006 with deliveries to site expected in 2008. Canadian Natural will seek to maximize resource recovery and overall production through ongoing optimization of operations.

Canadian Natural used a structured system called Front End Loading to ensure that project definition is adequate and complete before proceeding with implementation. This system is used successfully worldwide to mitigate risk on large capital projects in a variety of industries. The process is well documented at every step and is audited by an independent organization. In June 2002, the Company commenced the Design Basis Memorandum ("DBM"), which is the second of three front-end engineering phases. The DBM was completed for all project components in February 2004. In August 2003, the Company commenced work on the third and final front-end engineering phase for Phase 1, completing the work in December 2004. The products of this phase include a detailed project execution plan, Engineering Design Specifications ("EDS") and a detailed cost estimate (plus or minus 10%). The EDS provided sufficient definition for a lump sum inquiry for the Detailed Engineering, Procurement and Construction of the various project components. With this information a "cost certainty" estimate was developed as a basis for project sanction by the Board of Directors, which was given in February 2005, authorizing management to proceed with Phase 1 of the Horizon Project. The Company is now developing various cost effective options for execution of additional construction on Phases 2/3.

The Horizon Project is designed to use proven technology and will seek to take advantage of technology improvements that advance environmental performance, enhance the work environment for workers, increase reliability and production and reduce capital and production costs. By the end of 2004 the Company had acquired all key technologies for the project. At year end 2007, Canadian Natural's Horizon Project team, consisted of 925 permanent employees which consisted of 661 project staff personnel and 264 operations personnel to fill 63% of the projected project and operations team position requirements.

Horizon Project Phase 1 construction costs were approximately $2.74 billion in 2007 and cumulative expenditures were approximately $6.76 billion through the end of 2007. Phase 1 construction capital is budgeted to be approximately $1.7 billion to $1.9 billion in 2008, representing a cost to completion forecast range of 25% to 28% over the original $6.8 billion estimate. In addition, capital expenditures of $439 million are budgeted for Tranche 2 development and construction in 2008. These expenditures are direct project costs only and do not include capitalized interest, stock based compensation or lease evaluation.

During 2007, the Company drilled 98.0 (2006 - 163.0) stratigraphic test wells to further delineate the ore body and confirm resource quality and quantity.

UNITED KINGDOM NORTH SEA

[GRAPHIC OMITTED]

The Company's wholly owned subsidiary CNR International (U.K.) Limited, formerly Ranger Oil (U.K.) Limited, has operated in the North Sea for 30 years and has developed a significant database, extensive operating experience and an experienced staff. The Company owns interests ranging from 7% up to 100% in 478,061 gross (374,720 net) acres of producing and non-producing properties in the UK sector of the North Sea. In 2007, the Company produced from 16 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%. In 2002, the Company completed property acquisitions in the northern North Sea that increased its ownership levels in the Ninian, Murchison, Lyell and Columba Terraces Fields. As part of the transaction the Company also acquired an interest in the Strathspey Field and 12 licences covering 20 exploration blocks and part blocks surrounding the Ninian and Murchison platforms. Increased ownership in the Brent and Ninian pipelines and the Sullom Voe Terminal was also acquired. In 2003, the Company further consolidated its ownership with the acquisition of additional working interests in the Ninian and Columba Fields, associated facilities and adjacent exploration acreage. In 2007 the Company acquired a 58.7% working interest in the abandoned Hutton Field, increasing its working interest in this currently non-producing Field to 66.5%.

In the central portion of the North Sea, in 2003, the Company increased its equity in the Banff Field to 87.6% and took over as operator. The Company also owns a 45.7% operated working interest in the Kyle Field. Beginning in the third quarter of 2005, all production for the Kyle Field was processed through the Banff FPSO facilities. The consolidation of these production facilities resulted in lower combined production costs from these fields.

In 2004, the Company acquired 100% working interest in T-block (comprising the Tiffany, Toni and Thelma Fields) and 68.7% to 75.3% interests in the Fields known as B-block (comprising Balmoral, Stirling and Glamis). The Company took over as operator of these fields. In 2007 the Company disposed of its interests in the B Block 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 2007, production to the Company from this region averaged approximately 55,900 bbl/d of crude oil (2006 - 60,100 bbl/d). Natural gas production averaged 13.0 mmcf/d in 2007 (2006 - 15.0 mmcf/d).

During 2007 the Company drilled 3.7 (2006 - 7.4) net crude oil wells, 3.5 (2006 - - 1.8) net stratigraphic/service wells and 0.0 (2006 - 0.0) net dry wells in this region for a total of 7.2 (2006 - 9.2) net wells. The Company's average working interest in these wells is 90%.

OFFSHORE WEST AFRICA

[GRAPHIC OMITTED]

With the purchase of Ranger in 2000, the Company acquired interests in areas of crude oil and natural gas exploration and development offshore Cote d'Ivoire and Angola, West Africa. During 2005, the Company either relinquished or sold all of its interests in offshore Angola. In 2006, certain exploration acreage in Cote d'Ivoire was also relinquished.

In 2005, the Company acquired the permit to develop the Olowi Field, offshore Gabon, West Africa, consisting of 151,818 acres. The Company has a 90% interest in a production sharing agreement for the block.

The Company also has a 100% interest in 4,001,574 acres offshore South Africa where it is shooting and evaluating seismic data and undertaking environmental studies.

COTE D'IVOIRE

The Company owns interests in two exploration licences offshore Cote d'Ivoire comprising 55,408 net acres. During 2001, the Company increased its interest in Block CI-26, which contains the Espoir Field, to a 58.7% operating interest. The Espoir Field is located in water depths ranging from 100 to 700 meters. During the 1980s, the Espoir Field produced approximately 31 million barrels of crude oil by natural depletion prior to relinquishment by the previous licencees in 1988. The government of Cote d'Ivoire approved a development plan to recover the remaining reserves and the Company will continue its exploitation and development of the field. The first phase of development of East Espoir, which included the drilling of both producing and water injection wells from a single wellhead tower, was completed in 2003. The construction and installation of a new wellhead tower for the West Espoir part of the field were completed in 2005. Due to a successful infill drilling program completed at East Espoir in early 2006 the Company achieved approximately 24,000 bbl/d of net production from the Field. Following the infill drilling at East Espoir, development drilling commenced at West Espoir with first oil from the Field delivered July, 2006. Development drilling at West Espoir continued throughout 2007 and was completed in early 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. In 2003, the Company drilled a satellite pool, Acajou, which encountered a reservoir with good quality hydrocarbons. The extent of this accumulation was further appraised by a well drilled in 2004 which did not encounter commercial hydrocarbons.

The unsuccessful Zaizou exploration well was drilled in block CI-40 in 2005.

In the first quarter of 2001, the Company drilled and tested the Baobab exploration prospect, identified on Block CI-40, eight kilometers south of the Espoir facilities, in which the Company has a 58% interest. The well encountered hydrocarbons at a rate of 6,700 bbl/d of crude oil. A second test well in 2002 also produced hydrocarbons at a rate in excess of 10,000 bbl/d of crude oil. The Company established a field development plan, which was approved by the Government of Cote d'Ivoire in December 2002. In 2003, the Company awarded four major contracts for the development of the Baobab Field. These contracts included the deep water drilling rig to drill 8 producing and 3 water injection wells, the FPSO, supplies for the subsea equipment and the supply of pipeline and risers, and installation of the subsea infrastructure. Development commenced in late 2003 and first oil was achieved in August 2005 producing at approximately 30,000 bbl/d net to Canadian Natural from 4 wells. Upon completion of drilling additional wells in 2006, production levels increased as expected. Subsequent problems with the control of sand and solids production led to five of the ten production wells being shut in by the end of the year, resulting in approximately 15,500 bbl/d of net production capacity being shut in. The Company has secured a deepwater rig, expected in mid-year 2008, that is expected to enable the Company to execute its plan to return certain of the shut-in wells to production over the course of 2008 and 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.

During 2007, Company production averaged approximately 28,500 bbl/d of crude oil (2006- 36,700 bbl/d). Company natural gas production amounted to 12.1 mmcf/d in 2007 (2006 - 9.5 mmcf/d).

In 2007, the Company drilled 4.1 (2006 - 4.1) net crude oil wells, 0.6 (2006 - 1.7) net stratigraphic/service wells and 0.0 (2006 - 0.0) net dry wells for a total of 4.7 (2006 - 5.8) net wells. The Company's average working interest in these wells is 59%.

GABON

[GRAPHIC OMITTED]

In late 2005, the Company acquired permit No. G4-187 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. Olowi has been delineated by the drilling of 15 wells on the block. A development plan, comprising an FPSO and four drilling towers, was filed with the Gabonese Government in late 2005 and approved in February 2006. The development will target the western flank of the structure where the oil is located as a rim below a large gas cap. Major contracts covering the FPSO, platforms, flowlines and the drilling rig were awarded in late 2006. Construction is underway and first oil is targeted for late 2008. It is planned that in total 28 horizontal production wells plus one gas injector well will be drilled. Crude oil production will rely on gas cap expansion supplemented by re-injection of the produced solution gas. Production is expected to ramp up during 2009 to a plateau rate of approximately 20,000 bbl/d net to the Company.

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

For the year ended December 31, 2007, the Company retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule") and Ryder Scott Company ("Ryder Scott") 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 includes all of the Company's light/medium, primary heavy, and thermal crude oil, natural gas, coal bed methane and NGLs activities. It does not include the Company's oil sands mining assets. Conventional crude oil, NGLs, and natural gas reserves, net of royalties, are estimated using royalty regulations in effect as of December 31, 2007. Similarly, bitumen and synthetic crude oil reserves, net of royalties, relating to surface mineable oil sand projects are estimated using royalty regulations in effect as of December 31, 2007. Royalty changes proposed by the Government of Alberta will be incorporated in the reserves evaluation should they be enacted. Sproule evaluated the Company's North America conventional assets and Ryder Scott evaluated the international conventional assets. The Company has been granted an exemption from 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 reserve reconciliation 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. 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 voluntary additional 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. Only 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 voluntary additional 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 each of Sproule and Ryder Scott 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.

The following tables summarize the evaluations of conventional reserves and estimated net present values of these reserves at December 31, 2007.

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 SUBSTANTIAL.

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

<TABLE>
<CAPTION>
Constant Prices and Costs

Crude oil & NGLs (mmbbl)		Natural gas (bcf)	
Total proved reserves	Total proved & probable reserves	Total proved reserves	Total proved & probable reserves
<S>	<C>	<C>	<C>	<C>
NORTH AMERICA				
Canada	920	1,545	3,519	4,600
United States	--	--	2	2
INTERNATIONAL				
United Kingdom	310	405	81	113
Cote d'Ivoire	110	166	64	88
Gabon	18	20	--	--
TOTAL	1,358	2,136	3,666	4,803

</TABLE>

CONVENTIONAL CRUDE OIL, NGLS AND NATURAL GAS RESERVES

<TABLE>
<CAPTION>
Constant Prices and Costs

Crude oil & NGLs (mmbbl)		Natural gas (bcf)	
Company gross	Net	Company gross	Net
<S>	<C>	<C>	<C>	<C>
Proved developed reserves	828	736	3,454	2,842
Proved undeveloped reserves	715	622	981	824
TOTAL PROVED RESERVES	1,543	1,358	4,435	3,666
TOTAL PROVED & PROBABLE RESERVES	2,430	2,136	5,804	4,803

</TABLE>

ESTIMATED NET PRESENT VALUE

<TABLE>
<CAPTION>
Constant Prices and Costs

Undiscounted	Discounted at:		
($ millions)	10%	15%	20%
<S>	<C>	<C>	<C>	<C>
Proved developed reserves	$ 42,653	$ 25,767	$ 21,924	$ 19,229
Proved undeveloped reserves	$ 22,986	$ 8,810	$ 6,082	$ 4,340
TOTAL PROVED RESERVES	$ 65,639	$ 34,577	$ 28,006	$ 23,569
TOTAL PROVED & PROBABLE RESERVES	$ 94,316	$ 44,286	$ 34,604	$ 28,331

</TABLE>

CONVENTIONAL CRUDE OIL, NGLS AND NATURAL GAS RESERVES

<TABLE>
<CAPTION>
Forecast Prices and Costs

Crude oil & NGLs (mmbbl)		Natural gas (bcf)	
Company gross	Net	Company gross	Net
<S>	<C>	<C>	<C>	<C>
Proved developed reserves	814	730	3,464	2,850
Proved undeveloped reserves	721	626	982	822
TOTAL PROVED RESERVES	1,535	1,356	4,446	3,672
TOTAL PROVED & PROBABLE RESERVES	2,426	2,129	5,817	4,810

</TABLE>

ESTIMATED NET PRESENT VALUES

<TABLE>
<CAPTION>
Forecast Prices and Costs

Undiscounted	Discounted at:		
($ millions)	10%	15%	20%
<S>	<C>	<C>	<C>	<C>
Proved developed reserves	$ 39,393	$ 25,013	$ 21,501	$ 18,984
Proved undeveloped reserves	$ 26,455	$ 9,494	$ 6,478	$ 4,594
TOTAL PROVED RESERVES	$ 65,848	$ 34,507	$ 27,979	$ 23,578
TOTAL PROVED & PROBABLE RESERVES	$ 104,860	$ 46,364	$ 35,860	$ 29,208

</TABLE>

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 2007 adjusted for quality and transportation as well as the 2007 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$1.01/C$1.00):

Natural gas

Company average price (Year)	Henry Hub Louisiana (C$/mcf)	AECO (US$/mmbtu)	Huntingdon/ Sumas (C$/mmbtu)	(C$/mmbtu)
2007	6.48	6.80	6.52	6.96

Crude oil & NGLs

Company average price (Year)	WTI @ Cushing(1) (C$/bbl)	Hardisty Heavy 12(0) API (US$/bbl)	Edmonton Par(2) (C$/bbl)	North Sea Brent (C$/bbl)	(US$/bbl)
2007	62.87	96.00	41.70	93.44	96.02

(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(0) 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. Reference prices and costs are escalated at 2% per year. Future crude oil, NGLs and natural gas price forecasts were based on Sproule's December 31, 2007 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 2007 evaluation were $62.87 per barrel and $6.48 per mcf respectively. The crude oil and natural gas forecast prices used in the Evaluation Reports are as follows:

Natural gas

Company average price (Year)	Henry Hub Louisiana (C$/mcf)	AECO (US$/mmbtu)	Huntingdon/ Sumas (C$/mmbtu)	(C$/mmbtu)
2008	6.37	7.56	6.51	6.51
2009	7.07	8.27	7.22	7.22
2010	7.50	8.74	7.69	7.69
2011	7.49	8.75	7.70	7.70
2012	7.41	8.66	7.61	7.61
2013	7.45	8.83	7.78	7.78
2014	7.65	9.01	7.96	7.96
2015	7.84	9.19	8.14	8.14
2016	8.04	9.37	8.32	8.32
2017	8.25	9.56	8.51	8.51
2018	8.44	9.75	8.68	8.68

Crude oil & NGLs

Company average price (Year)	WTI @ Cushing(1) (C$/bbl)	Hardisty Heavy 12(0) API (US$/bbl)	Edmonton Par(2) (C$/bbl)	North Sea Brent (C$/bbl)	(US$/bbl)
2008	65.51	89.61	54.67	88.17	87.61
2009	63.58	86.01	52.42	84.54	83.97
2010	61.86	84.65	51.56	83.16	82.57
2011	60.76	82.77	50.38	81.26	80.65
2012	60.90	82.26	50.05	80.73	80.10
2013	63.20	82.81	50.38	81.25	80.60
2014	63.53	84.46	51.39	82.88	82.21
2015	63.96	86.15	52.42	84.55	83.85
2016	65.04	87.87	53.47	86.25	85.53
2017	66.86	89.63	54.55	87.98	87.24
2018	67.43	91.42	55.64	89.74	88.99

Note: Foreign exchange rate used was US$1.00/C$1.00 throughout the forecast

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:

($ millions)	Proved Forecast price case	Proved Constant price case	Proved & probable Forecast price case	Proved & probable Constant price case
2008	1,642	1,632	1,851	1,841
2009	2,200	2,095	2,520	2,418
2010	1,092	1,023	1,482	1,408
2011	803	733	1,398	1,293
2012	945	836	1,540	1,388
2013	594	508	1,086	961
2014	338	286	653	570
2015	332	275	768	655
2016	339	253	587	472
2017	218	178	436	361
2018	201	160	350	285
2019	272	210	485	387
Thereafter	1,927	1,274	3,324	2,225

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 and Ryder Scott to be reasonable and no field inspection was conducted.

A report on conventional reserves data by Sproule and Ryder Scott 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 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 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:

<TABLE>
<CAPTION>

Crude oil & NGLs (mmbbl)				Natural gas (bcf)			
Offshore				Offshore			
North America	North Sea	West Africa	Total	North America	North Sea	West Africa	Total
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
PROVED RESERVES								
RESERVES, DEC 31, 2005	694	290	134	1,118	2,741	29	72	2,842
Extensions & discoveries	53	3	--	56	250	--	--	250
Infill drilling	190	14	--	204	71	--	--	71
Improved recovery	--	12	--	12	3	--	--	3
Property purchases	26	--	--	26	1,111	--	--	1,111
Property disposals	--	--	--	--	(1)	--	--	(1)
Production	(75)	(22)	(13)	(110)	(433)	(5)	(3)	(441)
Revisions of prior estimates	(1)	2	9	10	(37)	13	(13)	(37)
RESERVES, DEC 31, 2006	887	299	130	1,316	3,705	37	56	3,798
Extensions & discoveries	30	--	--	30	134	--	--	134
Infill drilling	10	6	--	16	124	3	--	127
Improved recovery	3	--	--	3	8	--	--	8
Property purchases	1	--	--	1	12	--	--	12
Property disposals	--	(3)	--	(3)	--	--	--	--
Production	(77)	(20)	(10)	(107)	(503)	(5)	(4)	(512)
Revisions of prior estimates	66	28	8	102	41	46	12	99
RESERVES, DEC 31, 2007	920	310	128	1,358	3,521	81	64	3,666
PROVED AND PROBABLE RESERVES								
RESERVES, DEC 31, 2005	1,035	417	206	1,658	3,548	69	110	3,727
Extensions & discoveries	128	3	--	131	307	--	--	307
Infill drilling	384	17	--	401	95	--	--	95
Improved recovery	--	12	--	12	4	--	--	4
Property purchases	34	--	--	34	1,466	--	--	1,466
Property disposals	--	--	--	--	(1)	--	--	(1)
Production	(75)	(22)	(13)	(110)	(433)	(5)	(3)	(441)
Revisions of prior estimates	(4)	(5)	2	(7)	(129)	29	(8)	(108)
RESERVES, DEC 31, 2006	1,502	422	195	2,119	4,857	93	99	5,049
Extensions & discoveries	41	--	--	41	177	--	--	177
Infill drilling	52	6	--	58	163	3	--	166
Improved recovery	4	--	--	4	8	--	--	8
Property purchases	2	6	--	8	17	1	--	18
Property disposals	--	(3)	--	(3)	(1)	--	--	(1)
Production	(77)	(20)	(10)	(107)	(503)	(5)	(4)	(512)
Revisions of prior estimates	21	(6)	1	16	(116)	21	(7)	(102)
RESERVES, DEC 31, 2007	1,545	405	186	2,136	4,602	113	88	4,803

</TABLE>

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 2007 Annual Report under "Supplementary Oil and Gas Information" on pages 97 to 101 and is incorporated herein by reference.

D. OIL SANDS MINING DISCLOSURE

INTRODUCTION

Canadian Natural holds 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 was initiated in 2000 to evaluate the potential for mining and processing the oil sands on these leases.

The Horizon Project is located in northeastern Alberta approximately 70 kilometers north of Fort McMurray in Townships 96 and 97, Ranges 11, 12 and 13, west of the 4th Meridian. The project site is accessible by a private road as well as a private airstrip. Figure 1 shows the location of the Horizon Project within Alberta, Canada and within the region. The leases being developed for the Horizon Project are 18, 25, 10, 19 and 20. Synthetic crude oil production is targeted for the third quarter of 2008 ramping up to 110,000 bbl/d and is targeted to reach 232,000 bbl/d with future expansion. Mining of the oil sands will be done using conventional truck and shovel technology. The ore is then processed through extraction and froth treatment to produce bitumen, which is upgraded on-site into synthetic crude oil. The synthetic crude oil is transported from the site by pipeline to the Edmonton area for distribution. An on-site cogeneration plant provides power and steam for the operation.

An independent qualified reserves evaluator, GLJ, was retained to evaluate 100% of the first three phases of the Horizon Project's development plan. GLJ's Evaluation Report indicates that the gross lease proved and probable reserves associated with the Horizon Project are approximately 3.0 billion barrels of synthetic crude oil with a production life of 39 years.

Since 1999, Canadian Natural has acquired over 46,000 hectares, comprising 11 leases in the Fort McMurray area.

FIGURE 1 - LOCATION OF THE 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.

Lease 18, the main oil sand 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.

PROJECT DEVELOPMENT

On June 28, 2002, pursuant to Sections 10 and 11 of the Oil Sands Conservation Act, Canadian Natural filed Application No. 1273113 for approval for an oil sands mine, a bitumen extraction plant, a bitumen upgrader and associated facilities for the proposed Horizon Project. As part of the application to the Alberta Energy and Utilities Board ("EUB"), the Company also submitted an Environmental Impact Assessment ("EIA") report to the Director of the Regulatory Assurance Division, Alberta Environment, pursuant to the Environmental Protection Enhancement Act ("EPEA"). On June 26, 2003, the Federal Minister of Fisheries and Oceans referred the EIA of the project to a review panel charged with fulfilling the review as required by both the Canadian Environmental Assessment Act ("CEAA") and the Energy Resources Conservation Act ("ERCA"). A public hearing was held in Fort McMurray, Alberta on September 15-19, 22-26 and 29, 2003. The application and hearing provided significant background detail on the geology, mine planning and development scheme and formed the basis for the approval from the EUB in February 2004 and Alberta Environment ("AENV") under the Environmental Protection and Enhancement Act, in April 2004.

The following are the primary regulatory applications and approvals for the Horizon Project, which contain information pertaining to the project of a material engineering, geologic or metallurgic nature:

1. Application for Approval of Horizon Oil Sands Project submitted in June 2002 to the EUB (Application No.1273113) and AENV (Application No. 001-149968) (available at the EUB library, 640 5th Ave. SW, Calgary, Alberta - Tel: (403) 297-8311).

2. Supplemental Information for the Horizon Oil Sands Project (Application No. 1273113 and Application No. 001-149968) submitted in March 2003 to the EUB and AENV) (available at the EUB library, 640 5th Ave. SW, Calgary, Alberta - Tel: (403) 297-8311).

3. Horizon Oil Sands Project Decision 2004-005 by a joint panel review established by the EUB and the Government of Canada dated January 27, 2004 (available online at www.eub.gov.ab.ca).

4. Horizon Oil Sands Project Order in Council Authorization 26/2004 by the Province of Alberta dated February 4, 2004 (available at the EUB library, 640 5th Ave. SW, Calgary, Alberta - Tel: (403) 297-8311).

5. Horizon Oil Sands Project Approval No. 9752 by the EUB dated February 10, 2004 (available at the EUB library, 640 5th Ave. SW, Calgary, Alberta - Tel: (403) 297-8311).

6. Horizon Oil Sands Project Environmental Protection and Enhancement Act Approval No. 149968-00-01 from AENV dated April 6, 2004 (available online at WWW.GOV.AB.CA/ENV/WATER/APPROVALVIEWER.HTML search parameter - Approval No. 149968-00-01).

7. Horizon Oil Sands Project Water Act Approval No. 00201931-00-00 from AENV dated April 6, 2004 (available online at WWW.GOV.AB.CA/ENV/WATER/APPROVALVIEWER.HTML search parameter - Approval No. 149968-00-01).

As of year-end 2007, key development achievements associated with the Horizon Project were as follows:

|X| Phase 1 work progress is 90% complete.

|X| Mine overburden has removed 49.9 million bank cubic meters of material.

REGIONAL AND PROJECT GEOLOGY

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 general stratigraphy of the Horizon Project is shown in Figure 2.

The McMurray Formation was formed by the infilling of a broad northwest trending depression in the exposed Devonian limestone landscape by mostly non-marine and estuarine sediments about 115 million years ago. The deposition of these terrestrial derived sediments ended when the Boreal Sea transgressed the entire region, ushering in marine conditions that formed the Clearwater Formation shales and glauconitic Wabiskaw member. This interplay between rising sea level and sediment transport from the northeast gave rise to various depositional environments (fluvial, estuarine, and marine). The entire McMurray/Clearwater succession was (most recently about 10,000 years ago) covered by unconsolidated sands, silts, and clays (glacial drift) deposited by glaciers as they melted and receded from the region at the end of the last ice age.

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 lower McMurray, where present, is comprised of predominantly fluvial channel deposits. The lower McMurray occupies lows on the Devonian (Paleozoic) surface resulting in the thickest McMurray intervals. Clean sands in these fluvial channels result in excellent quality ore. Flood plain deposits of significant thickness are found in the upper portions of the lower McMurray and are typically removed as waste. In the deepest portions of the mine area, the lower McMurray is comprised of "water sands". These sands are barren of bitumen; having never been saturated with bitumen or, in some places, originally containing bitumen that has since been removed from the sands through the movement of basal waters over time producing "swept" zones.

The middle McMurray is comprised of thick estuarine channel successions and tidal flat deposits resulting in interbedded sands and muds. The estuarine channel sands provide good quality ore. The muddier intervals within the channels and the tidal flat deposits within the middle McMurray represent zones of interburden in the mining area.

The upper McMurray consists of shoreface/channel transition deposits and is typically thin, less than five meters. Locally, this member may be entirely eroded. Exceptional thickness of about 15 meters can be found within the upper McMurray. In most cases, the bitumen saturation in the upper McMurray is poor and the material is included with the overburden.

FIGURE 2 - GENERAL STRATIGRAPHY OF THE HORIZON OIL SANDS PROJECT



HORIZON OIL SANDS PROJECT MINING RESERVES

For the year ended December 31, 2007, 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 pit limits and mine plans were evaluated in 2007 incorporating the results from the most recent and past drilling programs. 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 oil sands mining reserves from GLJ's Evaluation Report are provided in Table 2. The 3.0 billion barrels of gross lease proved and probable synthetic crude oil reserves shown in the table are produced from 39 years of projected production commencing in 2008.

The Reserve 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]

FIGURE 4 - HORIZON OIL SANDS PROJECT CORE HOLE COVERAGE

OIL SANDS MINING RESERVES

The following table sets out Canadian Natural's reserves of bitumen and synthetic crude oil from the Horizon Project as of December 31, 2007:

Constant Prices

	Bitumen (mmbbl)		Synthetic crude oil (1) (mmbbl)	
	Gross Lease (2)	Net	Gross Lease (2)	Net
Total proved reserves	2,385	1,995	1,956	1,761
Total Proved and probable reserves	3,525	2,969	2,958	2,680

(1) Synthetic crude oil reserves are based on the upgrading of bitumen using technologies implemented at the Horizon Project. the reserves shown for bitumen and synthetic crude oil are not additive.

(2) Gross Lease reserves are the total remaining recoverable reserves on the lease before consideration of Company interests or royalties.

E. 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	2007	2006	2005
Daily production, before royalties			
Crude oil and NGLs (bbl/d)	331,232	331,998	313,168
Natural gas (mmcf/d)	1,668	1,492	1,439
Annual production, before royalties			
Crude oil and NGLs (mbbl)	120,900	121,179	114,306
Natural gas (bcf)	609	545	525

NETBACKS

INFORMATION BY QUARTER

<TABLE>
<CAPTION>

2007

	Q1	Q2	Q3	Q4	YEAR ENDED
AVERAGE DAILY PRODUCTION VOLUMES, BEFORE ROYALTIES					
Crude oil and NGLs (bbl/d)	327,001	327,494	333,062	337,240	331,232
Natural gas (mmcf/d)	1,717	1,722	1,647	1,589	1,668
PRODUCT NETBACKS					
Crude oil and NGLs ($/bbl)					
Sales price (1)	$ 51.71	$ 53.74	$ 58.10	$ 58.03	$ 55.45
Royalties	4.92	5.46	6.65	6.66	5.94
Production expenses	13.81	15.01	13.13	11.53	13.34
NETBACK	$ 32.98	$ 33.27	$ 38.32	$ 39.84	$ 36.17
Natural gas ($/mcf)					
Sales price (1)	$ 7.74	$ 7.44	$ 5.87	$ 6.28	$ 6.85
Royalties	1.48	1.10	0.89	0.94	1.11
Production expenses	0.97	0.89	0.88	0.91	0.91
NETBACK	$ 5.29	$ 5.45	$ 4.10	$ 4.43	$ 4.83
CRUDE OIL AND NGLS NETBACKS BY TYPE					
Light/Pelican Lake/ NGLs ($/bbl)					
Sales price (1)	$ 60.19	$ 64.10	$ 67.34	$ 72.62	$ 65.99
Royalties	4.89	5.87	7.24	8.34	6.57
Production expenses	13.85	14.91	14.40	12.64	13.95
NETBACK	$ 41.45	$ 43.32	$ 45.70	$ 51.64	$ 45.47
Heavy crude oil ($/bbl)					
Sales price (1)	$ 41.24	$ 41.85	$ 48.10	$ 43.06	$ 43.66
Royalties	4.96	4.98	6.00	4.95	5.23
Production expenses	13.76	15.12	11.75	10.38	12.66
NETBACK	$ 22.52	$ 21.75	$ 30.35	$ 27.73	$ 25.77

<CAPTION>

2006

	Q1	Q2	Q3	Q4	YEAR ENDED
AVERAGE DAILY PRODUCTION VOLUMES, BEFORE ROYALTIES					
Crude oil and NGLs (bbl/d)	323,662	338,852	321,665	343,705	331,998
Natural gas (mmcf/d)	1,436	1,475	1,437	1,620	1,492
PRODUCT NETBACKS					
Crude oil and NGLs ($/bbl)					
Sales price (1)	$ 43.79	$ 60.05	$ 62.55	$ 47.27	$ 53.65
Royalties	3.48	5.14	5.11	4.10	4.48
Production expenses	11.33	11.92	13.47	12.32	12.29
NETBACK	$ 28.98	$ 42.99	$ 43.97	$ 30.85	$ 36.88
Natural gas ($/mcf)					
Sales price (1)	$ 8.30	$ 6.16	$ 5.83	$ 6.66	$ 6.72
Royalties	1.70	1.11	1.11	1.26	1.29
Production expenses	0.80	0.80	0.84	0.86	0.82

NETBACK	$ 5.80	$ 4.25	$ 3.88	$ 4.54	$ 4.61

CRUDE OIL AND NGLS
NETBACKS BY TYPE

Light/Pelican Lake/ NGLs ($/bbl)					
Sales price (1)	$ 58.28	$ 69.02	$ 71.65	$ 57.68	$ 64.33
Royalties	4.65	5.53	5.39	4.39	5.00
Production expenses	11.15	11.18	14.12	12.99	12.42
NETBACK	$ 42.48	$ 52.31	$ 52.14	$ 40.30	$ 46.91
Heavy crude oil ($/bbl)					
Sales price (1)	$ 25.22	$ 50.08	$ 51.38	$ 36.11	$ 41.20
Royalties	1.98	4.71	4.76	3.78	3.88
Production expenses	11.55	12.73	12.67	11.60	12.15
NETBACK	$ 11.69	$ 32.64	$ 33.95	$ 20.73	$ 25.17

</TABLE>

NOTE: PELICAN LAKE CRUDE OIL HAS AN API OF 14(0) TO 17(0), BUT RECEIVES MEDIUM QUALITY CRUDE NETBACKS DUE TO LOWER PRODUCTION COSTS AND LOWER ROYALTY RATES.

(1) Net of transportation and blending costs and excluding risk management activities.

NETBACKS

INFORMATION BY QUARTER

<TABLE>
<CAPTION>

2005	Q1	Q2	Q3	Q4	Year Ended
<S>	<C>	<C>	<C>	<C>	<C>
AVERAGE DAILY PRODUCTION VOLUMES					
Crude oil and NGLs (bbl/d)	287,803	289,064	334,724	340,268	313,168
Natural gas (mmcf/d)	1,455	1,454	1,423	1,423	1,439
PRODUCT NETBACKS					
Crude oil and NGLs ($/bbl)					
Sales price (1)	$ 39.81	$ 42.51	$ 57.35	$ 46.38	$ 46.86
Royalties	3.39	3.33	5.11	3.89	3.97
Production expenses	11.30	11.66	11.48	10.33	11.17
Netback	$ 25.12	$ 27.52	$ 40.76	$ 32.16	$ 31.72
Natural gas ($/mcf)					
Sales price (1)	$ 6.68	$ 7.33	$ 8.61	$ 11.67	$ 8.57
Royalties	1.30	1.48	1.93	2.30	1.75
Production expenses	0.69	0.71	0.76	0.76	0.73
Netback	$ 4.69	$ 5.14	$ 5.92	$ 8.61	$ 6.09
CRUDE OIL AND NGLS NETBACKS BY TYPE					
Light/Pelican Lake/ NGLs ($/bbl)					
Sales price (1)	$ 53.14	$ 56.85	$ 66.81	$ 8.87	$ 59.16
Royalties	5.20	4.55	5.50	4.40	4.90
Production expenses	11.58	12.28	11.47	8.90	10.93
Netback	$ 36.36	$ 40.02	$ 49.84	$ 45.57	$ 43.33
Heavy crude oil ($/bbl)					
Sales price (1)	$ 25.21	$ 27.82	$ 47.25	$ 30.27	$ 33.09
Royalties	1.41	2.07	4.83	3.08	2.92
Production expenses	11.00	11.03	11.50	12.18	11.44
Netback	$ 12.80	$ 14.72	$ 30.92	$ 15.01	$ 18.73

</TABLE>

NOTE: PELICAN LAKE CRUDE OIL HAS AN API OF 14(0) TO 17(0), BUT RECEIVES MEDIUM QUALITY CRUDE NETBACKS DUE TO LOWER PRODUCTION COSTS AND LOWER ROYALTY RATES.
(1) NET OF TRANSPORTATION AND BLENDING COSTS AND EXCLUDING RISK MANAGEMENT ACTIVITIES.

<TABLE>
<CAPTION>
2007
YEAR
Q1 Q2 Q3 Q4 ENDED

<S>	<C>	<C>	<C>	<C>	<C>
SEGMENTED					
NORTH AMERICA PRODUCT					
NETBACKS					
Light/Pelican Lake/NGLs					
($/bbl)					
Sales price (1)	$ 54.13	$ 56.06	$ 60.26	$ 63.94	$ 58.66
Royalties	8.84	9.22	11.55	12.56	10.57
Production expenses	11.74	12.11	11.58	10.82	11.56
NETBACK	$ 33.55	$ 34.73	$ 37.13	$ 40.56	$ 36.53
Heavy crude oil ($/bbl)					
Sales price (1)	$ 41.24	$ 41.85	$ 48.10	$ 43.06	$ 43.66
Royalties	4.96	4.98	6.00	4.95	5.23
Production expenses	13.76	15.12	11.75	10.38	12.66
NETBACK	$ 22.52	$ 21.75	$ 30.35	$ 27.73	$ 25.77
Natural gas ($/mcf)					
Sales price (1)	$ 7.79	$ 7.47	$ 5.88	$ 6.31$	6.87
Royalties	1.50	1.11	0.90	0.95	1.12
Production expenses	0.95	0.87	0.87	0.90	0.90
NETBACK	$ 5.34	$ 5.49	$ 4.11	$ 4.46	$ 4.85
NORTH SEA PRODUCT NETBACKS					
Light crude oil ($/bbl)					
Sales price (1)	$ 68.83	$ 73.18	$ 77.55	$ 83.44	$ 74.99
Royalties	0.13	0.13	0.14	0.19	0.14
Production expenses	18.57	22.11	23.61	18.95	20.78
NETBACK	$ 50.13	$ 50.94	$ 53.80	$ 64.30	$ 54.07
Natural Gas ($/mcf)					
Sales price (1)	$ 4.49	$ 3.92	$ 5.26	$ 3.62	$ 4.26
Royalties	--	--	--	--	--
Production expenses	2.58	2.26	2.29	1.50	2.17
NETBACK	$ 1.91	$ 1.66	$ 2.97	$ 2.12$	2.09
OFFSHORE WEST AFRICA PRODUCT					
NETBACKS					
Light crude oil ($/bbl)					
Sales price (1)	$ 58.60	$ 72.84	$ 70.52	$ 81.89	$ 71.68
Royalties	3.70	7.12	6.81	7.59	6.40
Production expenses	8.93	7.98	7.00	9.32	8.32
NETBACK	$ 45.97	$ 57.74	$ 56.71	$ 64.98	$ 56.96
Natural gas ($/mcf)					
Sales price (1)	$ 5.97	$ 6.22	$ 5.31	$ 5.49	$ 5.68
Royalties	0.38	0.59	0.51	0.52	0.51
Production expenses	1.48	1.10	1.39	1.89	1.48
NETBACK	$ 4.11	$ 4.53	$ 3.41	$ 3.08	$ 3.69

</TABLE>

<TABLE>
<CAPTION>
2006
Year
Q1 Q2 Q3 Q4 Ended

<S>	<C>	<C>	<C>	<C>	<C>
SEGMENTED					
NORTH AMERICA PRODUCT					
NETBACKS					
Light/Pelican Lake/NGLs					
($/bbl)					
Sales price (1)	$ 48.83	$ 64.35	$ 65.15	$ 48.47	$ 56.52
Royalties	8.98	10.87	10.86	7.80	9.59
Production					

expenses	9.86	9.75	10.81	13.18	10.93
NETBACK	$ 29.99	$ 43.73	$ 43.48	$ 27.49	$ 36.00
Heavy crude oil ($/bbl)					
Sales price (1)	$ 25.22	$ 50.08	$ 51.38	$ 36.11	$ 41.20
Royalties	1.98	4.71	4.76	3.78	3.88
Production expenses	11.55	12.73	12.67	11.60	12.15
NETBACK	$ 11.69	$ 32.64	$ 33.95	$ 20.73	$ 25.17
Natural gas ($/mcf)					
Sales price (1)	$ 8.39	$ 6.21	$ 5.86	$ 6.70	$ 6.77
Royalties	1.73	1.13	1.12	1.29	1.31
Production expenses	0.79	0.79	0.83	0.84	0.81
NETBACK	$ 5.87	$ 4.29	$ 3.91	$ 4.57	$ 4.65
NORTH SEA PRODUCT NETBACKS					
Light crude oil ($/bbl)					
Sales price (1)	$ 68.05	$ 73.19	$ 78.68	$ 67.72	$ 72.62
Royalties	0.12	0.17	0.11	0.14	0.13
Production expenses	16.85	17.18	20.28	14.76	17.57
NETBACK	$ 51.08	$ 55.84	$ 58.29	$ 52.82	$ 54.92
Natural Gas ($/mcf)					
Sales price (1)	$ 2.38	$ 2.33	$ 2.38	$ 3.48	$ 2.66
Royalties	--	--	--	--	--
Production expenses	1.26	1.47	1.30	1.54	1.40
NETBACK	$ 1.12	$ 0.86	$ 1.08	$ 1.94	$ 1.26
OFFSHORE WEST AFRICA PRODUCT NETBACKS					
Light crude oil ($/bbl)					
Sales price (1)	$ 65.23	$ 72.97	$ 70.59	$ 63.50	$ 67.99
Royalties	1.55	1.87	4.89	3.02	2.81
Production expenses	6.08	5.61	7.97	10.05	7.45
NETBACK	$ 57.60	$ 65.49	$ 57.73	$ 50.43	$ 57.73
Natural gas ($/mcf)					
Sales price (1)	$ 5.59	$ 5.30	$ 4.97	$ 5.72	$ 5.37
Royalties	0.13	0.14	0.34	0.27	0.22
Production expenses	1.00	0.36	1.39	2.01	1.19
NETBACK	$ 4.46	$ 4.80	$ 3.24	$ 3.44	$ 3.96

</TABLE>

NOTE: PELICAN LAKE CRUDE OIL HAS AN API OF 14(0) TO 17(0), BUT RECEIVES MEDIUM QUALITY CRUDE NETBACKS DUE TO LOWER PRODUCTION COSTS AND LOWER ROYALTY RATES.
(1) NET OF TRANSPORTATION AND BLENDING COSTS AND EXCLUDING RISK MANAGEMENT ACTIVITIES.

<TABLE>
<CAPTION>

2005 Year Q1	Q2	Q3	Q4	Ended
<S>	<C>	<C>	<C>	<C>
SEGMENTED				
NORTH AMERICA PRODUCT NETBACKS				
Light/Pelican Lake/NGLs ($/bbl)				
Sales price (1)	$ 45.80	$ 49.78	$ 61.21	$ 52.10	$ 52.35
Royalties	10.64	8.77	11.49	9.62	10.13
Production expenses	8.30	8.40	9.27	8.60	8.65
NETBACK	$ 26.86	$ 32.61	$ 40.45	$ 33.88	$ 33.57
Heavy Crude Oil ($/bbl)					
Sales price (1)	$ 25.21	$ 27.82	$ 47.25	$ 30.27	$ 33.09
Royalties	1.41	2.07	4.83	3.08	2.92
Production expenses	11.00	11.03	11.50	12.18	11.44
NETBACK	$ 12.80	$ 14.72	$ 30.92	$ 15.01	$ 18.73
Natural gas ($/mcf)					
Sales price (1)	$ 6.73	$ 7.38	$ 8.69	$ 11.79	$ 8.65
Royalties	1.33	1.50	1.96	2.34	1.78
Production expenses	0.66	0.68	0.74	0.74	0.71
NETBACK	$ 4.74	$ 5.20	$ 5.99	$ 8.71	$ 6.16
NORTH SEA PRODUCT NETBACKS					
Light crude oil ($/bbl)					
Sales price (1)	$ 59.56	$ 64.81	$ 74.46	$ 66.88	$ 66.57
Royalties	0.05	0.11	0.12	0.14	0.10
Production expenses	14.91	17.41	15.15	12.11	14.94
NETBACK	$ 44.60	$ 47.29	$ 59.19	$ 54.63	$ 51.53
Natural gas ($/mcf)					
Sales price (1)	$ 3.52	$ 3.07	$ 2.64	$ 3.40	$ 3.17
Royalties	--	--	--	--	--
Production expenses	2.52	2.92	2.30	1.96	2.44
NETBACK	$ 1.00	$ 0.15	$ 0.34	$ 1.44	$ 0.73
OFFSHORE WEST AFRICA PRODUCT NETBACKS					
Light crude oil ($/bbl)					
Sales price (1)	$ 62.34	$ 58.24	$ 59.09	$ 60.19	$ 59.91
Royalties	1.90	1.81	1.54	1.57	1.62
Production expenses	11.43	8.47	5.81	5.62	6.50
NETBACK	$ 49.01	$ 47.96	$ 51.74	$ 53.00	$ 51.79
Natural gas ($/mcf)					
Sales price (1)	$ 7.67	$ 6.88	$ 5.52	$ 5.13	$ 5.91
Royalties	0.23	0.21	0.13	0.14	0.16
Production expenses	1.25	1.37	1.09	0.80	1.05
NETBACK	$ 6.19	$ 5.30	$ 4.30	$ 4.19	$ 4.70

</TABLE>

NOTE: PELICAN LAKE CRUDE OIL HAS AN API OF 14(0) TO 17(0), BUT RECEIVES MEDIUM QUALITY CRUDE NETBACKS DUE TO LOWER PRODUCTION COSTS AND LOWER ROYALTY RATES.
(1) NET OF TRANSPORTATION AND BLENDING COSTS AND EXCLUDING RISK MANAGEMENT ACTIVITIES.

F. HISTORICAL DRILLING ACTIVITY BY PRODUCT

The following table sets forth the gross and net wells in which the Company has participated for the period indicated:

Year Ended Dec 31	2007		2006	
	GROSS	NET	Gross	Net
Natural gas	478	383	855	641
Crude oil	655	592	666	603
Service/Stratigraphic	256	254	376	375
Dry holes	107	93	133	119
Total	1,496	1,322	2,030	1,738
Total success rate (excluding service and stratigraphic test wells)	91%		91%	

G. 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.

Year Ended Dec 31 ($ millions)	2007	2006
Net property (dispositions) aquisitions (1)	$ (39)	$ 4,733
Land acquisition and retention	95	210
Seismic evaluations	124	130
Well drilling, completion and equipping	1,642	2,340
Production and related facilities	1,205	1,314
Total net reserve replacement expenditures	3,027	8,727
Horizon Project:		
Phase 1 construction costs	2,740	2,768
Phase 2/3 costs	124	79
Capitalized interest, stock-based compensation and other	437	338
Total Horizon Project	3,301	3,185
Midstream	6	12
Abandonments ((2))	71	75
Head office	20	26
TOTAL NET CAPITAL EXPENDITURES	$ 6,425	12,025

CAPITAL EXPENDITURES BY QUARTER

<TABLE>
<CAPTION>
2007 Three Months Ended

($ millions)	Mar 31	Jun 30	Sep 30	Dec 31	
<S>	<C>	<C>	<C>	<C>	
Net property acquisitions (dispositions) (1)	$ 46	$ 15	$ 7	$ (107)	
Land acquisition and retention	29	22	29	15	
Seismic evaluation	50	34	23	17	
Well drilling, completion and equipping	714	288	299	341	
Production and related facilities	334	243	238	390	
Total net reserve replacement expenditures	1,173	602	596	656	
Horizon Project:					
Phase 1 construction costs	674	704	671	691	
Phase 2/3 costs	44	19	28	33	
Capitalized interest, stock-based compensation and other	91	118	120	108	
Total Horizon Project	809	841	819	832	
Midstream	2	--	2	2	
Abandonments ((2))	20	13	22	16	
Head office	5	4	3	8	
Total net capital expenditures	$ 2,009	$ 1,460	$ 1,442	$ 1,514	

</TABLE>

CAPITAL EXPENDITURES BY QUARTER

<TABLE>
<CAPTION>
2006 Three Months Ended

($ millions)	Mar 31	Jun 30	Sep 30	Dec 31	
<S>	<C>	<C>	<C>	<C>	
Net property acquisitions (dispositions) (1)	$ 12	$ 7	$ (6)	$ 4,720	
Land acquisition and retention	99	54	29	28	
Seismic evaluation	52	35	26	17	
Well drilling, completion and equipping	936	418	524	462	
Production and related facilities	500	233	270	311	
Total net reserve replacement expenditures	1,599	747	843	5,538	
Horizon Project					
Phase 1 construction costs	616	680	727	745	
Phase 2/3 costs	1	6	18	54	
Capitalized interest, stock-based compensation and other	69	96	39	134	
Total Horizon Project	686	782	784	933	
Midstream	3	6	2	1	
Abandonments ((2))	15	17	24	19	
Head office	6	6	8	6	
Total net capital expenditures	$ 2,309	$ 1,558	$ 1,661	$ 6,497	

(1) INCLUDES BUSINESS COMBINATIONS.
(2) ABANDONMENTS REPRESENT EXPENDITURES TO SETTLE ASSET RETIREMENT OBLIGATIONS AND HAVE BEEN REFLECTED AS CAPITAL EXPENDITURES IN THIS TABLE.
</TABLE>

H. UNDEVELOPED ACREAGE

The following table summarizes the Company's working interest holdings in core region undeveloped acreage as at December 31, 2007:

(thousands)	Gross Acres	Net Acres
North America		
Alberta	10,563	9,001
British Columbia	3,317	2,373
Saskatchewan	890	775
Manitoba	11	11
North Sea		
United Kingdom	356	287
Offshore West Africa		
Cote d'Ivoire	95	55
Gabon	152	151
Total	15,384	12,653

I. DEVELOPED ACREAGE

The following table summarizes the Company's working interest holdings in core region developed acreage as at December 31, 2007:

(thousands)	Gross Acres	Net Acres
North America		
Alberta	6,081	4,805
British Columbia	1,357	1,024
Saskatchewan	812	590
Manitoba	5	5
North Sea		
United Kingdom	122	88
Offshore West Africa		
Cote d'Ivoire	7	4
Total	8,384	6,516

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:

Year Ended Dec 31 ($ millions, except per share information)	2007	2006
Revenues(1)(net of royalties)	$ 11,152	$ 10,398
Cash flow from operations	$ 6,198	$ 4,932
Per common share - basic	$ 11.49	$ 9.18
- diluted	$ 11.49	$ 9.18
Net earnings	$ 2,608	$ 2,524
Per common share - basic	$ 4.84	$ 4.70
- diluted	$ 4.84	$ 4.70
Total assets	$ 36,114	$ 33,160
Total long-term debt	$ 10,940	$ 11,043

2007 Three Months Ended ($ millions, except per share information)	Mar 31	Jun 30	Sep 30	Dec 31
Revenues (net of royalties)	$ 2,742	$ 2,821	$ 2,732	$ 2,857
Net earnings	$ 269	$ 841	$ 700	$ 798
Per common share - basic and diluted	$ 0.50	$ 1.56	$ 1.30	$ 1.48

2006 Three Months Ended ($ millions, except per share information)	Mar 31	Jun 30	Sep 30	Dec 31
Revenues (1) (net of royalties)	$ 2,352	$ 2,739	$ 2,798	$ 2,509
Net (loss) earnings	$ 57	$ 1,038	$ 1,116	$ 313
Per common share - basic and diluted	$ 0.11	$ 1.93	$ 2.08	$ 0.58

(1) BLENDING COSTS PREVIOUSLY NETTED AGAINST GROSS REVENUES IN PRIOR YEARS HAVE BEEN RECLASSIFIED TO TRANSPORTATION AND BLENDING EXPENSE TO CONFORM TO THE PRESENTATION ADOPTED IN 2006.

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 B 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 to longer 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.

2007 Monthly Historical Trading on Toronto Stock Exchange

Month	High	Low	Close	Volume Traded
January	$ 62.60	$ 52.45	$ 58.84	47,395,230
February	$ 61.19	$ 57.62	$ 58.73	34,356,234
March	$ 65.50	$ 57.01	$ 63.75	35,412,762
April	$ 68.54	$ 63.71	$ 66.14	24,726,552
May	$ 72.31	$ 65.48	$ 71.09	30,970,877
June	$ 74.99	$ 67.01	$ 70.78	38,391,312
July	$ 77.80	$ 70.04	$ 73.21	29,655,617
August	$ 73.52	$ 65.43	$ 72.19	37,051,383
September	$ 80.02	$ 71.25	$ 75.56	34,242,541
October	$ 78.98	$ 71.05	$ 78.56	44,953,346
November	$ 79.91	$ 64.50	$ 64.92	46,778,688
December	$ 73.72	$ 64.24	$ 72.58	25,099,487

On January 20, 2005, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of TSX and the NYSE, commencing January 24, 2005 and ending January 23, 2006, to purchase for cancellation up to 13,409,006 (26,818,012 post May 20, 2005 two-for-one stock split) common shares of the Company, being 5% of the 268,180,123 (536,360,246 post May 20, 2005 two-for-one stock split) common shares of the Company outstanding on January 12, 2005. Under this program, the Company purchased a total of 850,000 common shares for cancellation at a weighted average purchase price of $53.26 for each common share purchased, $53.29 after costs.

At the Annual and Special Meeting of Shareholders held May 5, 2005, the shareholders passed a special resolution amending the Articles of the Company to divide the issued and outstanding Common Shares on a two-for-one basis. The subdivision of the Common Shares occurred on May 20, 2005.

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. The Company has decided not to renew the Normal Course Issuer Bid until subsequent to the completion of Phase 1 of the Horizon Project.

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, restated for the two-for-one subdivision of the common shares which occurred in May 2005, 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.

	2007	2006	2005
Cash dividends declared per common share	$ 0.34	$ 0.30	$ 0.24

In February 2008 the Board of Directors approved an 18% increase in the 2008 quarterly dividend from $0.085 per common share to $0.10 per common share, effective with the April 1, 2008 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:

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Catherine M. Best Calgary, Alberta Canada	Director (2)(4) (age 54)	Executive Vice-President, Risk Management and Chief Financial Officer of the Calgary Health Region, a fully integrated publicly funded health care system, from 2002 to present; Vice-President, Corporate Services and Chief Financial Officer of the Calgary Health Region from February 2000 to 2002; prior thereto with Ernst & Young since 1980, most recently as a Corporate Audit Partner from 1991 to 2000. Has served continuously as a director of the Company since November 2003. Currently serving on the board of directors of Enbridge Income Fund and Superior Plus Income Fund.
N. Murray Edwards Calgary/Banff, Alberta Canada	Vice-Chairman and Director(3) (age 48)	President, Edco Financial Holdings Ltd. (a private management and consulting company). Has served continuously as a director of the Company since September 1988. Currently serving on the board of directors of Ensign Energy Services Inc. and Magellan Aerospace Corporation.
Honourable Gary A. Filmon Winnipeg, Manitoba Canada	Director (1)(2) (age 65)	Consultant, The Exchange Group (business consulting firm based in Winnipeg, Manitoba). Prior thereto, served as Premier of Manitoba from 1988 to 1999. Has served continuously as a director of the Company since February 2006. Currently serving on the board of directors of MTS Allstream Inc., Pollard Banknote Income Fund, Arctic Glacier Income Trust, Exchange Industrial Income Fund, Wellington West Capital Inc. and FWS Construction Inc.
Ambassador Gordon D. Giffin Atlanta, Georgia USA	Director (1)(2) (age 58)	Senior Partner, McKenna Long & Aldridge LLP (law firm) since May 2001; prior thereto United States Ambassador to Canada. Has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of Abitibi Bowater Inc.; Canadian National Railway Company; Canadian Imperial Bank of Commerce, Ontario Energy Savings Corp. and, Transalta Corporation.
John G. Langille Calgary, Alberta Canada	Vice-Chairman and Director (age 62)	Officer of the Company. Has served continuously as a director of the Company since June 1982.
Steve W. Laut Calgary, Alberta Canada	President and Chief Operating Officer and Director (age 50)	President and Chief Operating Officer of the Company since April 2005. Prior thereto Executive Vice-President, Operations 2001 to 2003 and most recently Chief Operating Officer 2003 to 2005. Has served continuously as a director of the Company since August 2006.
Keith A.J. MacPhail Calgary, Alberta Canada	Director (3)(5) (age 51)	Chairman, President and Chief Executive Officer, Bonavista Energy Trust since November 1997 and Chairman, NuVista Energy Ltd since July 2003. Has served continuously as a director of the Company since October 1993. Currently serving on the board of directors of Bonavista Energy Trust and NuVista Energy Ltd.
Allan P. Markin Calgary, Alberta Canada	Chairman and Director(5) (age 62)	Chairman of the Company. Has served continuously as a director of the Company since January 1989.

<TABLE>
<CAPTION>

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
<S>	<C>	<C>
Norman F. McIntyre Calgary, Alberta Canada	Director (3)(4)(5) (age 62)	An independent businessman. Prior thereto Executive Vice-President, Petro-Canada from 1995 to 2002 and most recently President, Petro-Canada 2002 to 2004. Has served continuously as a director of the Company since July 2005. Currently serving on the board of directors of Petro Andina Resources Inc.
Frank J. McKenna Cap Pele, New Brunswick Canada	Director (1)(4) (age 60)	Deputy Chair, TD Bank Financial Group. Prior thereto Premier of New Brunswick from 1987 to 1997; Counsel to Atlantic Canada law firm McInnes Cooper from 1998 to 2005, and most recently Canadian Ambassador to the United States from 2005 to 2006. He has served continuously as a director of the Company since August 2006. Currently serving on the board of directors of Brookfield Asset Management Inc.
James S. Palmer, C.M., A. O. E., Q.C. Calgary, Alberta Canada	Director (3)(4)(5) (age 79)	Chairman and a Partner of Burnet, Duckworth & Palmer LLP (law firm). Has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Magellan Aerospace Corporation.
Dr. Eldon R. Smith, OC, M.D. Calgary, Alberta Canada	Director (4)(5) (age 68)	President of Eldon R. Smith & Associates Ltd., and he is Emeritus Professor and Former Dean, Faculty of Medicine, University of Calgary. Has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Vasogen Inc., Sernova Corp.; Aston Hill Financial; and Ventripoint Diagnostics Inc.
David A. Tuer Calgary, Alberta Canada	Director (1)(2)(3) (age 58)	Chairman, Calgary Health Region since October 2001 and Executive Vice-Chairman BA Energy Inc. from April 2005 to February 2008. Prior thereto President and Chief Executive Officer, PanCanadian Energy Corporation from December 1994 to October 2001, President and CEO of Hawker Resources Inc. (independent oil and natural gas company) from January 2003 to March 2005 and most recently President, Value Creation Inc. from April 2005 to February 2006. Has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of Daylight Resources Trust; Xtreme Coil Drilling Corp.; Canadian Phoenix Resources and, Altalink Management LLP., a private limited partnership.
Real M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 57)	Officer of the Company.
Real J. H. Doucet Calgary, Alberta Canada	Senior Vice-President, Oil Sands (age 55)	Officer of the Company.
Allen M. Knight Calgary, Alberta Canada (age 58)	Senior Vice-President, International & Corporate Development	Officer of the Company.
Tim S. McKay Calgary, Alberta Canada	Senior Vice-President, Operations (age 46)	Officer of the Company.
Douglas A. Proll Calgary, Alberta Canada (age 57)	Chief Financial Officer and Senior Vice-President, Finance	Officer of the Company.

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NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
<S>	<C>	<C>
Lyle G. Stevens Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 53)	Officer of the Company.
Jeffrey W. Wilson Calgary, Alberta Canada	Senior Vice-President, Exploration (age 55)	Officer of the Company since September 2003; prior thereto Exploration Manager of the Company.
Jeffrey J. Bergeson Calgary, Alberta Canada	Vice-President, Exploitation West (age 51)	Officer of the Company since May 2007; prior thereto Exploitation Manager of the Company until May 2007.
Corey B. Bieber Calgary, Alberta Canada	Vice-President, Finance and Investor Relations (age 44)	Officer of the Company since April 2005; prior thereto Treasurer of the Company March 2001 to July 2002; Director, Investor Relations of Canada the Company from July 2002 to April 2005 and most recently Vice-President, Investor Relations April 2005 to February 2007.
Mary-Jo E. Case Calgary, Alberta Canada	Vice-President, Land (age 49)	Officer of the Company.
William R. Clapperton Calgary, Alberta Canada Affairs (age 45)	Vice-President, Regulatory, Stakeholder and Environmental	Officer of the Company.
James F. Corson Calgary, Alberta Canada (age 57)	Vice-President, Human Resources, Horizon	Officer of the Company since January 2007; prior thereto Vice-President, Human Resources of Qatar Petroleum Corp. from March 1997 to July 2005 and most recently Director Human Resources and Stakeholder Relations of the Company from July 2005 to 2007.
Randall S. Davis Calgary, Alberta Canada	Vice-President, Finance and Accounting (age 41)	Officer of the Company since July 2004; prior thereto Manager, Financial Reporting of the Company to July 2002; Financial Controller of the Company from July 2002 to July 2004 and most recently Vice-President Financial Accounting and Controls July 2004 to February 2007.
Allan E. Frankiw Calgary, Alberta Canada	Vice-President, Production, Central (age 51)	Officer of the Company since March 2007; prior thereto Manager Midstream for Anadarko Canada Corporation from November 1998 to March 2005, Manager Facilities & Construction for Anadarko Canada Corporation from April 2005 to November 2006, and most recently Manager Production of the Company from November 2006 to March 2007.
Jerome W. Harvey Calgary, Alberta Canada	Vice-President, Commercial Operations (age 54)	Officer of the Company since April 2004; prior thereto Manager, Commercial Operations.
Peter J. Janson Calgary, Alberta Canada	Vice-President, Engineering Integration (age 50)	Officer of the Company since December 2004; prior thereto Director, Production Planning and Control at Suncor Oil Sands to June 2000, Director, Health and Safety and Environment from June 2000 to November 2002 at Suncor Oil Sands and most recently Director, Engineering Integration of the Company from November 2002 to December 2004.

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NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
<S>	<C>	<C>
Philip A. Keele Calgary, Alberta Canada Oil Sands (age 48)	Vice-President, Mining, Project Horizon	Officer of the Company since December 2004; prior thereto Mine Manager at Fording Coal Limited to February 2001, Chief Mine Engineer of the Company February 2001 to September 2002 and most recently Director, Mine Engineering of the Company from September 2002 to December 2004.
Cameron S. Kramer Calgary, Alberta Canada	Vice-President, Development Operations (age 40)	Officer of the Company.
Leon Miura Calgary, Alberta (age 53)	Vice-President, Upgrading	Officer of the Company since August 2003; prior thereto held progressively senior positions at Petroleos de Venezuela including Canada Cerro Negro Execution Manager, Heavy Oil Upgrading from 1997 to 2001 and most recently Nitrogen Injection Project Director, Secondary Recovery at Petroleos de Venezuela 2002 to 2003.
S. John Parr Calgary, Alberta Canada	Vice-President, Production, East (age 46)	Officer of the Company since April 2004; prior thereto Production Engineer, NE Gas of the Company to July 2001, Manager, Production Engineering of the Company from July 2001 to June 2002 and most recently Production Manager, Heavy Oil of the Company from July 2002 to April 2004.
David A. Payne Calgary, Alberta Canada	Vice-President, Exploitation, Central (age 46)	Officer of the Company since October 2004; prior thereto Exploitation Manager, Thermal Heavy of the Company to July 2000, Director, Exploitation of CNR International (U.K.) Limited a wholly-owned subsidiary of the Company from July 2000 to August 2003, Exploitation Manager, Technical Projects of the Company from August 2003 to October 2004, Vice-President, Exploitation, West from October 2004 to April 2007, and most recently Vice-President, Exploitation, East from May 2007 to February 2008.
William R. Peterson Calgary, Alberta Canada	Vice-President, Production, West (age 41)	Officer of the Company since April 2004; prior thereto Production Manager, West of the Company.
John C. Puckering Calgary, Alberta Canada	Vice President, Site Development (age 61)	Officer of the Company since April 2004; prior thereto General Manager DCL Construction Inc. to November 2001, President of 960925 Alberta Ltd. from November 2001 to April 2002, Manager, Site Development of the Company from May 2002 to December 2002 and most recently General Manager Site Development of the Company from January 2003 to April 2004.
Timothy G. Reed Calgary, Alberta Canada	Vice-President, Human Resources (age 51)	Officer of the Company since January 2007; prior thereto Manager, Human Resources of the Company 2000 to 2005 and most recently Director Human Resources 2005 to January 2007.
Joy P. Romero Calgary, Alberta Canada	Vice President, Bitumen Production (age 51)	Officer of the Company since March 2008; prior thereto Manager, Bitumen Production Process of the Company January 2001 to September 2002 and most recently Director, Bitumen Production Process of the Company from September 2002 to March 2008.
Sheldon L. Schroeder Fort McMurray, Alberta Canada	Vice-President, Project Control (age 40)	Officer of the Company since April 2004; prior thereto engineer with 729248 Alberta Ltd. to June 2001, Project Control Manager of the Company from June 2001 to September 2002 and most recently Director, Project Control of the Company from September 2002 to April 2004.

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NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
<S>	<C>	<C>
Kendall W. Stagg Calgary, Alberta Canada	Vice-President, Exploration, West (age 46)	Officer of the Company since October 2004; prior thereto Cardium Geophysicist of the Company to April 2001, Chief Geophysicist of the Company from April 2001 to June 2002 and most recently Manager Exploration, B. C. of the Company from June 2002 to September 2004.
Scott G. Stauth Calgary, Alberta Canada	Vice-President, Field Operations (age 50)	Officer of the Company since November 2006; prior thereto Operations Superintendent of the Company April 1997 to April 2003 and most recently Manager, Eastern Field Operations of the Company April 2003 to November 2006.
Stephen C. Suche Calgary, Alberta Canada (age 48)	Vice-President, Information and Corporate Services	Officer of the Company since July 2006; prior thereto Manager Information and Corporate Services of the Company January 2000 to July 2006.
Domenic Torriero Calgary, Alberta Canada	Vice-President, Exploration, Central (age 43)	Officer of the Company since November 2006; prior thereto Vice-President Geology and Geophysics of Petrovera Resources Limited January 1999 to March 2004 and most recently Exploration Manager of the Company March 2004 to November 2006.
Grant M. Williams Calgary, Alberta Canada	Vice-President, Exploration, East (age 50)	Officer of the Company since March 2007; prior thereto Chief Geophysicist of the Company October 1999 to October 2003 and most recently Manager, Exploration Heavy Oil of the Company October 2003 to April 2007.
Daryl G. Youck Calgary, Alberta Canada	Vice-President, Exploitation, East (age 39)	Officer of the Company since February 2008; prior thereto Manager, Exploitation of the Company July 2002 to February 2008.
Lynn M. Zeidler Calgary, Alberta Canada (age 51)	Vice-President, Utilities and Offsites and Horizon Construc- tion Management	Officer of the Company since August 2003; prior thereto held progressively senior positions at Shell Canada Limited including on secondment from Shell Canada Limited as Manager-Tier 1 Implementation at Sable Offshore Energy Inc to September 2000 and most recently General Project Manager, Athabasca Oil Sands Project at Shell Canada Limited October 2000 to May 2003 and concurrently as Vice President & Project Director, Muskeg River Mine at Albian Sands Energy Inc. May 2002 to July 2003 and General Manager Claims Athabasca Oil Sands Project at Shell Canada Limited May 2003 to July 2003.
Bruce E. McGrath Calgary, Alberta Canada	Corporate Secretary (age 58)	Officer of the Company.

</TABLE>

(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 and special meeting of shareholders held on May 3, 2007. All of the current directors are standing for election at the Annual General Meeting of Shareholders scheduled for May 8, 2008.

As at December 31, 2007, 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 5% 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, and 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 Multilateral 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 2007 approved specified audit and non-audit services to be performed by PricewaterhouseCoopers ("PwC"). The services provided include: (i) the annual audit of the Corporation's internal controls and December 31, 2007 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	2007	2006
Audit fees	$ 2,729,315	$ 3,126,287
Audit related fees	164,000	121,353
Tax related fees	154,459	134,025
All other fees	9,440	9,516
	$ 3,057,214	$ 3,391,181

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 February 26, 2008 in respect of the Company's consolidated financial statements with accompanying notes as at and for the three years ended December 31, 2007 and the Company's internal control over financial reporting as at December 31, 2007. 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, Ryder Scott Company 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, 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 19, 2008 in connection with the Annual General Meeting of Shareholders of Canadian Natural to be held on May 8, 2008 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, 2007 found on pages 39 to 68, 69 to 96 and 97 to 101 respectively, of the 2007 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"

AMENDED 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, 2007. The reserves data consist of the following:

(a) (i) proved conventional crude oil, natural gas liquids and natural gas reserve quantities estimated as at December 31, 2007 using constant prices and costs;

(ii) the related estimated net present value; and

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

(b) (i) both proved, and proved and probable conventional crude oil, natural gas liquids and natural gas reserve quantities estimated as at December 31, 2007 using forecast prices and costs; and

(ii) the related estimated net present value.

(c) (i) both proved, and proved and probable bitumen and synthetic crude oil reserve quantities relating to surface mineable oil sands projects estimated as at December 31, 2007.

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.

3. 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").

4. 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 above.

5. The following table sets forth the estimated net present value of conventional reserves (before deduction of income taxes) attributed to proved conventional crude oil, NGL and natural gas reserves quantities, estimated using constant 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, 2007 except as noted in 1(c)(i), and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's management and board of directors:

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NET PRESENT VALUES OF CONVENTIONAL RESERVES					
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR	DESCRIPTION AND PREPARATION DATE OF EVALUATION REPORT	LOCATION OF RESERVES (GEOGRAPHIC AREA)	(BEFORE INCOME TAXES, 10% DISCOUNT RATE) ($ MILLIONS) AUDITED	EVALUATED	REVIEWED	TOTAL
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Sproule Associates Ltd.	Sproule Evaluated the P&NG Reserves as reported February 11th, 2008.	Canada, USA	$0	$22,325	$0	$22,325
Ryder Scott Company	Ryder Scott Evaluated the P&NG Reserves as reported February 11th, 2008.	United Kingdom and Offshore West Africa	$0	$12,253	$0	$12,253
TOTALS			$0	$34,578	$0	$34,578

</TABLE>

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, 2007. 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 Company's conventional crude oil and natural gas activities.

6. 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.

7. We have no responsibility to update our evaluation for events and circumstances occurring after their respective preparation dates.

8. Reserves are estimates only, and not exact quantities. In addition, as the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

February 11th, 2008

SPROULE ASSOCIATES LIMITED
CALGARY, ALBERTA, CANADA

ORIGINAL SIGNED BY:

/s/ Harry J. Helwerda

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

ORIGINAL SIGNED BY:

/s/ Doug Ho

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

ORIGINAL SIGNED BY:

/s/ R. Keith MacLeod

R. Keith MacLeod, P.Eng.
President

RYDER SCOTT COMPANY
CALGARY, ALBERTA, CANADA

ORIGINAL SIGNED BY:

/s/ Jane L. Tink

Jane L. Tink, P.Eng.,
Vice-President

GLJ PETROLEUM CONSULTANTS
CALGARY, ALBERTA, CANADA

ORIGINAL SIGNED BY:

/s/ James H. Willmon

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 conventional crude oil, natural 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, 2007 using constant prices and costs;

(ii) the related estimated net present value; and

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

(b) (i) both proved, and proved and probable conventional crude oil, NGLs and natural gas reserve quantities estimated as at December 31, 2007 using forecast prices and costs;

(ii) the related estimated net present value; and,

(c) (i) both proved, and proved and probable bitumen and synthetic crude oil reserve quantities relating to surface mineable oil sands operations estimated as at December 31, 2007.

Sproule Associates Limited, Ryder Scott Company and GLJ Petroleum Consultants, all 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 placed by management affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the Board of Directors has reviewed the Corporation's procedures for assembling and reporting other information associated with crude oil and natural gas 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 the reserves data and other crude oil and natural gas and surface mineable oil sands information;

(b) the filing of the reports of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Reserves data are estimates only, and are not exact quantities. In addition, as the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

ORIGINAL SIGNED BY:

Steve W. Laut
President and Chief Operating Officer

ORIGINAL SIGNED BY:

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

ORIGINAL SIGNED BY:

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

ORIGINAL SIGNED BY:

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

Dated this 26th day of February, 2008
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. The Audit Committee's primary duties and responsibilities are to:

1. ensure that the Corporation's management has designed and implemented an effective system of internal financial controls;

2. monitor and report on 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 and performance of the Corporation's independent auditors;

5. monitor the performance of the internal auditing 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. 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 designed, implemented and is maintaining an effective system of internal controls;

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 approve 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;

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; and,

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 and approve 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 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 Corporation's financial and auditing procedures and 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 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 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 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.

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 Rule 15(d)-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, 2007. 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.

(signed) Steve W. Laut

STEVE W. LAUT
President & Chief Operating Officer
Senior Vice President, Finance

(signed) Douglas A. Proll

DOUGLAS A. PROLL, CA
Chief Financial Officer &

February 26, 2008
Calgary, Alberta, Canada

[GRAPHIC OMITTED]
[LOGO - PRICEWATERHOUSECOOPERS LLP]

| PRICEWATERHOUSECOOPERS LLP
| CHARTERED ACCOUNTANTS
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| Calgary, Alberta
| Canada T2P 5L3
| Telephone +1 (403) 509 7500
| Facsimile +1 (403) 781 1825

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Canadian Natural Resources Limited

We have completed integrated audits of the consolidated financial statements and internal control over financial reporting of Canadian Natural Resources Limited (the "Company") as at December 31, 2007 and 2006 and an audit of its 2005 consolidated financial statements. Our opinions, based on our audits, are presented below.

CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated balance sheets of the Company as at December 31, 2007 and December 31, 2006, 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, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the Company's financial statements as at December 31, 2007 and for each of the years in the two year period then ended in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). We conducted our audit of the Company's financial statements for the year ended December 31, 2005 in accordance with Canadian generally accepted auditing standards. 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, 2007 and December 31, 2006 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited the Company's internal control over financial reporting as at December 31, 2007, 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 effectiveness of 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

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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, 2007 based on criteria established in Internal Control -- Integrated Framework issued by the COSO.

(signed) PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
February 26, 2008

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 change described in Note 2 to the consolidated financial statements. Our report to the shareholders dated February 26, 2008 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.

(signed) PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
February 26, 2008

<TABLE>
<CAPTION>
CONSOLIDATED BALANCE SHEETS

As at December 31 (millions of Canadian dollars)	2007	2006
<S>	<C>	<C>
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 21	$ 23
Accounts receivable and other	1,662	1,947
Future income tax (note 8)	480	163
Current portion of other long-term assets (note 3)	18	106
	2,181	2,239
PROPERTY, PLANT AND EQUIPMENT (note 4)	33,902	30,767
OTHER LONG-TERM ASSETS (note 3)	31	154
	$ 36,114	$ 33,160
LIABILITIES		
CURRENT LIABILITIES		
Accounts payable	379	842
Accrued liabilities	1,567	1,618
Current portion of other long-term liabilities (note 6)	1,617	611
	3,563	3,071
LONG-TERM DEBT (note 5)	10,940	11,043
OTHER LONG-TERM LIABILITIES (note 6)	1,561	1,393
FUTURE INCOME TAX (note 8)	6,729	6,963
	22,793	22,470
SHAREHOLDERS' EQUITY		
SHARE CAPITAL (note 9)	2,674	2,562
RETAINED EARNINGS	10,575	8,141
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) (note 10)	72	(13)
	13,321	10,690
	$ 36,114	$ 33,160
COMMITMENTS AND CONTINGENCIES (NOTE 13)		

</TABLE>

Approved by the Board of Directors:

(signed) Catherine M. Best (signed) N. Murray Edwards

CATHERINE M. BEST
Chair of the Audit Committee and Director

N. MURRAY EDWARDS
Vice-Chairman of the Board of Directors and Director

<TABLE>
<CAPTION>
CONSOLIDATED STATEMENTS OF EARNINGS

For the years ended December 31
(millions of Canadian dollars, except per common share amounts) 2007 2006 2005

<S>	<C>	<C>	<C>
REVENUE	$ 12,543	$ 11,643	$ 11,130
Less: royalties	(1,391)	(1,245)	(1,366)
REVENUE, NET OF ROYALTIES	11,152	10,398	9,764
EXPENSES			
Production	2,184	1,949	1,663
Transportation and blending	1,570	1,443	1,293
Depletion, depreciation and amortization	2,863	2,391	2,013
Asset retirement obligation accretion (note 6)	70	68	69
Administration	208	180	151
Stock-based compensation (note 6)	193	139	723
Interest, net	276	140	149
Risk management activities (note 12)	1,562	312	1,952
Foreign exchange (gain) loss	(471)	122	(132)
8,455	6,744	7,881	
EARNINGS BEFORE TAXES	2,697	3,654	1,883
Taxes other than income tax (note 8)	165	256	194
Current income tax expense (note 8)	380	222	286
Future income tax (recovery) expense (note 8)	(456)	652	353
NET EARNINGS	$ 2,608	$ 2,524	$ 1,050
NET EARNINGS PER COMMON SHARE (note 11)			
Basic	$ 4.84	$ 4.70	$ 1.96
Diluted	$ 4.84	$ 4.70	$ 1.95

</TABLE>

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<CAPTION>
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

For the years ended December 31 (millions of Canadian dollars)	2007	2006	2005
<S>	<C>	<C>	<C>
SHARE CAPITAL			
Balance - beginning of year	$ 2,562	$ 2,442	$ 2,408
Issued upon exercise of stock options	21	21	9
Previously recognized liability on stock options exercised for common shares	91	101	29
Purchase of common shares under Normal Course Issuer Bid	-	(2)	(4)
Balance - end of year	2,674	2,562	2,442
RETAINED EARNINGS			
Balance - beginning of year, as originally reported	8,141	5,804	4,922
Transition adjustment on adoption of financial instruments standards (note 2)	10	-	-
Balance - beginning of year, as restated	8,151	5,804	4,922
Net earnings	2,608	2,524	1,050
Dividends on common shares (note 9)	(184)	(161)	(127)
Purchase of common shares under Normal Course Issuer Bid	-	(26)	(41)
Balance - end of year	10,575	8,141	5,804
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) (note 2)			
Balance - beginning of year	(13)	(9)	(6)
Transition adjustment on adoption of financial instruments standards	159	-	-
Balance - beginning of year, after effect of transition adjustment	146	(9)	(6)
Other comprehensive loss, net of taxes	(74)	(4)	(3)
Balance - end of year	72	(13)	(9)
SHAREHOLDERS' EQUITY	$ 13,321	$ 10,690	$ 8,237

<CAPTION>
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (millions of Canadian dollars)	2007	2006	2005
<S>	<C>	<C>	<C>
NET EARNINGS	$ 2,608	$ 2,524	$ 1,050
NET CHANGE IN DERIVATIVE FINANCIAL INSTRUMENTS DESIGNATED AS CASH FLOW HEDGES			
Unrealized income during the year, net of taxes of $6 million (2006 - $nil, 2005 - $nil)	38	-	-
Reclassification to net earnings, net of taxes of $45 million (2006 - $nil, 2005 - $nil)	(96)	-	-
	(58)	-	-
FOREIGN CURRENCY TRANSLATION ADJUSTMENT			
Translation of net investment	(16)	(4)	(12)
Hedge of net investment, net of taxes	-	-	9
	(16)	(4)	(3)
OTHER COMPREHENSIVE LOSS, NET OF TAXES	(74)	(4)	(3)
COMPREHENSIVE INCOME	$ 2,534	$ 2,520	$ 1,047

</TABLE>

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<CAPTION>
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31
(millions of Canadian dollars)

	2007	2006	2005
<S>	<C>	<C>	<C>
OPERATING ACTIVITIES			
Net earnings	$ 2,608	$ 2,524	$ 1,050
Non-cash items			
Depletion, depreciation and amortization	2,863	2,391	2,013
Asset retirement obligation accretion	70	68	69
Stock-based compensation	193	139	723
Unrealized risk management loss (gain)	1,400	(1,013)	925
Unrealized foreign exchange (gain) loss	(524)	134	(103)
Deferred petroleum revenue tax expense (recovery)	44	37	(9)
Future income tax (recovery) expense	(456)	652	353
Deferred charges and other	38	(2)	(31)
Abandonment expenditures	(71)	(75)	(46)
Net change in non-cash working capital (note 14)	(346)	(679)	(147)
	5,819	4,176	4,797
FINANCING ACTIVITIES			
(Repayment) issue of bank credit facilities, net	(1,925)	6,499	(435)
Issue of medium-term notes	273	400	400
Repayment of senior unsecured notes	(33)	-	(194)
Issue of US dollar debt securities	2,553	788	-
Repayment of preferred securities	-	-	(107)
Issue of common shares on exercise of stock options	21	21	9
Dividends on common shares	(178)	(153)	(121)
Purchase of common shares	-	(28)	(45)
Net change in non-cash working capital (note 14)	8	37	19
	719	7,564	(474)
INVESTING ACTIVITIES			
Expenditures on property, plant and equipment	(6,464)	(7,266)	(5,340)
Net proceeds on sale of property, plant and equipment	110	71	454
Net expenditures on property, plant and equipment	(6,354)	(7,195)	(4,886)
Acquisition of Anadarko Canada Corporation (note 15)	-	(4,641)	-
Net proceeds on sale of other assets	-	-	11
Net change in non-cash working capital (note 14)	(186)	101	542
	(6,540)	(11,735)	(4,333)
(DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(2)	5	(10)
CASH AND CASH EQUIVALENTS - BEGINNING OF YEAR	23	18	28
CASH AND CASH EQUIVALENTS - END OF YEAR	$ 21	$ 23	$ 18

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION (NOTE 14)
</TABLE>

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, 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. Each development phase ("Phase") is planned to result in incremental production capacity. 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 17.

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 for impairment calculations are based on estimates of crude oil and natural gas reserves and commodity prices, production expenses and capital costs required to develop and produce those reserves. All of the Company's reserve estimates are evaluated annually by independent engineering firms. The imprecise nature of reserves estimates makes it likely that the reserve base and the related future cash flows will be revised over time as additional data becomes available. As a result, reserve estimates are subject to measurement uncertainty and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could 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 could be material.

The calculation of income taxes requires judgment 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 expenses (recoveries).

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 could result in material changes to deferred amounts.

(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") by the Canadian Institute of Chartered Accountants ("CICA"). Accordingly, all costs relating to the exploration for and development of crude oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. 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 constitutes 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 costs for mining activities 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 ready for its intended use. Costs related to major maintenance turnaround activities will be deferred 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 benefited 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 ceases once construction is substantially complete and this Phase of the Horizon Project is available for its intended use. The Company continues to capitalize a portion of interest costs related to subsequent on-going Phases of the Horizon Project.

(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 and 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. Unproved properties are assessed periodically to determine whether impairment has occurred. When proved reserves are assigned or the value of unproved property is considered to be impaired, the cost of the unproved property or the amount of the impairment is added to costs subject to depletion. Costs for major development projects, as identified by management, are not subject to depletion until the projects are available for their intended uses. 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 located on the Horizon Project site will be amortized on the unit-of-production method based on the estimated proved and probable reserves of the Horizon Project or the productive capacity, as appropriate. 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 cash flow from the Horizon Project using proved and probable reserves and expected future prices and costs, discounted at a risk-free interest rate.

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 statement of earnings.

(K) REVENUE RECOGNITION
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.

(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 statement 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 Government State Oil Company. Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. The Government's 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 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 from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in a future period. Accordingly, North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the nature, timing and amount of capital expenditures incurred in Canada in any particular year.

(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 and 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 as defined by the CICA Handbook: 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 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 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 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 utilizes various derivative financial instruments to manage its commodity price, currency and interest rate exposures. These derivative financial instruments are not intended for trading or speculative purposes.

Effective January 1, 2007, all derivative financial instruments are recognized at estimated fair value on the consolidated balance sheet at each balance sheet date. The estimated fair value of derivative instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. However, these 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.

The Company formally documents all derivative financial instruments that are 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 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.

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. Gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in consolidated net earnings immediately.

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 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, 2008, the Company will adopt the following three new accounting 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 section also requires the disclosure of any externally-imposed capital requirements and compliance with those requirements. The section does not define capital. The section affects disclosures only and will 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 is not anticipated to have a material impact on the Company's financial statements.

FINANCIAL INSTRUMENTS
o 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 disclosures of 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 will not impact the Company's accounting for financial instruments.

In addition, the following standard was issued during 2008 and will be effective for the Company's year beginning on January 1, 2009, with earlier adoption permitted:

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. Adoption of the new standard may impact the Company's capitalization of certain costs during the development and start-up of large development projects.

(V) COMPARATIVE FIGURES
Certain prior year figures have been reclassified to conform to the presentation adopted in 2007.

2. CHANGE IN ACCOUNTING POLICY

Effective January 1, 2007, the Company adopted the following new accounting standards issued by the CICA relating to the accounting for and disclosure of financial instruments and comprehensive income:

o Section 1530 - "Comprehensive Income" introduces the concept of comprehensive income to Canadian GAAP. Comprehensive income is the change in equity (net assets) of the Company during a reporting period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except transactions with owners. The foreign currency translation adjustment, which was previously a separate component of shareholders' equity, is now recorded as part of accumulated other comprehensive income.

o Section 3251 - "Equity" replaces Section 3250 - "Surplus" and establishes standards for the presentation of equity and changes in equity during a reporting period.

o Section 3855 - "Financial Instruments - Recognition and Measurement" prescribes when a financial asset, financial liability, or non-financial derivative should be recognized on the balance sheet as well as its measurement amount.

o Section 3865 - "Hedges" replaces Accounting Guideline 13 - "Hedging Relationships" and EIC 128 - "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments" and specifies how hedge accounting is to be applied and what disclosures are necessary when hedge accounting is applied.

Adoption of these standards required the Company to record all of its derivative financial instruments on the balance sheet at estimated fair value as at January 1, 2007, including those designated as hedges. Designated hedges, other than cross currency swaps, were previously not recognized on the balance sheet but were disclosed in the notes to the financial statements. The adjustment to recognize all designated hedges on the balance sheet was recorded as an adjustment to the opening balance of retained earnings or accumulated other comprehensive income, as appropriate.

With the exception of the foreign currency translation adjustment, these standards were adopted prospectively; accordingly, comparative amounts for prior periods have not been restated. The reclassification of the foreign currency translation adjustment to other comprehensive income was applied retroactively with prior period restatement.

The effects of adopting these standards on the opening balance sheet were as follows:

JANUARY 1, 2007	
Increased current portion of other long-term assets (1)	$ 193
Decreased other long-term assets (2)	$ (16)
Decreased long-term debt (3)	$ (72)
Increased retained earnings (4)	$ 10
Increased foreign currency translation adjustment (5)	$ 13
Increased accumulated other comprehensive income (6)	$ 146
Decreased current portion of future income tax asset (7)	$ (62)
Increased future income tax liability (7)	$ 18

(1) RELATES TO THE RECOGNITION OF THE CURRENT PORTION OF THE FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS DESIGNATED AS CASH FLOW HEDGES.
(2) RELATES TO THE RECOGNITION OF THE LONG-TERM PORTION OF THE FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS DESIGNATED AS CASH FLOW AND FAIR VALUE HEDGES, AS WELL AS THE RECLASSIFICATION OF TRANSACTION COSTS AND ORIGINAL ISSUE DISCOUNTS FROM DEFERRED CHARGES TO LONG-TERM DEBT.
(3) RELATES TO THE FAIR VALUE IMPACT OF DERIVATIVE FINANCIAL INSTRUMENTS DESIGNATED AS FAIR VALUE HEDGES, AS WELL AS THE RECLASSIFICATION OF TRANSACTION COSTS AND ORIGINAL ISSUE DISCOUNTS.
(4) RELATES TO THE IMPACT ON ADOPTION OF THE MEASUREMENT OF INEFFECTIVENESS ON DERIVATIVE FINANCIAL INSTRUMENTS DESIGNATED AS CASH FLOW HEDGES.
(5) RELATES TO THE RETROACTIVE RESTATEMENT OF FOREIGN CURRENCY TRANSLATION ADJUSTMENT TO ACCUMULATED OTHER COMPREHENSIVE INCOME.
(6) RELATES TO THE RECOGNITION OF ACCUMULATED OTHER COMPREHENSIVE INCOME ARISING FROM THE MEASUREMENT OF EFFECTIVENESS ON DERIVATIVE FINANCIAL INSTRUMENTS DESIGNATED AS CASH FLOW HEDGES.
(7) RELATES TO THE FUTURE INCOME TAX IMPACTS OF THE ABOVE NOTED ADJUSTMENTS.

3. OTHER LONG-TERM ASSETS

<TABLE>
<CAPTION>

2007	2006
<S>	<C> <C>
Deferred charges	$ 28 $ 109
Risk management (note 12)	- 128
Other	21 23
49	260
Less: current portion	18 106
$ 31	$ 154

</TABLE>

4. PROPERTY, PLANT AND EQUIPMENT

<TABLE>
<CAPTION>

2007			2006		
COST	ACCUMULATED DEPLETION AND DEPRECIATION	NET	Cost	Accumulated depletion and depreciation	Net
<S>	<C>	<C>	<C>	<C>	<C>
Conventional crude oil and natural gas					
North America	$ 34,195	$ 12,162	$ 22,033	$ 31,715	$ 9,836 $ 21,879
North Sea	3,174	1,446	1,728	3,370	1,341 2,029
Offshore West Africa	1,833	645	1,188	1,685	481 1,204
Other	39	14	25	38	14 24
Horizon Project	8,651	-	8,651	5,350	- 5,350
Midstream	269	64	205	263	56 207
Head office	170	98	72	150	76 74
$ 48,331	$ 14,429	$ 33,902	$ 42,571	$ 11,804	$ 30,767

</TABLE>

During the year ended December 31, 2007, the Company capitalized administrative overhead of $47 million (2006 - $41 million, 2005 - $41 million) relating to exploration and development in the North Sea and Offshore West Africa and $312 million (2006 - $255 million, 2005 - $134 million) relating primarily to the Horizon Project in North America.

During the year ended December 31, 2007, the Company capitalized $356 million (2006 - $196 million, 2005 - $72 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:

<TABLE>
<CAPTION>

2007	2006
<S>	<C> <C>
Conventional crude oil and natural gas	
North America	$ 2,259 $ 2,244
North Sea	10 24
Offshore West Africa	138 84
Other	25 24
Horizon Project	8,651 5,350
$ 11,083	$ 7,726

</TABLE>

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, 2007:

<TABLE>
<CAPTION>

2008	2009	2010	2011	2012	thereafter	Average annual increase
<S>	<C>	<C>	<C>	<C>	<C>	<C>
CRUDE OIL AND NGLS						
North America						
WTI at Cushing (US$/bbl)	$ 89.61	$ 86.01	$ 84.65	$ 82.77	$ 82.26	2.0%
Hardisty Heavy 12(degree) API (C$/bbl)	$ 54.67	$ 52.42	$ 51.56	$ 50.38	$ 50.05	2.0%
Edmonton Par (C$/bbl)	$ 88.17	$ 84.54	$ 83.16	$ 81.26	$ 80.73	2.0%
North Sea and Offshore West Africa						
North Sea Brent (US$/bbl)	$ 87.61	$ 83.97	$ 82.57	$ 80.65	$ 80.10	2.0%
NATURAL GAS						
North America						
Henry Hub Louisiana (US$/mmbtu)	$ 7.56	$ 8.27	$ 8.74	$ 8.75	$ 8.66	2.0%
AECO (C$/mmbtu)	$ 6.51	$ 7.22	$ 7.69	$ 7.70	$ 7.61	2.3%
Huntingdon/Sumas (C$/mmbtu)	$ 6.51	$ 7.22	$ 7.69	$ 7.70	$ 7.61	2.3%

</TABLE>

5. LONG-TERM DEBT

	2007	2006
CANADIAN DOLLAR DENOMINATED DEBT		
Bank credit facilities		
Bankers' acceptances	$ 4,696	$ 6,621
Medium-term notes		
7.40% unsecured debentures repaid March 1, 2007	-	125
5.50% unsecured debentures due December 17, 2010	400	-
4.50% unsecured debentures due January 23, 2013	400	400
4.95% unsecured debentures due June 1, 2015	400	400
	5,896	7,546
US DOLLAR DENOMINATED DEBT		
Senior unsecured notes		
Adjustable rate due May 27, 2009 (2007 - US$62 million, 2006 - US$93 million)	61	108
US dollar debt securities		
7.80% due July 2, 2008 (2007 - US$8 million, 2006 - US$8 million)	8	9
6.70% due July 15, 2011 (2007 - US$400 million, 2006 - US$400 million)	395	466
5.45% due October 1, 2012 (2007 - US$350 million, 2006 - US$350 million)	346	408
4.90% due December 1, 2014 (2007 - US$350 million, 2006 - US$350 million)	346	408
6.00% due August 15, 2016 (2007 - US$250 million, 2006 - US$250 million)	247	291
5.70% due May 15, 2017 (2007 - US$1,100 million, 2006 - US$nil)	1,087	-
7.20% due January 15, 2032 (2007 - US$400 million, 2006 - US$400 million)	395	466
6.45% due June 30, 2033 (2007 - US$350 million, 2006 - US$350 million)	346	408
5.85% due February 1, 2035 (2007 - US$350 million, 2006 - US$350 million)	346	408
6.50% due February 15, 2037 (2007 - US$450 million, 2006 - US$450 million)	445	525
6.25% due March 15, 2038 (2007 - US$1,100 million, 2006 - US$nil)	1,087	-
Less - original issue discount on senior unsecured notes and US dollar debt securities (1)	(23)	-
	5,086	3,497
Change in fair value of interest rate swaps on US dollar debt securities (2)	9	-
	5,095	3,497
Long-term debt before transaction costs	10,991	11,043
Less - transaction costs (1) (3)	(51)	-
	$ 10,940	$ 11,043

(1) EFFECTIVE JANUARY 1, 2007, THE COMPANY HAS INCLUDED UNAMORTIZED ORIGINAL ISSUE DISCOUNTS AND DIRECTLY ATTRIBUTABLE TRANSACTION COSTS IN THE CARRYING VALUE OF THE OUTSTANDING DEBT.
(2) THE CARRYING VALUES 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 $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, 2007, the Company had in place unsecured bank credit facilities of $6,209 million, comprised of:

- a $100 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 would be repayable on the maturity date.

In conjunction with the closing of the acquisition of Anadarko Canada Corporation ("ACC") in November 2006 (note 15), 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.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2007, was 5.2% (2006 - 4.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $345 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2007.

MEDIUM-TERM NOTES

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. After issuing these securities, 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.

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

In 2006, the Company issued $400 million of debt securities maturing January 2013, bearing interest at 4.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

SENIOR UNSECURED NOTES

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

US DOLLAR DEBT SECURITIES

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 12). 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 12). Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

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 statement of earnings.

In 2006, the Company issued US$250 million of unsecured notes maturing August 2016 and US$450 million of unsecured notes maturing February 2037, bearing interest at 6.00% and 6.50%, respectively. Concurrently, the Company entered into cross currency swaps to fix the Canadian dollar interest and principal repayment amounts on the US$250 million notes at 5.40% and C$279 million (note 12). Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

In September 2007, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until October 2009.

Subsequent to December 31, 2007, the Company issued US$1,200 million of unsecured notes under this 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. If issued, these securities will bear interest as determined at the date of issuance.

REQUIRED DEBT REPAYMENTS
Required debt repayments are as follows:

Year	Repayment
2008	$ 39
2009	$ 2,361
2010	$ 400
2011	$ 395
2012	$ 346
Thereafter	$ 5,098

No debt repayments are reflected for $2,366 million of revolving bank credit facilities due to the extendable nature of the facilities.

6. OTHER LONG-TERM LIABILITIES

	2007	2006
Asset retirement obligations	$ 1,074	$ 1,166
Stock-based compensation	529	744
Risk management (note 12)	1,474	-
Other	101	94
	3,178	2,004
Less: current portion	1,617	611
	$ 1,561	$ 1,393

ASSET RETIREMENT OBLIGATIONS
At December 31, 2007, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $4,426 million (2006 - - $4,497 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 6.6% (2006 - 6.7%; 2005 - 6.8%). A reconciliation of the discounted asset retirement obligations is as follows:

	2007	2006	2005
Asset retirement obligations			
Balance - beginning of year	$ 1,166	$ 1,112	$ 1,119
Liabilities incurred	21	26	47
Liabilities (disposed) acquired (note 15)	(65)	56	-
Liabilities settled	(71)	(75)	(46)
Asset retirement obligation accretion	70	68	69
Revision of estimates	35	(21)	(56)
Foreign exchange	(82)	-	(21)
Balance - end of year	$ 1,074	$ 1,166	$ 1,112

STOCK-BASED COMPENSATION
The Company recognizes a liability for the 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.

<TABLE>
<CAPTION>

	2007	2006	2005
<S>	<C>	<C>	<C>
Stock-based compensation			
Balance - beginning of year	$ 744	$ 891	$ 323
Stock-based compensation	193	139	723
Cash payment for options surrendered	(375)	(264)	(227)
Transferred to common shares	(91)	(101)	(29)
Capitalized to Horizon Project	58	79	101
Balance - end of year	529	744	891
Less: current portion of stock-based compensation	390	611	629
	$ 139	$ 133	$ 262

</TABLE>

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 5.5% (2006 - 5.0%) 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, 2007 was $32 million (2006 - $29 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, 2007, these plan assets had a fair value of $47 million (2006 - $54 million). The unregistered pension plan and other post-retirement benefits are unfunded and have a benefit obligation of $10 million at December 31, 2007 (2006 - $15 million).

8. TAXES

TAXES OTHER THAN INCOME TAX

<TABLE>
<CAPTION>

	2007	2006	2005
<S>	<C>	<C>	<C>
Current petroleum revenue tax expense	$ 97	$ 196	$ 181
Deferred petroleum revenue tax expense (recovery)	44	37	(9)
Provincial capital taxes and surcharges	24	23	22
	$ 165	$ 256	$ 194

</TABLE>

INCOME TAX
The provision for income tax is as follows:

<TABLE>
<CAPTION>

	2007	2006	2005
<S>	<C>	<C>	<C>
Current income tax - North America	$ 96	$ 143	$ 99
Current income tax - North Sea	210	30	155
Current income tax - Offshore West Africa	74	49	32
Current income tax expense	380	222	286
Future income tax (recovery) expense	(456)	652	353
Income tax (recovery) expense	$ (76)	$ 874	$ 639

</TABLE>

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:

<TABLE>
<CAPTION>

	2007	2006	2005
<S>	<C>	<C>	<C>
Canadian statutory income tax rate	32.5%	34.9%	38.0%
Income tax provision at statutory rate	$ 877	$ 1,275	$ 716
Effect on income taxes of:			
Non-deductible portion of Canadian crown payments	-	131	309
Canadian resource allowance	-	(129)	(293)
Deductible UK petroleum revenue tax	(71)	(82)	(65)
Foreign tax rate differentials	79	92	(1)
North America income tax rate and other legislative changes	(864)	(438)	(19)
UK income tax rate changes	-	110	-
Cote d'Ivoire income tax rate changes	-	(67)	-
Non-taxable portion of foreign exchange (gain) loss	(96)	5	(15)
Other	(1)	(23)	7
Income tax (recovery) expense	$ (76)	$ 874	$ 639

</TABLE>

The following table summarizes the temporary differences that give rise to the net future income tax asset and liability:

<TABLE>
<CAPTION>

	2007	2006
<S>	<C>	<C>
Future income tax liabilities		
Property, plant and equipment	$ 5,695	$ 6,088
Timing of partnership items	1,288	1,394
Unrealized foreign exchange gain on long-term debt	199	93
Unrealized risk management activities	-	40
Other	55	13
Future income tax assets		
Asset retirement obligations	(380)	(487)
Loss carryforwards for income tax	(104)	(85)
Stock-based compensation	(125)	(232)
Unrealized risk management activities	(399)	-
Deferred petroleum revenue tax	20	(24)
Net future income tax liability	6,249	6,800
Less: current portion future income tax asset	(480)	(163)
Future income tax liability	$ 6,729	$ 6,963

</TABLE>

During 2007, enacted or substantively enacted income tax rate and other legislative changes resulted in a reduction of future income tax liabilities of approximately $864 million in North America. As a result of the enacted income tax rate changes, the Canadian federal corporate income tax rate will be reduced over the next five years from 21% in 2007 to 15% in 2012.

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 2005, enacted income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million in North America.

During 2003, the Canadian Federal Government enacted legislation to change the taxation of resource income. The legislation reduced the corporate income tax rate on resource income from 28% to 21% over five years beginning January 1, 2003. Over the same period, the deduction for resource allowance was phased out and a deduction for actual crown royalties paid was phased in. As a result, in 2007 crown royalties were fully deductible and the Company is no longer eligible for the resource allowance.

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.

<TABLE>
<CAPTION>

ISSUED	2007		2006	
NUMBER OF SHARES COMMON SHARES	Number of shares (THOUSANDS)	AMOUNT	Number of shares (thousands)	Amount
<S>	<C>	<C>	<C>	<C>
Balance - beginning of year	537,903	$ 2,562	536,348	$ 2,442
Issued upon exercise of stock options	1,826	21	2,040	21
Previously recognized liability on stock options exercised for common shares	-	91	-	101
Purchase of common shares under Normal Course Issuer Bid	-	-	(485)	(2)
Balance - end of year	539,729	$ 2,674	537,903	$ 2,562

</TABLE>

NORMAL COURSE ISSUER BID
During 2007, the Company did not purchase any common shares for cancellation pursuant to the Normal Course Issuer Bid previously filed, for the 12-month period beginning January 24, 2007 and ending on January 23, 2008 (2006 - 485,000 common shares were purchased at an average price of $57.33 per common share for a total cost of $28 million, 2005 - 850,000 common shares were purchased at an average price of $53.29 per common share for a total cost of $45 million). The Company has not renewed the Normal Course Issuer Bid in 2008.

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 February 2008, the Board of Directors set the Company's regular quarterly dividend at $0.10 per common share (2007 - $0.085 per common share, 2006 - $0.075 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 equally 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, 2007 and 2006:

<TABLE>
<CAPTION>

2007		2006	
STOCK OPTIONS (thousands)	WEIGHTED AVERAGE EXERCISE PRICE	Stock options (thousands)	Weighted average exercise price
<S>	<C>	<C>	<C>
Outstanding - beginning of year	34,431	$ 33.77	30,510	$ 17.79
Granted	7,502	$ 70.03	13,090	$ 59.61
Surrendered for cash settlement	(7,249)	$ 16.10	(5,180)	$ 12.60
Exercised for common shares	(1,826)	$ 11.71	(2,040)	$ 10.67
Forfeited	(2,199)	$ 46.46	(1,949)	$ 37.51
Outstanding - end of year	30,659	$ 47.23	34,431	$ 33.77
Exercisable - end of year	7,640	$ 30.00	9,177	$ 14.73

</TABLE>

The range of exercise prices of stock options outstanding and exercisable at December 31, 2007 were as follows:

<TABLE>
<CAPTION>

STOCK OPTIONS OUTSTANDING				STOCK OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICES	STOCK OPTIONS OUTSTANDING (thousands)	WEIGHTED AVERAGE REMAINING TERM (years)	WEIGHTED AVERAGE EXERCISE PRICE	STOCK OPTIONS EXERCISABLE (thousands)	WEIGHTED AVERAGE EXERCISE PRICE
<C>	<C>	<C>	<C>	<C>	<C>
$9.63 - $9.99	935	0.06	$ 9.63	935	$ 9.63
$10.00 - $19.99	5,510	1.38	$ 15.50	2,886	$ 14.66
$20.00 - $29.99	3,946	2.32	$ 25.47	1,187	$ 25.25
$30.00 - $39.99	1,012	2.72	$ 33.25	278	$ 33.28
$40.00 - $49.99	573	4.06	$ 46.79	133	$ 45.87
$50.00 - $59.99	5,980	3.76	$ 57.99	1,168	$ 57.81
$60.00 - $69.99	5,762	4.16	$ 61.59	1,053	$ 61.75
$70.00 - $73.35	6,941	5.16	$ 70.72	-	$ -
30,659	3.40	$ 47.23	7,640	$ 30.00	

</TABLE>

10. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The components of accumulated other comprehensive income (loss), net of taxes, were as follows:

<TABLE>
<CAPTION>

2007	2006
<S>	<C>	<C>
Derivative financial instruments designated as cash flow hedges	$ 101	$ -
Foreign currency translation adjustment	(29)	(13)
$ 72	$ (13)	

</TABLE>

During the next 12 months, $22 million is expected to be reclassified to net earnings from accumulated other comprehensive income.

11. NET EARNINGS PER COMMON SHARE

The following table provides a reconciliation between basic and diluted amounts per common share:

<TABLE>
<CAPTION>

(thousands of shares)	2007	2006	2005
<S>	<C>	<C>	<C>
Weighted average common shares outstanding - basic	539,336	537,339	536,650
Assumed settlement of preferred securities with common shares (1)	-	-	1,775
Weighted average common shares outstanding - diluted	539,336	537,339	538,425
Net earnings	$ 2,608	$ 2,524	$ 1,050
Interest on preferred securities, net of taxes(1)	-	-	4
Revaluation of preferred securities, net of taxes(1)	-	-	(2)
Diluted net earnings	$ 2,608	$ 2,524	$ 1,052
Net earnings per common share			
Basic	$ 4.84	$ 4.70	$ 1.96
Diluted	$ 4.84	$ 4.70	$ 1.95

</TABLE>
(1) THE PREFERRED SECURITIES WERE REDEEMED IN SEPTEMBER 2005.

12. FINANCIAL INSTRUMENTS

RISK MANAGEMENT
The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These derivative financial instruments are entered into solely for hedging purposes and are not intended for trading or other speculative purposes.

Commencing January 1, 2007, the Company recorded all of its derivative financial instruments on the balance sheet at fair value, including those designated as hedges. As at December 31, 2006, the net unrecognized asset related to the estimated fair values of derivative financial instruments designated as hedges was $222 million.

The estimated fair values of derivative financial instruments recognized in the risk management asset (liability) were comprised as follows:

<TABLE>
<CAPTION>

2007	2006	
RISK MANAGEMENT ASSET (LIABILITY)	Risk management MARK-TO-MARKET	Deferred mark-to-market revenue
<S>	<C>	<C>
Balance - beginning of year	$ 128	$ (877)
Retained earnings effect of adoption of financial instruments standards (note 2)	14	-
Net cost of outstanding put options	58	455
Net change in fair value of outstanding derivative financial instruments attributable to:		
- Risk management activities	(1,400)	1,005
- Interest expense	9	-
- Foreign exchange	(350)	-
- Other comprehensive income	125	-
Amortization of deferred revenue	-	-
	(1,416)	583
Add: put premium financing obligations (1)	(58)	(455)
Balance - end of year	(1,474)	128
Less: current portion	(1,227)	88
	$ (247)	$ 40

2006	
Risk management	Deferred revenue
<C>	<C>
$ (8)	
-	-
-	-
-	-
-	-
-	-
-	-
-	-
8	-
	-
-	-
-	-
-	-

</TABLE>
(1) THE COMPANY HAS NEGOTIATED PAYMENT OF PUT OPTION PREMIUMS WITH VARIOUS COUNTER-PARTIES AT THE TIME OF ACTUAL SETTLEMENT OF THE RESPECTIVE OPTIONS. THESE OBLIGATIONS HAVE BEEN REFLECTED IN THE NET RISK MANAGEMENT ASSET (LIABILITY).

Net losses (gains) from risk management activities for the years ended December 31 were as follows:

	2007	2006	2005
Net realized risk management loss	$ 162	$ 1,325	$ 1,027
Net unrealized risk management loss (gain)	1,400	(1,013)	925
	$ 1,562	$ 312	$ 1,952

FINANCIAL CONTRACTS

The Company's financial instruments recognized in the consolidated balance sheets consist of cash and cash equivalents, accounts receivable, accounts payable, accrued liabilities, risk management activities, and long-term debt. The carrying value of these financial instruments approximates their fair value, except as noted below.

	2007		2006	
(LIABILITY) ASSET	CARRYING VALUE	FAIR VALUE	Carrying value	Fair value
Derivative financial instruments	$ (1,416)	$ (1,416)	$ 583	$ 805
Fixed rate notes	$ (6,318)	$ (6,259)	$ (4,410)	$ (4,434)

The estimated fair values of these financial instruments have been determined based on the Company's assessment of available market information, appropriate internal valuation methodologies and/or third party indications. However, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and the differences may be material.

COMMODITY PRICE RISK MANAGEMENT

As at December 31, 2007, the Company had the following net financial derivatives outstanding to manage its commodity price exposures:

REMAINING TERM	VOLUME	WEIGHTED AVERAGE PRICE	INDEX
CRUDE OIL			
Crude oil price collars (1)	Jan 2008 - Mar 2008	50,000 bbl/d	US$60.00 - US$80.06 WTI
Jan 2008 - Jun 2008	25,000 bbl/d	US$60.00 - US$80.44	WTI
Apr 2008 - Sep 2008	25,000 bbl/d	US$60.00 - US$80.46	WTI
Jul 2008 - Sep 2008	25,000 bbl/d	US$70.00 - US$123.75	WTI
Oct 2008 - Dec 2008	25,000 bbl/d	US$70.00 - US$112.63	WTI
Jan 2008 - Dec 2008	20,000 bbl/d	US$50.00 - US$65.53	Mayan Heavy
Jan 2008 - Dec 2008	50,000 bbl/d	US$60.00 - US$75.22	WTI
Jan 2008 - Dec 2008	50,000 bbl/d	US$60.00 - US$76.05	WTI
Jan 2008 - Dec 2008	50,000 bbl/d	US$60.00 - US$76.98	WTI
Crude oil puts	Jan 2008 - Dec 2008	50,000 bbl/d	US$55.00 WTI

(1) SUBSEQUENT TO DECEMBER 31, 2007, THE COMPANY ENTERED INTO 25,000 BBL/D OF US$70.00 - US$111.56 WTI COLLARS FOR THE PERIOD JANUARY TO DECEMBER 2009.

The cost of outstanding put options of US$59 million will be settled in 2008.

REMAINING TERM	VOLUME	WEIGHTED AVERAGE PRICE	INDEX
NATURAL GAS			
AECO price collars	Jan 2008 - Mar 2008	400,000 GJ/d	C$7.00 - C$14.08 AECO
Jan 2008 - Mar 2008	500,000 GJ/d	C$7.50 - C$10.81	AECO

Commodity related derivative financial instruments designated as hedges at December 31, 2007, were all classified as cash flow hedges.

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

As at December 31, 2007, the net pre-tax unrealized loss related to the de-designation of commodity cash flow hedges was $15 million (2006 - $41

million). This unrealized loss will be recognized in net earnings in 2008.

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 agreements 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, 2007, the Company had the following interest rate swap contracts outstanding:

<TABLE>
<CAPTION>

REMAINING TERM	AMOUNT ($ millions)	FIXED RATE	FLOATING RATE
<S>	<C>	<C>	<C>
INTEREST RATE			
Swaps - fixed to floating	Jan 2008 - Oct 2012	US$350	5.45% LIBOR (1) + 0.81%
Jan 2008 - Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%

</TABLE>

(1) LONDON INTERBANK OFFERED RATE

All interest rate related derivative financial instruments designated as hedges at December 31, 2007, were classified as fair value hedges.

FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

The Company is exposed to foreign exchange rate risk in Canada on its US dollar denominated debt and on product sales based on US dollar denominated benchmarks. The Company is also exposed to foreign exchange rate risk on transactions conducted in foreign currencies in its foreign subsidiaries and in the carrying value of its self-sustaining foreign subsidiaries. The Company enters into cross currency swap agreements 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. The Company may also enter into foreign currency denominated financial contracts to manage future US dollar denominated crude oil and natural gas sales. At December 31, 2007, the Company had the following cross currency swap contracts outstanding:

<TABLE>
<CAPTION>

REMAINING TERM	AMOUNT ($ millions)	EXCHANGE RATE (US$/C$)	INTEREST RATE (US$)	INTEREST RATE (C$)
<S>	<C>	<C>	<C>	<C>
CURRENCY				
Swaps	Jan 2008 - Aug 2016	US$250	1.116	6.00% 5.40%
Jan 2008 - May 2017	US$1,100	1.170	5.70%	5.10%
Jan 2008 - Mar 2038	US$550	1.170	6.25%	5.76%

</TABLE>

All cross currency related derivative financial instruments designated as hedges at December 31, 2007, were classified as cash flow hedges.

COUNTERPARTY CREDIT RISK MANAGEMENT

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.

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 substantially all investment grade financial institutions and other entities. At December 31, 2007, the Company had net risk management assets of $20 million (December 31, 2006 - $161 million) with specific counterparties related to derivative financial instruments.

13. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

<TABLE>
<CAPTION>

2008	2009	2010	2011	2012	Thereafter
<S>	<C>	<C>	<C>	<C>	<C>
Product transportation and pipeline	$ 232	$ 151	$ 137	$ 109	$ 91	$ 972
Offshore equipment operating lease (1)	$ 114	$ 129	$ 113	$ 111	$ 90	$ 387
Offshore drilling (2) (3)	$ 267	$ 185	$ 39	$ -	$ -	$ -
Asset retirement obligations (4)	$ 33	$ 4	$ 5	$ 4	$ 4	$ 4,376
Office leases	$ 26	$ 28	$ 28	$ 22	$ 3	$ -
Electricity and other	$ 166	$ 173	$ 25	$ 4	$ -	$ -

</TABLE>

(1) OFFSHORE EQUIPMENT OPERATING LEASES ARE PRIMARILY COMPRISED OF OBLIGATIONS RELATED TO FLOATING PRODUCTION, STORAGE AND OFFTAKE VESSELS ("FPSO"). DURING 2006, THE COMPANY ENTERED INTO AN AGREEMENT TO LEASE AN ADDITIONAL FPSO COMMENCING IN 2008, IN CONNECTION WITH THE PLANNED OFFSHORE DEVELOPMENT IN GABON, OFFSHORE WEST AFRICA. DURING THE INITIAL TERM, THE TOTAL ANNUAL PAYMENTS FOR THE GABON FPSO ARE ESTIMATED TO BE US$50 MILLION.

(2) DURING 2007, THE COMPANY ENTERED INTO A ONE-YEAR AGREEMENT FOR OFFSHORE DRILLING SERVICES RELATED TO THE BAOBAB FIELD IN COTE D'IVOIRE, OFFSHORE WEST AFRICA. THE AGREEMENT IS SCHEDULED TO COMMENCE IN 2008, SUBJECT TO RIG AVAILABILITY. ESTIMATED TOTAL PAYMENTS OF US$100 MILLION, AFTER JOINT VENTURE RECOVERIES, HAVE BEEN INCLUDED IN THIS TABLE FOR THE PERIOD 2008-2009.

(3) DURING 2007, THE COMPANY AWARDED CONTRACTS FOR A DRILLING RIG AND FOR THE CONSTRUCTION OF WELLHEAD TOWERS IN CONNECTION WITH THE PLANNED OFFSHORE DEVELOPMENT IN GABON, OFFSHORE WEST AFRICA. ESTIMATED TOTAL PAYMENTS OF US$393 MILLION HAVE BEEN INCLUDED IN THIS TABLE FOR THE PERIOD 2008-2010.

(4) 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 2008 - 2012 REPRESENT THE MINIMUM REQUIRED EXPENDITURES TO MEET THESE OBLIGATIONS. ACTUAL EXPENDITURES IN ANY PARTICULAR YEAR MAY EXCEED THESE MINIMUM AMOUNTS.

In addition to the amounts disclosed above, the Company has budgeted construction costs of approximately $1.7 billion to $1.9 billion for 2008 related to the planned completion of Phase 1 of the Horizon Project.

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.

14. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Changes in non-cash working capital were as follows:

<TABLE>
<CAPTION>

2007	2006	2005
<S>	<C>	<C>	<C>
(Increase) decrease in non-cash working capital			
Accounts receivable and other	$ 334	$ (116)	$ (498)
Accounts payable	(456)	157	196
Accrued liabilities	(402)	(582)	716
Net change in non-cash working capital	$ (524)	$ (541)	$ 414
Relating to:			
Operating activities	$ (346)	$ (679)	$ (147)
Financing activities	8	37	19
Investing activities	(186)	101	542
$ (524)	$ (541)	$ 414	

<CAPTION>

Other cash flow information:	2007	2006	2005
<S>	<C>	<C>	<C>
Interest paid	$ 556	$ 262	$ 200
Taxes paid	$ 418	$ 703	$ 430

</TABLE>

15. 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:

November 2, 2006	
Net purchase price:	
Net cash consideration (1)	$ 4,641
Net purchase price allocated as follows:	
Non-cash working capital deficit assumed and other	$ (105)
Property, plant and equipment	6,249
Long-term debt	(9)
Asset retirement obligation	(56)
Future income tax	(1,438)
	$ 4,641

(1) NET CASH CONSIDERATION WAS REDUCED BY $88 MILLION TO REFLECT THE SETTLEMENT OF US DOLLAR CURRENCY FORWARD CONTRACTS DESIGNATED AS HEDGES OF THE ACC PURCHASE PRICE.

16. 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 relate to 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 included in the segmented information as other.

Inter-segment eliminations include internal transportation and electricity charges.

<TABLE>
<CAPTION>
CONVENTIONAL CRUDE OIL AND NATURAL GAS

	NORTH AMERICA			NORTH SEA			OFFSHORE WEST AFRICA		
	2007	2006	2005	2007	2006	2005	2007	2006	2005
SEGMENTED REVENUE	$ 10,149	$ 9,066	$ 8,955	$ 1,597	$ 1,616	$ 1,659	$ 776	$ 950	$ 485
Less: royalties	(1,318)	(1,203)	(1,350)	(3)	(3)	(3)	(70)	(39)	(13)
REVENUE, NET OF ROYALTIES	8,831	7,863	7,605	1,594	1,613	1,656	706	911	472
SEGMENTED EXPENSES									
Production	1,642	1,436	1,211	432	390	379	94	106	53
Transportation and blending	1,595	1,465	1,310	16	15	20	1	1	-
Depletion, depreciation and amortization	2,350	1,897	1,595	340	297	306	165	189	104
Asset retirement obligation accretion	38	35	34	30	31	34	2	2	1
Realized risk management activities	129	1,022	870	33	303	157	-	-	-
TOTAL SEGMENTED EXPENSES	5,754	5,855	5,020	851	1,036	896	262	298	158
SEGMENTED EARNINGS BEFORE THE FOLLOWING	$ 3,077	$ 2,008	$ 2,585	$ 743	$ 577	$ 760	$ 444	$ 613	$ 314
NON-SEGMENTED EXPENSES									
Administration									
Stock-based compensation									
Interest, net									
Unrealized risk management activities									
Foreign exchange (gain) loss									
TOTAL NON-SEGMENTED EXPENSES									
EARNINGS BEFORE TAXES									
Taxes other than income tax									
Current income tax expense									
Future income tax (recovery) expense									
NET EARNINGS									

</TABLE>

<TABLE>
<CAPTION>

	MIDSTREAM			INTER-SEGMENT ELIMINATION AND OTHER			TOTAL		
	2007	2006	2005	2007	2006	2005	2007	2006	2005
SEGMENTED REVENUE	$ 74	$ 72	$ 77	$ (53)	$ (61)	$ (46)	$ 12,543	$ 11,643	$ 11,130
Less: royalties	-	-	-	-	-	-	(1,391)	(1,245)	(1,366)
REVENUE, NET OF ROYALTIES	74	72	77	(53)	(61)	(46)	11,152	10,398	9,764
SEGMENTED EXPENSES									
Production	22	23	24	(6)	(6)	(4)	2,184	1,949	1,663
Transportation and blending	-	-	-	(42)	(38)	(37)	1,570	1,443	1,293
Depletion, depreciation and amortization	8	8	8	-	-	-	2,863	2,391	2,013
Asset retirement obligation accretion	-	-	-	-	-	-	70	68	69
Realized risk management activities	-	-	-	-	-	-	162	1,325	1,027
TOTAL SEGMENTED EXPENSES	30	31	32	(48)	(44)	(41)	6,849	7,176	6,065
SEGMENTED EARNINGS BEFORE THE FOLLOWING	$ 44	$ 41	$ 45	$ (5)	$ (17)	$ (5)	$ 4,303	$ 3,222	$ 3,699
NON-SEGMENTED EXPENSES									
Administration							208	180	151
Stock-based compensation							193	139	723
Interest, net							276	140	149
Unrealized risk management activities							1,400	(1,013)	925
Foreign exchange (gain) loss							(471)	122	(132)
TOTAL NON-SEGMENTED EXPENSES							1,606	(432)	1,816
EARNINGS BEFORE TAXES							2,697	3,654	1,883
Taxes other than income tax							165	256	194
Current income tax expense							380	222	286
Future income tax (recovery) expense							(456)	652	353
NET EARNINGS							$ 2,608	$ 2,524	$ 1,050

<CAPTION>
CAPITAL EXPENDITURES

	2007			2006		
	NET EXPENDITURES	NON CASH/FAIR VALUE CHANGES(1)	CAPITALIZED COSTS	Net expenditures	Non cash/fair value changes(1)	Capitalized costs
Conventional crude oil and natural gas						
North America	$ 2,428	$ 52	$ 2,480	$ 7,936	$ 1,521	$ 9,457
North Sea	439	(77)	362	646	(14)	632
Offshore West Africa	159	(11)	148	134	1	135
Other	1	-	1	11	-	11
	3,027	(36)	2,991	8,727	1,508	10,235
Horizon Project (2)	3,301	-	3,301	3,185	-	3,185
Midstream	6	-	6	12	-	12
Head office	20	-	20	26	-	26
	$ 6,354	$ (36)	$ 6,318	$ 11,950	$ 1,508	$ 13,458

</TABLE>
(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 AND STOCK-BASED COMPENSATION.

<TABLE>
<CAPTION>
SEGMENTED ASSETS

2007	2006
<S>	<C> <C>
Conventional crude oil and natural gas	
North America	$ 23,617 $ 23,670
North Sea	1,957 2,248
Offshore West Africa	1,354 1,323
Other	41 46
Horizon Project	8,740 5,444
Midstream	333 355
Head office	72 74
$ 36,114	$ 33,160

</TABLE>

17. 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 as reported:

<TABLE>
<CAPTION>

(millions of Canadian dollars, except per common share amounts)	Notes	2007	2006	2005
<S>	<C>	<C>	<C>	<C>
Net earnings - Canadian GAAP		$ 2,608	$ 2,524	$ 1,050
Adjustments				
Depletion, net of taxes of $1 million (2006 - $1 million, 2005 - $3 million)	(A,D)	(10)	2	4
Stock-based compensation, net of taxes of $3 million (2006 - $18 million, 2005 - $nil)	(B)	(22)	(40)	-
Future income taxes	(H)	(234)	-	-
Derivative financial instruments and hedging activities, net of taxes of $nil (2006 - $15 million, 2005 - $11 million)	(C,D)	-	117	(19)
Net earnings before cumulative effect of change in accounting policy - US GAAP		2,342	2,603	1,035
Cumulative effect of change in accounting policy, net of taxes of $nil (2006 - $3 million, 2005 - $nil)	(B)	-	(8)	-
Net earnings - US GAAP		$ 2,342	$ 2,595	$ 1,035
Net earnings before cumulative effect of change in accounting policy - US GAAP per common share				
Basic		$ 4.34	$ 4.84	$ 1.93
Diluted	(F)	$ 4.32	$ 4.77	$ 1.88
Net earnings - US GAAP per common share				
Basic		$ 4.34	$ 4.83	$ 1.93
Diluted	(F)	$ 4.32	$ 4.75	$ 1.88

<CAPTION>
Comprehensive income under US GAAP would be as follows:

(millions of Canadian dollars)	Notes	2007	2006	2005
<S>	<C>	<C>	<C>	<C>
Comprehensive income - Canadian GAAP		$ 2,534	$ 2,520	$ 1,047
US GAAP earnings adjustments		(266)	71	(15)
Derivative financial instruments and hedging activities, net of taxes of $nil (2006 - $394 million; 2005 - $312 million)	(C,D)	-	805	(635)
Comprehensive income - US GAAP		$ 2,268	$ 3,396	$ 397

</TABLE>

The components of accumulated other comprehensive income under US GAAP, net of taxes, would be as follows:

	2007	2006
Derivative financial instruments designated as cash flow hedges	101	159
Foreign currency translation adjustment	(29)	(13)
Accumulated other comprehensive income	72	146

The application of US GAAP would have the following effects on the consolidated balance sheets as reported:

2007 (millions of Canadian dollars)	Notes	CANADIAN GAAP	INCREASE (DECREASE)	US GAAP
Current assets		2,181	-	2,181
Property, plant and equipment	(A,B,D,E)	33,902	91	33,993
Other long-term assets	(I)	31	51	82
		36,114	142	36,256
Current liabilities	(B)	3,563	66	3,629
Long-term debt	(I)	10,940	51	10,991
Other long-term liabilities	(B)	1,561	20	1,581
Future income tax	(A,B,D,E,H)	6,729	236	6,965
Share capital		2,674	-	2,674
Retained earnings		10,575	(231)	10,344
Accumulated other comprehensive income		72	-	72
		36,114	142	36,256

2006 (millions of Canadian dollars)	Notes	Canadian GAAP	Increase (Decrease)	US GAAP
Current assets	(C)	2,239	131	2,370
Property, plant and equipment	(A,B,D,E)	30,767	89	30,856
Other long-term assets	(C)	154	29	183
		33,160	249	33,409
Current liabilities	(B)	3,071	30	3,101
Long-term debt	(C)	11,043	(26)	11,017
Other long-term liabilities	(B)	1,393	20	1,413
Future income tax	(A,B,C,D,E)	6,963	21	6,984
Share capital		2,562	-	2,562
Retained earnings		8,141	45	8,186
Accumulated other comprehensive (loss) income	(C)	(13)	159	146
		33,160	249	33,409

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"). 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 prior years resulted in the recognition of a ceiling test impairment under US GAAP, decreasing property, plant and equipment.

For the year ended December 31, 2007, US GAAP net earnings would have decreased by $4 million (2006 - increased by $3 million, 2005 - increased by $4 million), net of income taxes of $8 million (2006 - $2 million, 2005 - $3 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, 2007, US GAAP net earnings would have decreased by $22 million (2006 - $48 million), net of income taxes of $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. There was no difference from Canadian GAAP prior to 2006.

(C) Effective January 1, 2007, the Company adopted new accounting standards for financial instruments as described in note 2. 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, for the year ended December 31, 2006, assets would have increased by $160 million, liabilities would have decreased by $9 million, and accumulated other comprehensive income would have increased by $159 million as a result of recording all derivative financial instruments at fair value in accordance with US GAAP.

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 (2005 - loss of $19 million, net of income taxes of $11 million).

(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, 2007, US GAAP net earnings would have been decreased by $6 million (2006 - $1 million), net of income taxes of $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, 2007, an additional 3,376,000 shares would have been included in the calculation of diluted earnings per share for US GAAP (2006 - 8,762,000 additional shares, 2005 - 13,593,000 additional shares).

(G) In July 2006, the FASB issued Interpretation ("FIN") No. 48 "Accounting for Uncertainty in Tax Positions - an Interpretation of FASB Statement No. 109", effective for fiscal years beginning after December 15, 2006. FIN 48 prescribes thresholds for recognizing the benefits of uncertain tax positions in the financial statements. It also provides guidance on derecognition, classification, interest and penalties, disclosure and transition. The adoption of this standard did not result in a reconciling item under US GAAP.

(H) 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 results in a difference in timing of the recognition of a $234 million future tax recovery.

(I) 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 $51 million of debt issue costs from long-term debt to deferred charges in 2007. There were no GAAP differences prior to 2007.

(J) US GAAP - RECENTLY ISSUED ACCOUNTING STANDARDS

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 Company is currently assessing the impact this standard has on its consolidated financial statements.

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 Company is currently assessing the impact this standard has on its consolidated financial statements.

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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

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 2008 guidance provided throughout this Management's Discussion and Analysis ("MD&A"), including the information provided in the "Outlook" section, constitutes forward-looking statements. 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.

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 assurance that the plans, initiatives or expectations upon which they are based will occur.

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 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. 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 interdependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available. For additional information refer to the "Risks and Uncertainties" section of this MD&A.

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 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 cash flow from operations, adjusted net earnings from operations and net asset value. These financial measures are not defined by Canadian 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.

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, 2007. The consolidated financial statements have been prepared in accordance with Canadian GAAP. A reconciliation of Canadian GAAP to United States GAAP is included in note 17 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 oil to estimate relative energy content. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the wellhead. Production volumes are the Company's interest before royalties, and realized prices exclude the effect of risk management activities and transportation and blending costs, except where otherwise noted. The following discussion and analysis refers primarily to the Company's 2007 financial results compared to 2006 and 2005, unless otherwise indicated. In addition, this MD&A details the Company's capital program and outlook for 2008.

Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2007 and its Annual Information Form for the year ended December 31, 2007, is available on SEDAR at www.sedar.com.

This MD&A is dated February 26, 2008.

ABBREVIATIONS

ACC	Anadarko Canada Corporation
AECO	Alberta natural gas reference location
API	Specific gravity measured in degrees on the American Petroleum Institute scale
ARO	Asset retirement obligations
BBL	barrel
BBL/D	barrels per day
BOE	barrels of oil equivalent
BOE/D	barrels of oil equivalent per day
BRENT	Dated Brent
C$	Canadian dollars
CO2	Carbon dioxide
CO2e	Carbon dioxide equivalents
CICA	Canadian Institute of Chartered Accountants
FPSO	Floating Production, Storage and Offtake Vessel
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
GJ	gigajoule
HEAVY DIFFERENTIAL	Heavy crude oil differential from WTI
HORIZON PROJECT	Horizon Oil Sands Project LLB Lloyd Blend
MCF	thousand cubic feet
MMBTU	million British thermal units
MMCF/D	million cubic feet per day
NGLS	Natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
SCO	Synthetic light crude oil
SEC	United States Securities and Exchange Commission
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US$	United States dollars
WTI	West Texas Intermediate

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 the 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:

o 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;

o Balance among near-, mid- and long-term projects;

o Balance among acquisitions, exploitation and exploration; and

o 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:

o Blending various crude oil streams with diluents to create more attractive feedstock;

o Supporting and participating in pipeline expansions and/or new additions; and

o Supporting and participating in projects that will increase the downstream conversion capacity for heavy crude oil.

Operational discipline and cost control are central to the Company. By consistently controlling costs throughout all cycles of the industry, the Company believes that 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 its strong financial position. The Company believes that it has built the necessary financial capacity to complete the Horizon Project while at the same time not compromising the delivery of its conventional crude oil and natural gas growth opportunities. Additionally, the Company's risk management hedge program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditures program throughout the Horizon Project construction period.

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, 2007 are as follows:

o Achieved record levels of net earnings, adjusted net earnings from operations and cash flow;

o Achieved record natural gas production;

o Achieved its annual production guidance for crude oil and NGLs and natural gas;

o Completed 90% of Phase 1 work progress of the Horizon Project; and

o Increased dividends per common share.

NET EARNINGS AND CASH FLOW FROM OPERATIONS

<TABLE>
<CAPTION>
FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	2007	2006	2005
<S>	<C>	<C>	<C>
Revenue, before royalties	$ 12,543	$ 11,643	$ 11,130
Net earnings	$ 2,608	$ 2,524	$ 1,050
Per common share - basic	$ 4.84	$ 4.70	$ 1.96
- diluted	$ 4.84	$ 4.70	$ 1.95
Adjusted net earnings from operations (1)	$ 2,406	$ 1,664	$ 2,034
Per common share - basic	$ 4.46	$ 3.10	$ 3.79
- diluted	$ 4.46	$ 3.10	$ 3.78
Cash flow from operations (2)	$ 6,198	$ 4,932	$ 5,021
Per common share - basic	$ 11.49	$ 9.18	$ 9.36
- diluted	$ 11.49	$ 9.18	$ 9.33
Dividends declared per common share	$ 0.34	$ 0.30	$ 0.236
Total assets	$ 36,114	$ 33,160	$ 21,852
Total long-term liabilities	$ 19,230	$ 19,399	$ 9,790
Capital expenditures, net of dispositions	$ 6,425	$ 12,025	$ 4,932

</TABLE>

(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" 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" 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.

<TABLE>
<CAPTION>
ADJUSTED NET EARNINGS FROM OPERATIONS

($ MILLIONS)	2007	2006	2005
<S>	<C>	<C>	<C>
NET EARNINGS AS REPORTED	$ 2,608	$ 2,524	$ 1,050
STOCK-BASED COMPENSATION EXPENSE, NET OF TAX (a)	134	95	481
UNREALIZED RISK MANAGEMENT LOSS (GAIN), NET OF TAX (b)	977	(674)	607
UNREALIZED FOREIGN EXCHANGE (GAIN) LOSS, NET OF TAX (c)	(449)	114	(85)
EFFECT OF STATUTORY TAX RATE AND OTHER LEGISLATIVE CHANGES ON FUTURE INCOME TAX LIABILITIES (d)	(864)	(395)	(19)
ADJUSTED NET EARNINGS FROM OPERATIONS	$ 2,406	$ 1,664	$ 2,034

</TABLE>

(a) THE COMPANY'S EMPLOYEE STOCK OPTION PLAN PROVIDES FOR A CASH PAYMENT OPTION. ACCORDINGLY, THE INTRINSIC VALUE OF THE 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 FLOWING THROUGH 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 SWAPS, AND ARE IMMEDIATELY RECOGNIZED IN NET EARNINGS.

(d) ALL SUBSTANTIVELY 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 CHANGES IS RECORDED IN NET EARNINGS DURING THE PERIOD THE LEGISLATION IS SUBSTANTIVELY ENACTED. 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 OFFSHORE WEST AFRICA. INCOME TAX RATE CHANGES DURING 2005 RESULTED IN A REDUCTION OF FUTURE INCOME TAX LIABILITIES OF APPROXIMATELY $19 MILLION IN NORTH AMERICA.

<TABLE>
<CAPTION>
CASH FLOW FROM OPERATIONS

($ MILLIONS)	2007	2006	2005
<S>	<C>	<C>	<C>
NET EARNINGS	$ 2,608	$ 2,524	$ 1,050
NON-CASH ITEMS:			
DEPLETION, DEPRECIATION AND AMORTIZATION	2,863	2,391	2,013
ASSET RETIREMENT OBLIGATION ACCRETION	70	68	69
STOCK-BASED COMPENSATION EXPENSE	193	139	723
UNREALIZED RISK MANAGEMENT LOSS (GAIN)	1,400	(1,013)	925
UNREALIZED FOREIGN EXCHANGE (GAIN) LOSS	(524)	134	(103)
DEFERRED PETROLEUM REVENUE TAX EXPENSE (RECOVERY)	44	37	(9)
FUTURE INCOME TAX (RECOVERY) EXPENSE	(456)	652	353
CASH FLOW FROM OPERATIONS	$ 6,198	$ 4,932	$ 5,021

</TABLE>

For 2007, the Company reported net earnings of $2,608 million compared to net earnings of $2,524 million for 2006 (2005 - $1,050 million). Net earnings for the year ended December 31, 2007 included net unrealized after-tax income of $202 million related to the effects of risk management activities, fluctuations in foreign exchange rates, stock-based compensation expense and the impact of statutory tax rate and other legislative changes on future income tax liabilities (2006 - net unrealized after-tax income of $860 million; 2005 - net unrealized after-tax expenses of $984 million). Excluding these items, adjusted net earnings from operations for the year ended December 31, 2007 increased to $2,406 million from $1,664 million for 2006 (2005 - $2,034 million) primarily due to higher realized pricing, lower realized risk management losses, higher North America crude oil and NGLs and natural gas sales volumes, and lower income tax expense. These factors were partially offset by higher production expense, higher depletion, depreciation and amortization expense, higher interest expense, and the impact of the stronger Canadian dollar relative to the US dollar.

The Company expects that consolidated net earnings will continue to reflect significant volatility due to the impact of risk management activities, stock-based compensation expense and fluctuations in foreign exchange rates.

The Company's commodity hedging program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditures throughout the Horizon Project construction period. This program allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 65% of budgeted crude oil volumes are hedged for 2008 and approximately 53% of budgeted natural gas volumes are hedged for the first quarter of 2008. Subsequent to December 31, 2007, the Company hedged 25,000 bbl/d of crude oil volumes for 2009 using WTI collars with a US$70.00 floor.

The Company's outstanding commodity related financial derivatives as at December 31, 2007 are detailed in the "Liquidity and Capital Resources" section of this MD&A.

As disclosed in note 2 to the Company's consolidated financial statements, commencing January 1, 2007 all derivative financial instruments are recognized at fair value on the consolidated balance sheet at each reporting date. As effective as the Company's hedges are against reference commodity prices, a substantial portion of the derivative financial instruments entered into by the Company have not been formally designated as hedges for accounting purposes or do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The change in the fair value of the 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 risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at December 31, 2007.

Due to the changes in crude oil and natural gas forward pricing and the reversal of prior-year unrealized gains and losses, the Company recorded a net unrealized loss of $1,400 million ($977 million after-tax) on its commodity risk management activities for the year ended December 31, 2007 (2006 - $1,013 million unrealized gain, $674 million after-tax; 2005 - $925 million unrealized loss, $607 million after-tax). Mark-to-market unrealized gains and losses do not impact the Company's current cash flow or its ability to finance ongoing capital programs. The Company continues to believe that its risk management program meets its objective of securing funding for its capital projects and does not intend to alter its current strategy of obtaining price certainty for its crude oil and natural gas sales. For further details, refer to the "Risk Management Activities" section of this MD&A.

The Company also recorded a $193 million ($134 million after-tax) stock-based compensation expense as a result of the 17% increase in the Company's share price for the year ended December 31, 2007 (Company's share price as at: December 31, 2007 - $72.58; December 31, 2006 - $62.15; December 31, 2005 - $57.63; December 31, 2004 - $25.63). As required by 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 the 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 as part of the Horizon Project during the construction period. The stock-based compensation liability at December 31, 2007 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, 2007. In years when substantial share price changes occur, the Company's net 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.

Cash flow from operations for the year ended December 31, 2007 increased to $6,198 million ($11.49 per common share) from $4,932 million ($9.18 per common share) for 2006 (2005 - $5,021 million; $9.36 per common share). The increase was primarily due to higher North America crude oil and NGLs and natural gas sales volumes, higher realized pricing, and lower realized risk management losses. These factors were partially offset by higher production expense, higher interest costs, higher current taxes, and the impact of the strengthening of the Canadian dollar relative to the US dollar.

For 2007, the Company's average sales price per bbl of crude oil and NGLs increased to $55.45 per bbl from $53.65 per bbl in 2006 (2005 - $46.86 per bbl). The Company's average natural gas price increased to $6.85 per mcf from $6.72 per mcf for 2006 (2005 - $8.57 per mcf).

Total production of crude oil and NGLs before royalties decreased marginally to 331,232 bbl/d from 331,998 bbl/d for 2006 (2005 - 313,168 bbl/d). The decrease in crude oil and NGLs production primarily reflected lower production in the North Sea due to the timing of planned maintenance activities and lower production from the Baobab Field in Offshore West Africa, offset by increased production in North America including increased production from the Company's Primrose thermal projects, the results from the Pelican Lake waterflood project, and the acquisition of ACC in 2006.

Total natural gas production before royalties increased to 1,668 mmcf/d from 1,492 mmcf/d for 2006 (2005 - 1,439 mmcf/d). The increase in natural gas production primarily reflected additional natural gas production from the ACC acquisition. The increase was partially offset by the production declines in 2007 due to the Company's strategic reduction in natural gas drilling activity.

Total crude oil and NGLs and natural gas production volumes before royalties increased to 609,206 boe/d from 580,724 boe/d for 2006 (2005 - 552,960 boe/d).

OPERATING HIGHLIGHTS

	2007	2006	2005
CRUDE OIL AND NGLS ($/BBL) (1)			
Sales price (2)	$ 55.45	$ 53.65	$ 46.86
Royalties	5.94	4.48	3.97
Production expense	13.34	12.29	11.17
Netback	$ 36.17	$ 36.88	$ 31.72
NATURAL GAS ($/MCF) (1)			
Sales price (2)	$ 6.85	$ 6.72	$ 8.57
Royalties	1.11	1.29	1.75
Production expense	0.91	0.82	0.73
Netback	$ 4.83	$ 4.61	$ 6.09
BARRELS OF OIL EQUIVALENT ($/BOE) (1)			
Sales price (2)	$ 49.05	$ 47.92	$ 48.77
Royalties	6.26	5.89	6.82
Production expense	9.75	9.14	8.21
Netback	$ 33.04	$ 32.89	$ 33.74

(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:

<TABLE>
($ millions, except per common share amounts)

2007	TOTAL	DEC 31	SEP 30	JUN 30	MAR 31
<S>	<C>	<C>	<C>	<C>	<C>
Revenue, before royalties	$12,543	$ 3,200	$ 3,073	$ 3,152	$ 3,118
Net earnings	$ 2,608	$ 798	$ 700	$ 841	$ 269
Net earnings per common share					
- basic and diluted	$ 4.84	$ 1.48	$ 1.30	$ 1.56	$ 0.50
-					

2006	Total	Dec 31	Sep 30	Jun 30	Mar 31
-					
Revenue, before royalties	$11,643	$ 2,826	$ 3,108	$ 3,041	$ 2,668
Net earnings	$ 2,524	$ 313	$ 1,116	$ 1,038	$ 57
Net earnings per common share					
- basic and diluted	$ 4.70	$ 0.58	$ 2.08	$ 1.93	$ 0.11

</TABLE>

The Company's quarterly consolidated revenues increased 20% to $3,200 million for the fourth quarter of 2007 from $2,668 million for the first quarter of 2006. Net earnings fluctuated from $57 million for the first quarter of 2006 to $798 million for the fourth quarter of 2007. Net earnings 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 financial instruments, higher depletion, depreciation and amortization charges, 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:

o Crude oil pricing

Crude oil prices reflected demand growth, continued geopolitical uncertainties and fluctuations in the Heavy Differential in North America. The Company's realized crude oil and NGLs price increased to $58.03 per bbl for the fourth quarter of 2007 from $43.79 per bbl for the first quarter of 2006. The Heavy Differential averaged 38% for the fourth quarter of 2007 compared to 45% for the first quarter of 2006.

o Natural gas pricing

Natural gas prices primarily reflected fluctuations in demand for natural gas and high inventory storage levels as a result of seasonality, milder overall weather experienced during 2007 and 2006, and increased liquefied natural gas imports into the US during the first half of 2007. The Company's realized natural gas price decreased to $6.28 per mcf for the fourth quarter of 2007 from $8.30 per mcf for the first quarter of 2006.

o 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, development of West and East Espoir, and additional sales volumes from the ACC acquisition completed in the fourth quarter of 2006. Total crude oil and NGLs production increased to 337,240 bbl/d for the fourth quarter of 2007 from 323,662 bbl/d for the first quarter of 2006.

o Natural gas sales volumes

Natural gas sales volumes primarily reflected additional natural gas volumes as a result of the ACC acquisition and internally generated growth. The increases were partially offset by production declines due to the Company's strategic reduction in natural gas drilling activity. Total natural gas production increased to 1,589 mmcf/d for the fourth quarter of 2007 from 1,436 mmcf/d for the first quarter of 2006.

o Foreign exchange rates

A general strengthening of the Canadian dollar relative to the US dollar has decreased 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 balances and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars, offset by the impact of cross currency swaps. The US / Canadian dollar average exchange rate increased to US$1.0193 for the fourth quarter of 2007 from US$0.8660 for the first quarter of 2006. The US dollar / UK pound sterling average exchange rate increased to US$2.0451 for the fourth quarter of 2007 from US$1.7532 for the first quarter of 2006.

o Risk management

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

o Changes in income tax expense

Income tax expense and recovery fluctuations include statutory tax rate and other legislative changes enacted or substantively enacted in the various periods. Income tax rate and other legislative changes reduced future income tax liabilities by $864 million for 2007 and $395 million for 2006.

o Stock-based compensation

Net earnings have fluctuated due to the recognition of realized and unrealized expenses and recoveries from the mark-to-market of the Company's stock-based compensation liability. Stock-based compensation expense reflected fluctuations in the Company's share price over the eight most recently completed quarters. The Company's share price increased 26% to $72.58 per share at December 31, 2007 from $57.63 per share at December 31, 2005.

o Production expense

Production expense has fluctuated company wide primarily due to production growth and industry-wide inflationary cost pressures in all segments.

o Depletion, depreciation and amortization

Depletion, depreciation and amortization expense has increased primarily due to overall increases in finding and development costs associated with crude oil and natural gas exploration, increased estimated future costs to develop the Company's proved undeveloped reserves, and a higher depletion base in North America related to the ACC acquisition, together with the impact of higher sales volumes.

<TABLE>
<CAPTION>
BUSINESS ENVIRONMENT

(Yearly average)	2007	2006	2005
<S>	<C>	<C>	<C>
WTI benchmark price (US$/bbl)	$ 72.40	$ 66.25	$ 56.61
Dated Brent benchmark price (US$/bbl)	$ 72.59	$ 65.18	$ 54.45
Differential to LLB blend (US$/bbl)	$ 23.05	$ 21.69	$ 20.83
LLB blend differential from WTI (%)	32%	33%	37%
Condensate benchmark price (US$/bbl)	$ 72.88	$ 66.24	$ 57.25
NYMEX benchmark price (US$/mmbtu)	$ 6.92	$ 7.26	$ 8.56
AECO benchmark price (C$/GJ)	$ 6.26	$ 6.62	$ 8.05
US / Canadian dollar average exchange rate	$ 0.9304	$ 0.8818	$ 0.8253
US / Canadian dollar year end exchange rate	$ 1.0120	$ 0.8581	$ 0.8577

</TABLE>

COMMODITY PRICES

Substantially all of the Company's crude oil and natural gas production is sold based directly or indirectly on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on NYMEX and AECO reference pricing. As pricing is based on US dollar benchmarks, the price the Company ultimately receives in Canadian dollars fluctuates with changes in the US / Canadian dollar exchange rate. Accordingly, 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. The average value of the Canadian dollar strengthened 6% in 2007 compared to 2006.

Increases in WTI pricing in 2007 reflected continued strong demand for crude oil and continued geopolitical events resulting in increased market uncertainty and price volatility. In December 2007, WTI averaged US$91.74 per bbl, down 8% from the record high of US$99.29 per bbl reached in November 2007. WTI averaged US$72.40 per bbl for 2007, an increase of 9% compared to US$66.25 per bbl for 2006 (2005 - US$56.61 per bbl).

Brent averaged US$72.59 per bbl for 2007, an increase of 11% compared to US$65.18 per bbl for 2006 (2005 - US$54.45 per bbl). Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Brent pricing, which continued to benefit from strong European and Asian demand in 2007.

The Company's realized crude oil price increased from 2006 as a result of the increased WTI and Brent pricing and the narrower Heavy Differential, offset by the impact of a strengthening Canadian dollar. The Heavy Differential averaged 32% for 2007, which was comparable to 33% for 2006 (2005 - 37%). Realized prices continued to be adversely impacted by the stronger Canadian dollar.

The Company anticipates continued volatility in the crude oil pricing benchmarks due to the unpredictable nature of geopolitical events and potential unplanned refinery outages. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery cracking margins.

NYMEX natural gas prices averaged US$6.92 per mmbtu for 2007, a decrease of 5% from US$7.26 per mmbtu for 2006 (2005 - US$8.56 per mmbtu). AECO natural gas pricing for 2007 decreased 5% to average $6.26 per GJ from $6.62 per GJ in 2006 (2005 - $8.05 per GJ). Fluctuations in natural gas prices from 2006 were primarily related to lower overall demand resulting from the milder weather, reduced economic activity in the US, and higher liquefied natural gas imports into the US during the first half of 2007. Natural gas inventory levels in North America during 2007 continued to remain high due to stable annual production levels in the US that more than offset production declines in Canada from reduced drilling activity.

OPERATING, ROYALTY AND CAPITAL COSTS

Strong commodity prices in recent years have resulted in increased demand and costs for oilfield services worldwide. This has led to inflationary operating and capital cost pressures throughout the North America crude oil and natural gas industry, particularly related to drilling activities and oil sands developments. The strong commodity price environment has also impacted costs in international basins, due in large part to the high demand for offshore drilling rigs.

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. 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 CO2 annually. In the UK, GHG regulations have been in effect since 2005. The Company has strategies in place to ensure compliance with any requirements currently in effect. The additional requirements of enacted and proposed GHG legislation will add to the cost of executing projects company wide. For additional details, refer to the "Greenhouse Gas and Other Air Emissions" section of this MD&A.

In 2007, the Province of Alberta issued certain details of its proposed changes to the Alberta crude oil and natural gas royalty regime, effective January 1, 2009. These proposed changes include:

o 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; and

o New royalty formulas for conventional crude oil and natural gas that are to operate on sliding scales ranging up to 50% determined by commodity prices and well productivity.

The Company is currently awaiting finalization of the royalty implementation regulations, however it expects that its 2009 and future Alberta royalty payments will increase as a result of the proposed royalty changes and that its level of activity in Alberta in aggregate will be reduced from what it otherwise would have been in the absence of such royalty changes.

<TABLE>
<CAPTION>
ANALYSIS OF CHANGES IN REVENUE, BEFORE ROYALTIES AND RISK MANAGEMENT ACTIVITIES

Changes due to ($ millions)	2005	CHANGES DUE TO Volumes	Prices	Other	2006	CHANGES DUE TO VOLUMES	PRICES	OTHER	2007
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
NORTH AMERICA									
Crude Oil and NGLs	$ 4,317	$ 198	$ 747	$ -	$ 5,262	$ 298	$ 287	$ -	$ 5,847
Natural Gas	4,638	168	(1,002)	-	3,804	452	46	-	4,302
	8,955	366	(255)	-	9,066	750	333	-	10,149
NORTH SEA									
Crude oil and NGLs	1,636	(168)	132	-	1,600	(107)	82	-	1,575
Natural gas	23	(4)	(3)	-	16	(2)	8	-	22
	1,659	(172)	129	-	1,616	(109)	90	-	1,597
OFFSHORE WEST AFRICA									
Crude oil and NGLs	476	344	111	-	931	(216)	36	-	751
Natural gas	9	12	(2)	-	19	5	1	-	25
	485	356	109	-	950	(211)	37	-	776
SUBTOTAL									
Crude oil and NGLs	6,429	374	990	-	7,793	(25)	405	-	8,173
Natural gas	4,670	176	(1,007)	-	3,839	455	55	-	4,349
	11,099	550	(17)	-	11,632	430	460	-	12,522
MIDSTREAM	77	-	-	(5)	72	-	-	2	74
INTERSEGMENT ELIMINATIONS AND OTHER (1)	(46)	-	-	(15)	(61)	-	-	8	(53)
TOTAL	$ 11,130	$ 550	$ (17)	$ (20)	$ 11,643	$ 430	$ 460	$ 10	$ 12,543

</TABLE>
(1) ELIMINATES PRIMARILY INTERNAL TRANSPORTATION AND ELECTRICITY CHARGES.

Revenue increased 8% to $12,543 million for 2007 from $11,643 million for 2006 (2005 - $11,130 million). The increase was primarily due to increased crude oil and NGLs and natural gas sales volumes in North America and increased realized crude oil and NGLs and natural gas prices company wide.

For 2007, 19% of the Company's crude oil and natural gas revenue was generated outside of North America (2006 - 22%; 2005 - 19%). North Sea accounted for 13% of crude oil and natural gas revenue for 2007 (2006 - 14%; 2005 - 15%), and Offshore West Africa accounted for 6% of crude oil and natural gas revenue for 2007 (2006 - 8%; 2005 - 4%).

<TABLE>
<CAPTION>
ANALYSIS OF PRODUCT PRICES

	2007	2006	2005
<S>	<C>	<C>	<C>
CRUDE OIL AND NGLS ($/bbl) (1) (2)			
North America	$ 49.16	$ 46.52	$ 39.62
North Sea	$ 74.99	$ 72.62	$ 66.57
Offshore West Africa	$ 71.68	$ 67.99	$ 59.91
Company average	$ 55.45	$ 53.65	$ 46.86
NATURAL GAS ($/mcf) (1) (2)			
North America	$ 6.87	$ 6.77	$ 8.65
North Sea	$ 4.26	$ 2.66	$ 3.17
Offshore West Africa	$ 5.68	$ 5.37	$ 5.91
Company average	$ 6.85	$ 6.72	$ 8.57
COMPANY AVERAGE ($/boe) (1) (2)	$ 49.05	$ 47.92	$ 48.77
PERCENTAGE OF GROSS REVENUE (2) (excluding midstream revenue)			
Crude oil and NGLs	62%	64%	54%
Natural gas	38%	36%	46%

</TABLE>
(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 3% to average $55.45 per bbl for 2007 from $53.65 per bbl for 2006 (2005 - $46.86 per bbl). The increase from 2006 was due to increased benchmark crude oil prices and a slightly narrower Heavy Differential, largely offset by the impact of the stronger Canadian dollar.

The Company's realized natural gas price increased 2% to average $6.85 per mcf for 2007 from $6.72 per mcf for 2006 (2005 - $8.57 per mcf). Fluctuations in natural gas prices from 2006 were primarily related to the impact of both weather and storage levels.

NORTH AMERICA

North America realized crude oil prices increased 6% to average $49.16 per bbl for 2007 from $46.52 per bbl for 2006 (2005 - $39.62 per bbl). The increase from 2006 was due to increased benchmark crude oil prices and a slightly narrower Heavy Differential, largely offset by the impact of the stronger Canadian dollar.

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 2007, the Company contributed approximately 140,000 bbl/d of heavy crude oil blends to the Western Canadian Select stream.

North America realized natural gas prices increased slightly to average $6.87 per mcf for 2007 from $6.77 per mcf for 2006 (2005 - $8.65 per mcf), primarily related 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:

<TABLE>

	2007	2006	2005
<S>	<C>	<C>	<C>
Wellhead Price (1) (2)			
Light / medium crude oil and NGLs (C$/bbl)	$ 66.24	$ 63.09	$ 58.41
Pelican Lake crude oil (C$/bbl)	$ 46.29	$ 45.02	$ 38.39
Primary heavy crude oil (C$/bbl)	$ 43.77	$ 41.35	$ 33.53
Thermal heavy crude oil (C$/bbl)	$ 43.49	$ 40.98	$ 32.29
Natural gas (C$/mcf)	$ 6.87	$ 6.77	$ 8.65

</TABLE>
(1) NET OF TRANSPORTATION AND BLENDING COSTS AND EXCLUDING RISK MANAGEMENT ACTIVITIES.
(2) AMOUNTS EXPRESSED ON A PER UNIT BASIS ARE BASED ON SALES VOLUMES. NORTH SEA

North Sea realized crude oil prices increased 3% to average $74.99 per bbl for 2007 from $72.62 per bbl for 2006 (2005 - $66.57 per bbl). Realized crude oil prices in the North Sea during 2007 continued to benefit from the impact of strong European and Asian demand, partially offset by the impact of the stronger Canadian dollar.

OFFSHORE WEST AFRICA

Offshore West Africa realized crude oil prices increased 5% to average $71.68 per bbl for 2007 from $67.99 per bbl for 2006 (2005 - $59.91 per bbl). As all revenue in Offshore West Africa is currently recognized on a liftings basis, realized crude oil prices per barrel in any particular period are dependant on the frequency and timing of liftings of each field, as well as the terms of the related sales contracts. Realized crude oil prices in Offshore West Africa during 2007 continued to benefit from the impact of strong European and Asian demand, partially offset by the impact of the stronger Canadian dollar.

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 inventory volumes by segment, which have not been recognized in revenue, were as follows:

<TABLE>

(bbl)	2007	2006	2005
<S>	<C>	<C>	<C>
North America, related to pipeline fill	1,097,526	1,097,526	484,157
North Sea, related to timing of liftings	1,032,723	910,796	747,141
Offshore West Africa, related to timing of liftings	8,578	113,774	412,841
	2,138,827	2,122,096	1,644,139

</TABLE>

In 2007, net production of approximately 17,000 barrels of crude oil produced in the Company's international operations was deferred and included in inventory at December 31, 2007, reducing cash flow from operations by approximately $9 million.

<TABLE>
<CAPTION>
ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2007	2006	2005
<S>	<C>	<C>	<C>
CRUDE OIL AND NGLS (bbl/d)			
North America	246,779	235,253	221,669
North Sea	55,933	60,056	68,593
Offshore West Africa	28,520	36,689	22,906
	331,232	331,998	313,168
NATURAL GAS (mmcf/d)			
North America	1,643	1,468	1,416
North Sea	13	15	19
Offshore West Africa	12	9	4
	1,668	1,492	1,439
TOTAL BARRELS OF OIL EQUIVALENT (boe/d)	609,206	580,724	552,960
PRODUCT MIX			
Light crude oil and NGLs	23%	26%	26%
Pelican Lake crude oil	6%	5%	4%
Primary heavy crude oil	15%	16%	17%
Thermal heavy crude oil	11%	11%	10%
Natural gas	45%	42%	43%

</TABLE>

<TABLE>
<CAPTION>
DAILY PRODUCTION, NET OF ROYALTIES

	2007	2006	2005
<S>	<C>	<C>	<C>
CRUDE OIL AND NGLS (bbl/d)			
North America	210,769	205,382	191,751
North Sea	55,825	59,940	68,487
Offshore West Africa	26,012	35,212	22,293
	292,606	300,534	282,531
NATURAL GAS (mmcf/d)			
North America	1,378	1,185	1,125
North Sea	13	15	18
Offshore West Africa	11	9	4
	1,402	1,209	1,147
TOTAL BARRELS OF OIL EQUIVALENT (boe/d)	526,193	502,024	473,742

</TABLE>

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 of crude oil and NGLs before royalties decreased marginally to 331,232 bbl/d for 2007 from 331,998 bbl/d for 2006 (2005 - 313,168 bbl/d). The decrease in crude oil and NGLs production from 2006 primarily reflected lower production in the North Sea due to the timing of planned maintenance activities and reduced production from the Baobab Field in Offshore West Africa, offset by increased production in North America. Crude oil and NGLs production for 2007 was within the Company's guidance.

Natural gas production continues to represent the Company's largest product offering, accounting for 45% of the Company's total production. Total natural gas production before royalties increased 12% to 1,668 mmcf/d for 2007 from 1,492 mmcf/d for 2006 (2005 - 1,439 mmcf/d). The increase in natural gas production from 2006 primarily reflected additional natural gas production from the ACC acquisition, partially offset by production declines due to the Company's strategic reduction in natural gas drilling activity. Natural gas production for 2007 was within the Company's guidance.

For 2008, annual production is forecasted to average between 316,000 and 366,000 bbl/d of crude oil and NGLs and between 1,429 and 1,513 mmcf/d of natural gas.

NORTH AMERICA

North America crude oil and NGLs production for 2007 increased 5% to average 246,779 bbl/d from 235,253 bbl/d for 2006 (2005 - 221,669 bbl/d). The increase in production from 2006 was primarily due to the results from the Pelican Lake project, the cyclic nature of the Company's thermal production, and the ACC acquisition.

North America natural gas production for 2007 increased 12% to average 1,643 mmcf/d from 1,468 mmcf/d for 2006 (2005 - 1,416 mmcf/d). The increase in natural gas production from 2006 reflected the impact of the ACC acquisition, partially offset by production declines in 2007 due to the Company's strategic decision to reduce natural gas drilling activity.

NORTH SEA

North Sea crude oil production for 2007 was 55,933 bbl/d, a decrease of 7% from 60,056 bbl/d for 2006 (2005 - 68,593 bbl/d) due to the timing of planned maintenance activities, lower than anticipated production from the Lyell Field development and water injection problems experienced during the year at the Ninian Field. The Ninian water injection issues were resolved in the fourth quarter of 2007.

OFFSHORE WEST AFRICA

Offshore West Africa crude oil production for 2007 decreased 22% to 28,520 bbl/d from 36,689 bbl/d for 2006 (2005 - 22,906 bbl/d). Production decreased from 2006 due to continued challenges with sand production at the Baobab Field where 5 of 10 production wells remain shut in. The Company has secured a deepwater rig, expected in mid-year 2008, that should enable the Company to execute its plan to return certain of the shut-in wells to production over the course of 2008 and 2009. At the Espoir Fields, production delivered in 2007 was in line with expectations, reflecting the successful execution of the drilling campaign at the West Espoir Field.

<TABLE>
<CAPTION>
ROYALTIES

	2007	2006	2005
<S>	<C>	<C>	<C>
CRUDE OIL AND NGLS ($/bbl) (1)			
North America	$ 7.19	$ 5.86	$ 5.37
North Sea	$ 0.14	$ 0.13	$ 0.10
Offshore West Africa	$ 6.40	$ 2.81	$ 1.62
Company average	$ 5.94	$ 4.48	$ 3.97
NATURAL GAS ($/mcf) (1)			
North America	$ 1.12	$ 1.31	$ 1.78
North Sea	$ -	$ -	$ -
Offshore West Africa	$ 0.51	$ 0.22	$ 0.16
Company average	$ 1.11	$ 1.29	$ 1.75
COMPANY AVERAGE ($/boe) (1)	$ 6.26	$ 5.89	$ 6.82
PERCENTAGE OF REVENUE (2)			
Crude oil and NGLs	11%	8%	8%
Natural gas	16%	19%	20%
Boe	13%	12%	14%

</TABLE>
(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

Crown 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 are calculated as 1% of gross revenues until the Company's capital investments in the applicable project are fully recovered, at which time the royalty increases to 25% of net profit. Effective January 1, 2009, proposed changes to the Alberta royalty regime 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.

Crude oil and NGLs royalties for 2007 continued to reflect strong realized crude oil prices and the impact of the full recovery of the Company's capital investments in the Primrose North and South Fields in 2006. Upon full recovery, Crown royalty rates on the Primrose North and South Fields increased from 1% of gross revenue to 25% of revenue less operating, capital and abandonment costs. North America crude oil and NGLs royalties per bbl are anticipated to average 14% to 16% of gross revenue for 2008, comparable to 15% for 2007 (2006 - 13%; 2005 - 14%).

Natural gas royalties per mcf generally fluctuate with natural gas prices and well productivity. Natural gas royalties per mcf decreased from 2006 primarily due to decreased benchmark natural gas prices and the impact of certain other adjustments. North America natural gas royalties per mcf are anticipated to average 17% to 20% of gross revenue for 2008, an increase from 16% for 2007 (2006 - 19%; 2005 - 21%).

Effective January 1, 2009, proposed new royalty formulas for conventional crude oil and natural gas are to operate on sliding scales ranging up to 50% determined by commodity prices and well productivity.

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 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 Company. Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. The Government's 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 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 9% for 2007 compared to 4% for 2006 (2005 - 3%). The increase in royalty rates from 2006 was due to 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. Offshore West Africa royalty rates are anticipated to average 12% to 17% of gross revenue for 2008.

<TABLE>
<CAPTION>
PRODUCTION EXPENSE

	2007	2006	2005
<S>	<C>	<C>	<C>
CRUDE OIL AND NGLS ($/bbl) (1)			
North America	$ 12.26	$ 11.73	$ 10.49
North Sea	$ 20.78	$ 17.57	$ 14.94
Offshore West Africa	$ 8.32	$ 7.45	$ 6.50
Company average	$ 13.34	$ 12.29	$ 11.17
NATURAL GAS ($/mcf) (1)			
North America	$ 0.90	$ 0.81	$ 0.71
North Sea	$ 2.17	$ 1.40	$ 2.44
Offshore West Africa	$ 1.48	$ 1.19	$ 1.05
Company average	$ 0.91	$ 0.82	$ 0.73
COMPANY AVERAGE ($/boe) (1)	$ 9.75	$ 9.14	$ 8.21

</TABLE>
(1) AMOUNTS EXPRESSED ON A PER UNIT BASIS ARE BASED ON SALES VOLUMES.

NORTH AMERICA

North America crude oil and NGLs production expense for 2007 increased 5% to $12.26 per bbl from $11.73 per bbl for 2006 (2005 - $10.49 per bbl). The increase in production expense from 2006 was primarily due to increased industry-wide cost pressures and a continuing upward trend in property taxes and lease rentals. During the second half of 2007, costs decreased as a result of the timing of primary steam cycles, lower cost of natural gas fuel for the Company's thermal operations, and higher production volumes in both Pelican Lake and Primrose production areas, where a large portion of costs are fixed in nature.

North America natural gas production expense for 2007 increased 11% to $0.90 per mcf from $0.81 per mcf for 2006 (2005 - $0.71 per mcf). This increase was primarily due to industry-wide cost pressures in 2006 and early 2007, a continuing upward trend in property taxes and lease rentals, as well as the Company's strategic reduction in natural gas drilling activity, decreasing natural gas sales throughout 2007 and increasing production expense per mcf on the fixed cost portion of production costs.

Production expense per boe for 2008 is anticipated to increase as a result of an overall reduction in budgeted volumes for 2008, while fixed costs, such as property taxes and lease rentals, continue to escalate.

NORTH SEA

North Sea crude oil production expense increased on a per barrel basis from 2006 due to planned maintenance shutdowns, varying production volumes on a relatively fixed cost base, the timing of liftings from various fields, and the impact of the stronger Canadian dollar.

OFFSHORE WEST AFRICA

Offshore West Africa crude oil production expense on a per barrel basis increased from 2006 primarily due to the impact of continuing operating challenges with sand production at the Baobab Field, resulting in decreased production volumes on a relatively fixed operating cost base. Production expense was positively impacted by the impact of the stronger Canadian dollar.

MIDSTREAM

($ millions)	2007	2006	2005
Revenue	$ 74	$ 72	$ 77
Production expense	22	23	24
Midstream cash flow	52	49	53
Depreciation	8	8	8
Segment earnings before taxes	$ 44	$ 41	$ 45

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)	2007	2006	2005
North America	$ 2,350	$ 1,897	$ 1,595
North Sea	$ 340	$ 297	$ 306
Offshore West Africa	$ 165	$ 189	$ 104
Expense	$ 2,855	$ 2,383	$ 2,005
$/boe	$ 12.84	$ 11.27	$ 10.02

(1) DD&A EXCLUDES DEPRECIATION ON MIDSTREAM ASSETS.
(2) AMOUNTS EXPRESSED ON A PER UNIT BASIS ARE BASED ON SALES VOLUMES.

Depletion, Depreciation and Amortization ("DD&A") expense for 2007 increased 20% to $2,855 million from $2,383 million for 2006 (2005 - $2,005 million). The increase in DD&A expense in total and on a boe basis in 2007 from 2006 was primarily due to overall increases in finding and development costs associated with crude oil and natural gas exploration, increased estimated future costs to develop the Company's proved undeveloped reserves, and a higher depletion base in North America related to the ACC acquisition, together with the impact of higher sales volumes. The increase in DD&A expense in 2007 was partially offset in the North Sea and Offshore West Africa by the impact of the stronger Canadian dollar relative to the US dollar.

ASSET RETIREMENT OBLIGATION ACCRETION

($ millions, except per boe amounts) (1)	2007	2006	2005
North America	$ 38	$ 35	$ 34
North Sea	$ 30	$ 31	$ 34
Offshore West Africa	$ 2	$ 2	$ 1
Expense ($ millions)	$ 70	$ 68	$ 69
$/boe	$ 0.32	$ 0.32	$ 0.34

(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 was comparable to 2006.

ADMINISTRATION EXPENSE

($ millions, except per boe amounts) (1)	2007	2006	2005
Net expense ($ millions)	$ 208	$ 180	$ 151
$/boe	$ 0.93	$ 0.85	$ 0.75

(1) AMOUNTS EXPRESSED ON A PER UNIT BASIS ARE BASED ON SALES VOLUMES.

Net administration expense for 2007 increased in total and on a boe basis from 2006 primarily due to increased staffing and administrative costs and overall inflationary cost pressures.

STOCK-BASED COMPENSATION

($ millions)	2007	2006	2005
Stock-based compensation expense	$ 193	$ 139	$ 723

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 since 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 $193 million ($134 million after-tax) stock-based compensation expense during 2007 in connection with the 17% appreciation in the Company's share price (December 31, 2007 - C$72.58; December 31, 2006 - C$62.15; December 31, 2005 - C$57.63; December 31, 2004 - C$25.63). As required by GAAP, the Company's outstanding stock options are valued 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 period, 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, 2007, the Company capitalized $58 million in stock-based compensation as part of the Horizon Project (2006 - $79 million; 2005 - $101 million). The stock-based compensation liability at December 31, 2007 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, 2007. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the year ended December 31, 2007, the Company paid $375 million for stock options surrendered for cash settlement (2006 - $264 million; 2005 - $227 million).

<TABLE>
<CAPTION>
INTEREST EXPENSE

($ millions, except per boe amounts and interest rates) (1)	2007	2006	2005
<S>	<C>	<C>	<C>
Interest expense, gross	$ 632	$ 336	$ 221
Less: capitalized interest, Horizon Project	356	196	72
Interest expense, net	$ 276	$ 140	$ 149
$/boe	$ 1.24	$ 0.66	$ 0.74
Average effective interest rate	5.5%	5.7%	5.6%

</TABLE>
(1) AMOUNTS EXPRESSED ON A PER UNIT BASIS ARE BASED ON SALES VOLUMES.

Gross interest expense increased from 2006 primarily due to increased debt levels associated with the ACC acquisition and the on-going financing of Horizon Project capital expenditures.

The Company's average effective interest rate for 2007 reflected the impact of the stronger Canadian dollar, offset by higher cost US dollar denominated debt issued in March 2007 and the impact of higher short-term lending rates on the Company's floating rate debt due to credit market uncertainty.

In 2008, upon commencement of operations of Phase 1 of the Horizon Project, interest capitalization will cease on this Phase, increasing interest expense accordingly.

RISK MANAGEMENT ACTIVITIES

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

Commencing January 1, 2007, the Company adopted new accounting standards issued by the CICA relating to the accounting for and disclosure of financial instruments and comprehensive income.

Adoption of these standards required the Company to record all of its derivative financial instruments on the balance sheet at estimated fair value as at January 1, 2007, including those designated as hedges. Designated hedges, other than cross currency swaps, were previously not recognized on the balance sheet but were disclosed in the notes to the financial statements. The adjustment to recognize the designated hedges on the balance sheet was recorded as an adjustment to the opening balance of retained earnings or accumulated other comprehensive income, as appropriate.

With the exception of the foreign currency translation adjustment, these standards were adopted prospectively; accordingly, comparative amounts for prior periods have not been restated. The reclassification of the foreign currency translation adjustment to other comprehensive income was applied retroactively with prior period restatement.

The effects of adopting these standards on the opening balance sheet were as follows:

<TABLE>

($ millions)	JANUARY 1, 2007
<S>	<C>
Increased current portion of other long-term assets (1)	$ 193
Decreased other long-term assets (2)	$ (16)
Decreased long-term debt (3)	$ (72)
Increased retained earnings (4)	$ 10
Increased foreign currency translation adjustment (5)	$ 13
Increased accumulated other comprehensive income (6)	$ 146
Decreased current portion of future income tax asset (7)	$ (62)
Increased future income tax liability (7)	$ 18

</TABLE>

(1) RELATES TO THE RECOGNITION OF THE CURRENT PORTION OF THE FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS DESIGNATED AS CASH FLOW HEDGES.
(2) RELATES TO THE RECOGNITION OF THE LONG-TERM PORTION OF THE FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS DESIGNATED AS CASH FLOW AND FAIR VALUE HEDGES, AS WELL AS THE RECLASSIFICATION OF TRANSACTION COSTS AND ORIGINAL ISSUE DISCOUNTS FROM DEFERRED CHARGES TO LONG-TERM DEBT.
(3) RELATES TO THE FAIR VALUE IMPACT OF DERIVATIVE FINANCIAL INSTRUMENTS DESIGNATED AS FAIR VALUE HEDGES, AS WELL AS THE RECLASSIFICATION OF TRANSACTION COSTS AND ORIGINAL ISSUE DISCOUNTS.
(4) RELATES TO THE IMPACT ON ADOPTION OF THE MEASUREMENT OF INEFFECTIVENESS ON DERIVATIVE FINANCIAL INSTRUMENTS DESIGNATED AS CASH FLOW HEDGES.
(5) RELATES TO THE RETROACTIVE RESTATEMENT OF FOREIGN CURRENCY TRANSLATION ADJUSTMENT TO ACCUMULATED OTHER COMPREHENSIVE INCOME.
(6) RELATES TO THE RECOGNITION OF ACCUMULATED OTHER COMPREHENSIVE INCOME ARISING FROM THE MEASUREMENT OF EFFECTIVENESS ON DERIVATIVE FINANCIAL INSTRUMENTS DESIGNATED AS CASH FLOW HEDGES.
(7) RELATES TO THE FUTURE INCOME TAX IMPACTS OF THE ABOVE NOTED ADJUSTMENTS.

Effective January 1, 2007, all derivative financial instruments are recognized at estimated fair value on the consolidated balance sheet at each balance sheet date. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. However, these 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.

The Company formally documents all derivative financial instruments that are 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 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 immediately 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.

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. Gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in consolidated net earnings immediately.

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.

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.

<TABLE>
<CAPTION>
RISK MANAGEMENT ACTIVITIES

($ millions)	2007	2006	2005
<S>	<C>	<C>	<C>
REALIZED LOSS (GAIN)			
Crude oil and NGLs financial instruments	$ 505	$ 1,395	$ 753
Natural gas financial instruments	(343)	(70)	283
Interest rate swaps	-	-	(9)
	$ 162	$ 1,325	$ 1,027
UNREALIZED LOSS (GAIN)			
Crude oil and NGLs financial instruments	$ 1,244	$ (736)	$ 847
Natural gas financial instruments	156	(260)	77
Interest rate and cross-currency swaps	-	(17)	1
	$ 1,400	$ (1,013)	$ 925
TOTAL	$ 1,562	$ 312	$ 1,952

</TABLE>
The realized losses (gains) from crude oil and NGLs and natural gas financial instruments would have decreased (increased) the Company's average realized prices as follows:

<TABLE>

2007	2006	2005
<S>	<C>	<C>	<C>
Crude oil and NGLs ($/bbl) (1)	$ 4.18	$ 11.57	$ 6.68
Natural gas ($/mcf) (1)	$ (0.56)	$ (0.13)	$ 0.54

</TABLE>
(1) AMOUNTS EXPRESSED ON A PER UNIT BASIS ARE BASED ON SALES VOLUMES.

Complete details related to outstanding derivative financial instruments at December 31, 2007 are disclosed in note 12 to the Company's consolidated financial statements. As at December 31, 2006, the net unrecognized asset related to the estimated fair values of derivative financial instruments designated as hedges was $222 million (December 31, 2005 - net unrecognized liability of $990 million).

As effective as the Company's hedges are against reference commodity prices, a substantial portion of the commodity derivative financial instruments entered into by the Company have not been formally designated as hedges for accounting purposes or do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The change in the fair value of the 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 risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at December 31, 2007. Due to changes in the crude oil and natural gas forward pricing, and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized loss of $1,400 million ($977 million after-tax) on its commodity risk management activities for the year ended December 31, 2007 (2006 - - $1,013 million unrealized gain, $674 million after-tax; 2005 - $925 million unrealized loss, $607 million after-tax).

FOREIGN EXCHANGE

($ millions)	2007	2006	2005
Realized foreign exchange loss (gain)	$ 53	$ (12)	$ (29)
Unrealized foreign exchange (gain) loss	(524)	134	(103)
Total	$ (471)	$ 122	$ (132)

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.

The Company's Offshore West Africa foreign operations are classified as integrated for the purposes of foreign currency translation. Offshore West Africa foreign operations and foreign currency transactions and balances held in North America are directly translated into Canadian dollars using the temporal method, whereby 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. Revenue and expenses are translated to Canadian dollars at the monthly average exchange rates. All related foreign exchange gains or losses are 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 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, while production expenses in Offshore West Africa are subject to foreign currency fluctuations due to changes in the exchange rate of the Canadian dollar 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 gain in 2007 was primarily related to the strengthening of the Canadian dollar in relation to the US dollar with respect to the US dollar debt, partially offset by an unrealized loss of $350 million related to the impact of the cross currency swaps. The net realized foreign exchange loss for 2007 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. The Canadian dollar ended the year above parity, at US$1.0120 compared to US$0.8581 at December 31, 2006 (December 31, 2005 - US$0.8577).

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 statement of earnings.

<TABLE>
<CAPTION>
TAXES

($ millions, except income tax rates)	2007	2006	2005
<S>	<C>	<C>	<C>
TAXES OTHER THAN INCOME TAX			
Current	$ 121	$ 219	$ 203
Deferred	44	37	(9)
	$ 165	$ 256	$ 194
CURRENT INCOME TAX			
North America	$ 96	$ 143	$ 99
North Sea	210	30	155
Offshore West Africa	74	49	32
	380	222	286
FUTURE INCOME TAX	(456)	652	353
	(76)	874	639
Income tax and other legislative changes (1) (2) (3)	864	395	19
	$ 788	$ 1,269	$ 658
EFFECTIVE INCOME TAX RATE BEFORE INCOME TAX RATE AND OTHER LEGISLATIVE CHANGES	31.1%	37.3%	39.0%

</TABLE>

(1) INCLUDES THE EFFECT OF ONE TIME RECOVERIES OF $864 MILLION DUE TO CANADIAN FEDERAL INCOME TAX RATE REDUCTIONS AND OTHER LEGISLATIVE CHANGES ENACTED OR SUBSTANTIVELY ENACTED DURING 2007.

(2) 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 OFFSHORE WEST AFRICA CORPORATE INCOME TAX RATE REDUCTIONS ENACTED IN 2006.

(3) INCLUDES THE EFFECT OF A ONE TIME RECOVERY OF $19 MILLION DUE TO A BRITISH COLUMBIA CORPORATE INCOME TAX RATE REDUCTION ENACTED IN 2005.

Taxes other than income tax primarily includes current and deferred petroleum revenue tax ("PRT"). PRT is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including 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 a future period. North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the nature, timing and amount of capital expenditures incurred in Canada in any particular year. In particular, current taxes in a specific year are sensitive to the timing of when the Horizon Project capital expenditures are deductible for Canadian income tax purposes.

During 2007, the Canadian Federal Government enacted or substantively enacted income tax rate and other legislative changes, resulting in a reduction of future income tax liabilities of approximately $864 million. As a result of the enacted income tax rate changes, the federal corporate income tax rate will be reduced over the next five years from 21% in 2007 to 15% in 2012.

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 2005, enacted income tax rate changes in North America resulted in a reduction of future income tax liabilities of approximately $19 million.

During 2003, the Canadian Federal Government enacted legislation to change the taxation of resource income. The legislation reduced the corporate income tax rate on resource income from 28% to 21% over five years beginning January 1, 2003. Over the same period, the deduction for resource allowance was phased out and a deduction for actual crown royalties paid was phased in. As a result, in 2007 crown royalties were fully deductible and the Company is no longer eligible for the resource allowance.

The Company's consolidated effective income tax rate for 2007 was reduced primarily due to income tax rate reductions enacted in Canada during the year, the effects of the non-taxable portion of unrealized foreign exchange gains on US dollar debt, net of unrealized losses on cross currency swaps, and adjustments to future tax expense in Canada related to the final phase-in of deductibility of crown royalties and the elimination of the resource allowance deduction in 2007. For 2008, based on budgeted prices and the current availability of tax pools, the Company expects to be cash taxable in Canada in the amount of $75 million to $150 million.

<TABLE>
<CAPTION>
NET CAPITAL EXPENDITURES (1)

($ millions)	2007	2006	2005
<S>	<C>	<C>	<C>
EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT			
Net property (dispositions) acquisitions (2)	$ (39)	$ 4,733	$ (320)
Land acquisition and retention	95	210	254
Seismic evaluations	124	130	132
Well drilling, completion and equipping	1,642	2,340	2,000
Production and related facilities	1,205	1,314	1,295
TOTAL NET RESERVE REPLACEMENT EXPENDITURES	3,027	8,727	3,361
Horizon Project:			
Phase 1 construction costs	2,740	2,768	1,249
Phases 2/3 costs	124	79	-
Capitalized interest, stock-based compensation and other	437	338	250
Total Horizon Project	3,301	3,185	1,499
Midstream	6	12	4
Abandonments (3)	71	75	46
Head office	20	26	22
TOTAL NET CAPITAL EXPENDITURES	$ 6,425	$ 12,025	$ 4,932
BY SEGMENT			
North America	$ 2,428	$ 7,936	$ 2,530
North Sea	439	646	387
Offshore West Africa	159	134	439
Other	1	11	5
Horizon Project	3,301	3,185	1,499
Midstream	6	12	4
Abandonments (3)	71	75	46
Head office	20	26	22
Total	$ 6,425	$ 12,025	$ 4,932

</TABLE>
(1) NET CAPITAL EXPENDITURES EXCLUDE ADJUSTMENTS RELATED TO DIFFERENCES BETWEEN CARRYING VALUE AND TAX VALUE.
(2) INCLUDES BUSINESS COMBINATIONS.
(3) ABANDONMENTS REPRESENT EXPENDITURES TO SETTLE ARO AND HAVE BEEN REFLECTED AS CAPITAL EXPENDITURES IN THIS TABLE.

The Company's 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, 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 2007 were $6,425 million compared to $12,025 million for 2006 (2005 - $4,932 million). Excluding the ACC acquisition, net capital expenditures were $7,270 million for 2006. Capital expenditures in 2007 reflected the continued progress on the Company's larger, future growth projects, most notably the Horizon Project, as well as continued industry-wide inflationary pressures, offset by the effects of an overall strategic reduction in the North America natural gas drilling program.

During 2007, the Company drilled a total of 1,322 net wells consisting of 383 natural gas wells, 592 crude oil wells, 254 stratigraphic test and service wells, and 93 wells that were dry. This compared to 1,738 net wells drilled for 2006 (2005 - 1,882 net wells). The Company achieved an overall success rate of 91% for 2007, excluding the stratigraphic test and service wells (2006 - 91%; 2005 - 93%).

NORTH AMERICA

North America, including the Horizon Project, accounted for approximately 91% of the total capital expenditures for the year ended December 31, 2007 compared to approximately 93% for 2006 (2005 - 83%).

During 2007, the Company targeted 450 net natural gas wells, including 58 wells in Northeast British Columbia, 133 wells in the Northern Plains region, 110 wells in Northwest Alberta, and 149 wells in the Southern Plains region. The Company also targeted 610 net crude oil wells during the year. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 362 primary heavy crude oil wells, 127 Pelican Lake crude oil wells, 55 thermal crude oil wells and 6 light crude oil wells were drilled. In addition, 60 wells targeting light crude oil were drilled outside the Northern Plains region.

Due to significant changes in relative commodity prices between crude oil and natural gas, the Company has continued to access its large crude oil drilling inventory to maximize value in both the short and long term. As a result of the Company's focus on drilling crude oil wells in 2007, natural gas drilling activities were reduced to manage overall capital spending. Deferred natural gas well locations have been retained in the Company's prospect inventory. Drilling on ACC acquired lands was optimized as part of the overall capital program.

In November of 2005, the Company announced a phased expansion of its In-Situ Oil Sands Assets. As part of the development, the Company is continuing to develop its Primrose thermal projects. During 2007, the Company drilled 135 stratigraphic test wells and observation wells, 2 water source wells and 55 thermal oil wells. Overall Primrose thermal production for 2007 was approximately 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, is anticipated to add approximately 40,000 bbl/d when complete. The Primrose East Expansion received Board of Directors' sanction in 2006 and the Alberta Energy and Utilities Board regulatory approval in early 2007. Drilling and construction are currently underway, and production is targeted to commence in 2009.

The next phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby project located 120 kilometers north of the existing Primrose facilities. The Kirby project is anticipated to add an additional 45,000 bbl/d of production growth. 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.

Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout 2007. Drilling consisted of 125 horizontal crude oil wells, with plans to drill 105 additional horizontal crude oil wells in 2008. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 34,000 bbl/d in 2007 (2006 - 30,000 bbl/d).

Due to growing concerns relating to increased environmental costs for upgraders located in Canada, inflationary capital cost pressures and narrowing heavy oil differentials in North America, the Company has, at this point in time, deferred the Design Basis memorandum and Engineering Design Specification of

the Canadian Natural Upgrader, outside of the Horizon Project, pending clarification on the cost of future environmental legislation and a more stable cost environment.

For 2008, the Company's overall drilling activity in North America is expected to comprise approximately 314 natural gas wells and 526 crude oil wells, excluding stratigraphic and service wells.

HORIZON PROJECT

The Horizon Project is designed as a phased development and includes two components: the mining of bitumen and an onsite upgrader. Phase 1 production is targeted to commence in the third quarter of 2008 ramping up to 110,000 bbl/d of 34(degree) API SCO.

Work progress on the Horizon Project was 90% complete at year end. The project status as at December 31, 2007 was as follows:

o Overall detailed engineering 98.5% complete and substantially complete in most areas;

o Overall procurement 99% complete with over $5.6 billion in purchase orders and contracts awarded;

o Commenced receipt and site assembly of Mine Operations equipment (Shovels and Heavy Haul Trucks);

o Overall construction progress 85% complete;

o Mine overburden removal approximately 72% complete and 0.6 million bank cubic meters ahead of schedule;

o Main Control Room Distributed Control Systems equipment powered and tested;

o Commissioned 260kV Transmission Line and turned over to operations;

o Commissioned Raw Water Pumphouse and turned over to operations;

o Completed reformer erection in Hydrogen Plant;

o Completed installation and pre-commissioning of CPI Separator Building;

o Completed the closure of Dyke 10 (external tailings pond) in Mining;

o Completed erection of Crushing Plants and conveyors in Ore Preparation Area;

o Completed Primary Separation Cells in Extraction; and

o Completed construction of Main Laboratory.

The Company has budgeted construction costs of approximately $1.7 billion to $1.9 billion for 2008 related to the planned completion of Phase 1 of the Horizon Project.

NORTH SEA

In 2007, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations, and the execution of its long-term facilities strategy. During 2007, 7.2 net wells were drilled, including 3.5 net water injectors, with an additional 1.6 net wells drilling at year end.

Commissioning of the Columba E Raw Water Injection project was successfully completed on time and on budget during 2007 and 2 water injection wells were delivered, allowing water injection into the reservoir to commence. Injection rates delivered were below expectation due to lower reservoir quality. A detailed technical evaluation has been carried out and is being executed to deliver required injection rates under sustained fracture conditions.

During 2007, the subsea project to bring gas lift to the Kyle Field was successfully completed, delivering above expectation production at the Banff / Kyle hub.

The development of the Lyell Field continued during the year with 2 production wells coming on stream through the existing infrastructure. Production from these initial Lyell wells was below expectation and future development plans are being re-evaluated as a result. The Company remains committed to unlocking the remaining development potential at the Lyell Field with a phased approach.

At the Ninian Field, the Company continued to execute its long-term facilities strategy, with investment in the Ninian South platform infrastructure in particular. In addition, infill locations were successfully developed, with production delivery from these wells in line with expectations, and water injection capacity was successfully increased.

In December 2007, the Company completed the sale of its working interest in the B-Block, comprising the Balmoral, Stirling, and Glamis Fields.

OFFSHORE WEST AFRICA

During 2007, 4.7 net wells were drilled with 0.6 wells drilling at year end.

Development drilling on West Espoir continued during 2007 with 5 additional production wells and 2 additional injector wells added. West Espoir development drilling was completed in early 2008, on budget and on time.

During 2007, the Company awarded a contract for the upgrade of the Espoir FPSO in order to increase the throughput handling capability of the vessel. Design and procurement work commenced during the year. Production volumes will not be significantly impacted during the installation work, scheduled to complete in late 2009. Gross fluids processing capacity will increase from 50,000 bbl/d to 70,000 bbl/d, with natural gas handling capacity increasing from 55 mmcf/d to 75 mmcf/d upon completion of the project.

At the 90% owned and operated Olowi Field in offshore Gabon, all major construction contracts have been awarded, and construction of the wellhead towers and the FPSO is ongoing. The project is on schedule with drilling targeted to commence in the second quarter of 2008 and first crude oil targeted in late 2008. Olowi production is targeted to plateau at approximately 20,000 bbl/d, net to the Company.

<TABLE>
<CAPTION>
LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	2007	2006	2005
<S>	<C>	<C>	<C>
Working capital deficit (1)	$ 1,382	$ 832	$ 1,774
Long-term debt (2)	$ 10,940	$ 11,043	$ 3,321
Shareholders' equity			
Share capital	$ 2,674	$ 2,562	$ 2,442
Retained earnings	10,575	8,141	5,804
Accumulated other comprehensive income (loss)	72	(13)	(9)
Total	$ 13,321	$ 10,690	$ 8,237
Debt to book capitalization (2) (3)	45%	51%	29%
Debt to market capitalization (2) (4)	22%	25%	10%
After tax return on average common shareholders' equity (5)	22%	27%	14%
After tax return on average capital employed (2) (6)	12%	17%	10%

</TABLE>
(1) CALCULATED AS CURRENT ASSETS LESS CURRENT LIABILITIES.
(2) LONG-TERM DEBT AT DECEMBER 31, 2007 IS STATED AT ITS CARRYING VALUE, NET OF FAIR VALUE ADJUSTMENTS, ORIGINAL ISSUE DISCOUNTS AND TRANSACTION COSTS. AMOUNTS FOR PERIODS PRIOR TO JANUARY 1, 2007 WERE NOT ADJUSTED FOR THESE ITEMS.
(3) CALCULATED AS LONG-TERM DEBT; DIVIDED BY THE BOOK VALUE OF COMMON SHAREHOLDERS' EQUITY PLUS LONG-TERM DEBT.
(4) CALCULATED AS LONG-TERM DEBT; DIVIDED BY THE MARKET VALUE OF COMMON SHAREHOLDERS' EQUITY PLUS LONG-TERM DEBT.
(5) CALCULATED AS NET EARNINGS FOR THE YEAR; AS A PERCENTAGE OF AVERAGE COMMON SHAREHOLDERS' EQUITY FOR THE YEAR.
(6) 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 LONG-TERM DEBT FOR THE YEAR, INCLUDING $7,001 MILLION IN AVERAGE CAPITAL EMPLOYED RELATED TO THE HORIZON PROJECT (2006 - $3,760 MILLION; 2005 - $1,421 MILLION).

The Company's capital resources at December 31, 2007 consisted primarily of cash flow from operations, available 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 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. Management believes internally generated cash flows supported by the implementation of the Company's hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, the Company's existing credit facilities and the Company's ability to raise new debt on commercially acceptable terms, will be sufficient to sustain its operations and support its growth strategy. 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. The Company does not have any direct exposure to asset-backed commercial paper.

At December 31, 2007, the Company had undrawn bank lines of credit of $1,442 million. Details related to the Company's long-term debt at December 31, 2007 are disclosed in note 5 to the Company's audited annual consolidated financial statements. Subsequent to December 31, 2007, the Company issued an aggregate US$1,200 million of unsecured notes. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

At December 31, 2007, the Company's working capital deficit was $1,382 million and included the current portion of the stock-based compensation liability of $390 million and the current portion of the net mark-to-market liability for risk management derivative financial instruments of $1,227 million. 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. 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 of the derivative financial instruments, as compared to their mark-to-market value at December 31, 2007.

The Company believes it has the necessary financial capacity to complete the Horizon Project, while at the same time not compromising conventional crude oil and natural gas growth opportunities. The financing of Phase 1 of the Horizon Project development is guided by the competing principles of retaining as much direct ownership interest as possible while maintaining a strong balance sheet.

Long-term debt was $10,940 million at December 31, 2007, resulting in a debt to book capitalization level of 45% as at December 31, 2007 (December 31, 2006 - 51%). While this ratio is at the high end of the 35% to 45% range targeted by management, the Company remains committed to maintaining a strong balance sheet and flexible capital structure, and expects its debt to book capitalization ratio to be near the midpoint of the range in late 2008. While the Company believes that it has the balance sheet strength and flexibility to complete Phase 1 of the Horizon Project, as well as its other planned capital expenditure programs, the Company has hedged a significant portion of its crude oil and natural gas production for 2008 at prices that protect investment returns. 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 price markets and supports the Company's cash flow for its capital expenditures throughout the Horizon Project construction period. This program allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 65% of expected crude oil volumes are hedged for 2008 and approximately 53% of expected natural gas volumes are hedged for the first quarter of 2008. Subsequent to December 31, 2007, the Company hedged 25,000 bbl/d of crude oil volumes for 2009 using WTI collars with a US$70.00 floor.

The Company has the following commodity related net financial derivatives outstanding as at December 31, 2007:

<TABLE>

REMAINING TERM	VOLUME	WEIGHTED AVERAGE PRICE	INDEX
<S>	<C>	<C>	<C>
CRUDE OIL			
Crude oil price collars (1)	Jan 2008 - Mar 2008	50,000 bbl/d	US$60.00 - US$80.06 WTI
Jan 2008 - Jun 2008	25,000 bbl/d	US$60.00 - US$80.44	WTI
Apr 2008 - Sep 2008	25,000 bbl/d	US$60.00 - US$80.46	WTI
Jul 2008 - Sep 2008	25,000 bbl/d	US$70.00 - US$123.75	WTI
Oct 2008 - Dec 2008	25,000 bbl/d	US$70.00 - US$112.63	WTI
Jan 2008 - Dec 2008	20,000 bbl/d	US$50.00 - US$65.53	Mayan Heavy
Jan 2008 - Dec 2008	50,000 bbl/d	US$60.00 - US$75.22	WTI
Jan 2008 - Dec 2008	50,000 bbl/d	US$60.00 - US$76.05	WTI
Jan 2008 - Dec 2008	50,000 bbl/d	US$60.00 - US$76.98	WTI
Crude oil puts	Jan 2008 - Dec 2008	50,000 bbl/d	US$55.00 WTI
NATURAL GAS			
AECO price collars	Jan 2008 - Mar 2008	400,000 GJ/d	C$7.00 - C$14.08 AECO
Jan 2008 - Mar 2008	500,000 GJ/d	C$7.50 - C$10.81	AECO

</TABLE>

(1) SUBSEQUENT TO DECEMBER 31, 2007, THE COMPANY ENTERED INTO 25,000 BBL/D OF US$70.00 - US$111.56 WTI COLLARS FOR THE PERIOD JANUARY TO DECEMBER 2009.

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

LONG-TERM DEBT

The Company's long-term debt of $10,940 million at December 31, 2007 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, 2007, the Company had in place unsecured bank credit facilities of $6,209 million, comprised of:

o a $100 million demand credit facility;

o a non-revolving syndicated credit facility of $2,350 million maturing October 2009;

o a revolving syndicated credit facility of $2,230 million maturing June 2012;

o a revolving syndicated credit facility of $1,500 million maturing June 2012; and

o 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.

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 in October 2009. In March 2007, $1,500 million was repaid, reducing the facility to $2,350 million.

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $345 million, including $300 million related to the Horizon Project, were outstanding at December 31, 2007.

MEDIUM-TERM NOTES

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. After issuing these securities, 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.

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

In 2006, the Company issued $400 million of debt securities maturing January 2013, bearing interest at 4.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

SENIOR UNSECURED NOTES

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

US DOLLAR DEBT SECURITIES

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 2007, the Company de-designated the portion of its 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 statement of earnings.

In 2006, the Company issued US$250 million of unsecured notes maturing August 2016 and US$450 million of unsecured notes maturing February 2037, bearing interest at 6.00% and 6.50%, respectively. Concurrently, the Company entered into cross currency swaps to fix the Canadian dollar interest and principal repayment amounts on the US$250 million notes at 5.40% and C$279 million. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

In September 2007, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until October 2009.

Subsequent to December 31, 2007, the Company issued US$1,200 million of unsecured notes under this 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. If issued, these securities will bear interest as determined at the date of issuance.

SHARE CAPITAL

As at December 31, 2007, there were 539,729,000 common shares outstanding and 30,659,000 stock options outstanding. As at February 26, 2008, the Company had 540,252,000 common shares outstanding and 29,173,000 stock options outstanding.

During 2007, the Company did not purchase any common shares for cancellation pursuant to the Normal Course Issuer Bid previously filed for the 12-month period beginning January 24, 2007 and ending January 23, 2008 (2006 - 485,000 common shares were purchased at an average price of $57.33 per common share for a total cost of $28 million; 2005 - 850,000 common shares were purchased at an average price of $53.29 per common share for a total cost of $45 million). The Company has decided not to renew the Normal Course Issuer Bid until subsequent to the completion of Phase 1 of the Horizon Project.

In February 2008, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.40 per common share for 2008. The increase represents an 18% increase from the prior year, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. This is the eighth consecutive year in which the Company has paid dividends and the seventh consecutive year of an increase in the distribution paid to its Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change. In March 2007, an increase in the annual dividend paid by the Company was approved to $0.34 per common share for 2007. The increase represented a 13% increase from 2006.

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 debt repayments; operating leases relating to offshore FPSOs, drilling rigs and office space; and firm commitments for gathering, processing and transmission services; as well as expenditures relating to ARO. As at December 31, 2007, 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, 2007:

<TABLE>

($ millions)	2008	2009	2010	2011	2012	Thereafter
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Product transportation and pipeline	$ 232	$ 151	$ 137	$ 109	$ 91	$ 972
Offshore equipment operating lease (1)	$ 114	$ 129	$ 113	$ 111	$ 90	$ 387
Offshore drilling (2) (3)	$ 267	$ 185	$ 39	$ -	$ -	$ -
Asset retirement obligations (4)	$ 33	$ 4	$ 5	$ 4	$ 4	$ 4,376
Long-term debt (5)	$ 39	$ 2,361	$ 400	$ 395	$ 346	$ 5,098
Interest expense (6)	$ 612	$ 590	$ 487	$ 465	$ 374	$ 4,338
Office lease	$ 26	$ 28	$ 28	$ 22	$ 3	$ -
Electricity and other	$ 166	$ 173	$ 25	$ 4	$ -	$ -

</TABLE>

(1) OFFSHORE EQUIPMENT OPERATING LEASES ARE PRIMARILY COMPRISED OF OBLIGATIONS RELATED TO FPSOS. DURING 2006, THE COMPANY ENTERED INTO AN AGREEMENT TO LEASE AN ADDITIONAL FPSO COMMENCING IN 2008, IN CONNECTION WITH THE PLANNED OFFSHORE DEVELOPMENT IN GABON, OFFSHORE WEST AFRICA. DURING THE INITIAL TERM, THE TOTAL ANNUAL PAYMENTS FOR THE GABON FPSO ARE ESTIMATED TO BE US$50 MILLION.

(2) DURING 2007, THE COMPANY ENTERED INTO A ONE-YEAR AGREEMENT FOR OFFSHORE DRILLING SERVICES RELATED TO THE BAOBAB FIELD IN COTE D'IVOIRE, OFFSHORE WEST AFRICA. THE AGREEMENT IS SCHEDULED TO COMMENCE IN 2008, SUBJECT TO RIG AVAILABILITY. ESTIMATED TOTAL PAYMENTS OF US$100 MILLION, AFTER JOINT VENTURE RECOVERIES, HAVE BEEN INCLUDED IN THIS TABLE FOR THE PERIOD 2008 - 2009.

(3) DURING 2007, THE COMPANY AWARDED CONTRACTS FOR A DRILLING RIG AND FOR THE CONSTRUCTION OF WELLHEAD TOWERS IN CONNECTION WITH THE PLANNED OFFSHORE DEVELOPMENT IN GABON, OFFSHORE WEST AFRICA. ESTIMATED TOTAL PAYMENTS OF US$393 MILLION HAVE BEEN INCLUDED IN THIS TABLE FOR THE PERIOD 2008 - 2010.

(4) 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 2008 - 2012 REPRESENT THE MINIMUM REQUIRED EXPENDITURES TO MEET THESE OBLIGATIONS. ACTUAL EXPENDITURES IN ANY PARTICULAR YEAR MAY EXCEED THESE MINIMUM AMOUNTS.

(5) 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 $2,366 MILLION OF REVOLVING BANK CREDIT FACILITIES DUE TO THE EXTENDABLE NATURE OF THE FACILITIES.

(6) 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, 2007.

In addition to the amounts disclosed above, the Company has budgeted construction costs of approximately $1.7 billion to $1.9 billion for 2008 related to the planned completion of Phase 1 of the Horizon Project.

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, 2007, the Company retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule") and Ryder Scott Company ("Ryder Scott") to evaluate 100% of the Company's conventional proved, as well as proved and probable crude oil, NGLs and natural gas reserves(1) (3) and prepare Evaluation Reports on these reserves. Sproule evaluated the Company's North America conventional assets and Ryder Scott evaluated the international conventional assets. The Company has been granted an exemption from 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 reserve reconciliation 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 its Annual Report. 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 voluntary additional information, which is disclosed in the Company's Annual Information Form.

For the year ended December 31, 2007, the Company retained a qualified independent reserves evaluator, GLJ Petroleum Consultants ("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, NGL and natural gas reserves.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of Sproule, Ryder Scott 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.

Additional reserves disclosure is annually disclosed in the supplementary oil and gas information of the Company's Annual Report.

(1) CONVENTIONAL CRUDE OIL, NGLS AND NATURAL GAS INCLUDES ALL OF THE COMPANY'S LIGHT/MEDIUM, PRIMARY HEAVY, AND THERMAL CRUDE OIL, NATURAL GAS, COAL BED METHANE AND NGLS ACTIVITIES. IT DOES NOT INCLUDE THE COMPANY'S OIL SANDS MINING ASSETS.

(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. ONLY FUTURE DEVELOPMENT COSTS AND ASSOCIATED MATERIAL WELL ABANDONMENT LIABILITIES HAVE BEEN APPLIED.

(3) CONVENTIONAL CRUDE OIL, NGLS, AND NATURAL GAS RESERVES, NET OF ROYALTIES, ARE ESTIMATED USING ROYALTY REGULATIONS IN EFFECT AS OF DECEMBER 31, 2007. SIMILARLY, BITUMEN AND SYNTHETIC CRUDE OIL RESERVES, NET OF ROYALTIES, RELATING TO SURFACE MINEABLE OIL SAND PROJECTS ARE ESTIMATED USING ROYALTY REGULATIONS IN EFFECT AS OF DECEMBER 31, 2007. ROYALTY CHANGES PROPOSED BY THE GOVERNMENT OF ALBERTA WILL BE INCORPORATED IN THE RESERVES EVALUATION SHOULD THEY BE ENACTED.

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 synthetic crude oil. 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 insurance program to reduce risk to an acceptable level and to protect it against significant losses. 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 reviews 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. 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 minimizes credit risk by entering into financial derivatives with entities which are substantially all investment grade. 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 Using water-based, environmentally friendly drilling muds whenever possible;
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; and
o Minimizing produced water volumes onshore and offshore through cost-effective measures.

For 2007, the Company's capital expenditures included $71 million for abandonment expenditures (2006 - $75 million; 2005 - $46 million).

The Company's estimated undiscounted ARO at December 31, 2007 was as follows:

Estimated ARO, undiscounted ($ millions)	2007	2006
North America	$ 3,038	$ 2,826
North Sea	1,286	1,543
Offshore West Africa	102	128
	4,426	4,497
North Sea PRT recovery	(555)	(625)
	$ 3,871	$ 3,872

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 expected to result in an estimated PRT recovery of $555 million (2006 - $625 million; 2005 - $370 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 $3,871 million (2006 - $3,872 million).

GREENHOUSE GAS AND OTHER AIR EMISSIONS

The Company is concurrently 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 emission reductions 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 CO2e annually. In the UK, GHG regulations have been in effect since 2005. The Company has strategies in place to ensure compliance with any requirements currently 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, CO2 capture and sequestration in oil sands tailings, CO2 capture and storage in association with enhanced oil recovery, and participation in an industry initiative to promote an integrated CO2 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 participation of the Company and the industry 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 GAAP that have a significant impact on the financial results of the Company. Actual results could differ from those estimates, and those differences could 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 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 constant dollar pricing as required by the SEC. 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.

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 Company retains qualified independent reserves evaluators to evaluate the Company's proved, and proved and probable crude oil and natural gas reserves. In 2007, 100% of the Company's reserves were evaluated by qualified independent reserves evaluators.

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 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 could also result in a write-down 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 6.6%. 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 capital 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 could 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 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, currency and interest rate exposures. These derivative financial instruments are not intended for trading or speculative purposes.

Effective January 1, 2007, the Company adopted the new accounting standards relating to the accounting for and disclosure of financial instruments. The effects of adopting these standards on the Company's opening balance sheet are discussed in further detail in the "Risk Management Activities" section of this MD&A. All derivative financial instruments are recognized at estimated fair value on the consolidated balance sheet at each balance sheet date. The estimated fair value of derivative instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. However, these 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.

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 judgments 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 engineers and outside consultants. The judgments 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, 2007, 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 allow timely decisions regarding required disclosures.

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, 2007, 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 2007 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

While the Company believes that its disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance that they are effective, it recognizes that all internal control systems have inherent limitations. Because of its inherent limitations, the Company's internal control system 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 will adopt the following three new accounting 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 section also requires the disclosure of any externally-imposed capital requirements and compliance with those requirements. The section does not define capital. The section affects disclosures only and will 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 is not anticipated to have a material impact on the Company's financial statements.

FINANCIAL INSTRUMENTS
o 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 disclosures of 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 will not impact the Company's accounting for financial instruments.

In addition, the following standard was issued during 2008 and will be effective for the Company's year beginning on January 1, 2009, with earlier adoption permitted:

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. Adoption of the new standard may impact the Company's capitalization of certain costs during the development and start-up of large development projects.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

The CICA has confirmed that Canadian GAAP will be replaced in full with International Financial Reporting Standards as promulgated by the International Accounting Standards Board effective January 1, 2011.

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 2008 to average between 316,000 bbl/d and 366,000 bbl/d of crude oil and NGLs and between 1,429 mmcf/d and 1,513 mmcf/d of natural gas.

The forecasted capital expenditures in 2008 are currently expected to be as follows:

<TABLE>

($ millions)	2008 Forecast
<S>	<C>
CONVENTIONAL CRUDE OIL AND NATURAL GAS	
North America natural gas	$ 617
North America crude oil and NGLs	1,075
North Sea	231
Offshore West Africa	458
Property acquisitions, dispositions and midstream	390
	$ 2,771
HORIZON PROJECT	
Phase 1 - Construction (1)	$ 1,750 - 1,950
Phase 1 - Operating inventory and capital inventory	109
Phase 1 - Commissioning costs	184
Phase 2/3 - Tranche 2	439
Sustaining costs	19
Capitalized interest and other costs	381
	$ 2,882 - 3,082
TOTAL	$ 5,653 - 5,853

</TABLE>

(1) REVISED FORECASTED CAPITAL EXPENDITURES.

NORTH AMERICA NATURAL GAS

The 2008 North America natural gas drilling program is highlighted by the continued high-grading of the Company's natural gas asset base as follows:

<TABLE>

(Number of wells)	2008 Forecast
<S>	<C>
Coal bed methane and shallow natural gas	161
Conventional natural gas	104
Cardium natural gas	14
Deep natural gas	32
Foothills natural gas	3
Total	314

</TABLE>

The Company has reduced 2008 natural gas drilling in Alberta due to the anticipated future impact of royalty changes effective 2009.

NORTH AMERICA CRUDE OIL AND NGLS

The 2008 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:

<TABLE>

(Number of wells)	2008 Forecast
<S>	<C>
Conventional primary heavy crude oil	311
Thermal heavy crude oil	32
Light crude oil	78
Pelican Lake crude oil	105
Total	526

</TABLE>

HORIZON PROJECT

The Horizon Project is targeting first crude oil in the third quarter of 2008. Phase 1 construction capital is budgeted to be approximately $1.7 billion to $1.9 billion in 2008, representing a cost to completion forecast range of 25% to 28% over the original $6.8 billion estimate.

NORTH SEA

The 2008 capital forecast for the North Sea includes drilling 4 net platform wells while continuing the successful workover and recompletion program.

OFFSHORE WEST AFRICA

The 2008 capital forecast for Offshore West Africa includes re-completing 2 wells at Baobab and targeted first oil at Olowi in late 2008.

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 2007, excluding mark-to-market gains (losses) on risk management activities, 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; all other variables are held constant.

<TABLE>

	CASH FLOW FROM OPERATIONS ($ MILLIONS)	CASH FLOW FROM OPERATIONS (PER COMMON SHARE, BASIC)	NET EARNINGS ($ MILLIONS)	NET EARNINGS (PER COMMON SHARE, BASIC)
<S>	<C>	<C>	<C>	<C>
PRICE CHANGES				
Crude oil - WTI US$1.00/bbl (1)				
Excluding financial derivatives	$ 96	$ 0.18	$ 70	$ 0.13
Including financial derivatives	$ 21	$ 0.04	$ 17	$ 0.03
Natural gas - AECO C$0.10/mcf (1)				
Excluding financial derivatives	$ 41	$ 0.08	$ 29	$ 0.05
Including financial derivatives	$ 33	$ 0.06	$ 23	$ 0.04
VOLUME CHANGES				
Crude oil - 10,000 bbl/d	$ 132	$ 0.25	$ 70	$ 0.13
Natural gas - 10 mmcf/d	$ 16	$ 0.03	$ 6	$ 0.01
FOREIGN CURRENCY RATE CHANGE				
$0.01 change in US$ (1)				
Including financial derivatives	$ 73 - 74	$ 0.13 - 0.14	$ 31 - 32	$ 0.06
INTEREST RATE CHANGE - 1%	$ 38	$ 0.07	$ 38	$ 0.07

</TABLE>

(1) FOR DETAILS OF FINANCIAL INSTRUMENTS IN PLACE, REFER TO NOTE 12 TO THE COMPANY'S AUDITED ANNUAL CONSOLIDATED FINANCIAL STATEMENTS AS AT DECEMBER 31, 2007.

<TABLE>
<CAPTION>
DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

Q1	Q2	Q3	Q4	2007	2006	2005
<S>	<C>	<C>	<C>	<C>	<C>	<C>
CRUDE OIL AND NGLS (BBL/D)						
North America	237,489	240,420	252,095	256,843	246,779	235,253	221,669
North Sea	61,869	57,286	52,013	52,709	55,933	60,056	68,593
Offshore West Africa	27,643	29,788	28,954	27,688	28,520	36,689	22,906
Total	327,001	327,494	333,062	337,240	331,232	331,998	313,168
NATURAL GAS (MMCF/D)							
North America	1,694	1,696	1,622	1,562	1,643	1,468	1,416
North Sea	15	15	10	13	13	15	19
Offshore West Africa	8	11	15	14	12	9	4
Total	1,717	1,722	1,647	1,589	1,668	1,492	1,439
BARRELS OF OIL EQUIVALENT (BOE/D)							
North America	519,700	523,037	522,427	517,101	520,564	479,891	457,695
North Sea	64,370	59,758	53,597	54,825	58,099	62,558	71,651
Offshore West Africa	29,044	31,666	31,460	29,982	30,543	38,275	23,614
Total	613,114	614,461	607,484	601,908	609,206	580,724	552,960

PER UNIT RESULTS (1)

Q1	Q2	Q3	Q4	2007	2006	2005
CRUDE OIL AND NGLS ($/BBL)						
Sales price (2)	$ 51.71	$ 53.74	$ 58.10	$ 58.03	$ 55.45	$ 53.65	$ 46.86
Royalties	4.92	5.46	6.65	6.66	5.94	4.48	3.97
Production expense	13.81	15.01	13.13	11.53	13.34	12.29	11.17
Netback	$ 32.98	$ 33.27	$ 38.32	$ 39.84	$ 36.17	$ 36.88	$ 31.72
NATURAL GAS ($/MCF)							
Sales price (2)	$ 7.74	$ 7.44	$ 5.87	$ 6.28	$ 6.85	$ 6.72	$ 8.57
Royalties	1.48	1.10	0.89	0.94	1.11	1.29	1.75
Production expense	0.97	0.89	0.88	0.91	0.91	0.82	0.73
Netback	$ 5.29	$ 5.45	$ 4.10	$ 4.43	$ 4.83	$ 4.61	$ 6.09
BARRELS OF OIL EQUIVALENT ($/BOE)							
Sales price (2)	$ 49.32	$ 49.70	$ 47.96	$ 49.23	$ 49.05	$ 47.92	$ 48.77
Royalties	6.76	5.99	6.07	6.21	6.26	5.89	6.82
Production expense	10.10	10.44	9.62	8.85	9.75	9.14	8.21
Netback	$ 32.46	$ 33.27	$ 32.27	$ 34.17	$ 33.04	$ 32.89	$ 33.74

</TABLE>
(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.

<TABLE>
<CAPTION>
NETBACK ANALYSIS

($/boe) (1)	2007	2006	2005
<S>	<C>	<C>	<C>
Sales price (2)	$ 49.05	$ 47.92	$ 48.77
Royalties	6.26	5.89	6.82
Production expense (3)	9.75	9.14	8.21
NETBACK	33.04	32.89	33.74
Midstream contribution (3)	(0.23)	(0.23)	(0.26)
Administration	0.93	0.85	0.75
Interest, net	1.24	0.66	0.74
Realized risk management loss	0.73	6.27	5.13
Realized foreign exchange loss (gain)	0.24	(0.06)	(0.15)
Taxes other than income tax - current	0.54	1.04	1.01
Current income tax - North America	0.43	0.68	0.50
Current income tax - North Sea	0.95	0.14	0.77
Current income tax - Offshore West Africa	0.33	0.23	0.17
CASH FLOW	$ 27.88	$ 23.31	$ 25.08

</TABLE>
(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.

<TABLE>
<CAPTION>
TRADING AND SHARE STATISTICS

Q1	Q2	Q3	Q4	2007	2006
<S>	<C>	<C>	<C>	<C>	<C>
TSX - C$					
Trading Volume (thousands)	117,164	94,089	100,950	116,831	429,034	508,935
Share Price ($/share)						
High	$ 65.50	$ 74.99	$ 80.02	$ 79.91	$ 80.02	$ 73.91
Low	$ 52.45	$ 63.71	$ 65.43	$ 64.24	$ 52.45	$ 45.49
Close	$ 63.75	$ 70.78	$ 75.56	$ 72.58	$ 72.58	$ 62.15
Market capitalization as at December 31 ($ millions)				$ 39,174	$ 33,431	
Shares outstanding (thousands)				539,729	537,903	
NYSE - US$						
Trading Volume (thousands)	128,543	93,086	118,315	146,322	486,266	401,909
Share Price ($/share)						
High	$ 56.62	$ 69.97	$ 78.90	$ 87.17	$ 87.17	$ 64.38
Low	$ 44.56	$ 55.07	$ 60.70	$ 63.52	$ 44.56	$ 40.29
Close	$ 55.19	$ 66.35	$ 75.75	$ 73.14	$ 73.14	$ 53.23
Market Capitalization as at December 31($ millions)				$ 39,476	$ 28,633	
Shares outstanding (thousands)				539,729	537,903	

</TABLE>

ADDITIONAL DISCLOSURE

DISCLOSURE CONTROLS AND PROCEDURES

As of the end of the registrant's fiscal year ended December 31, 2007, 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, 2007, 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, 2007, filed as part of this Annual Report on Form 40-F.

CHANGES IN INTERNAL CONTROLS OVER FINANCIAL REPORTING

During the fiscal year ended December 31, 2007, there were no changes in Canadian Natural's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, Canadian Natural's internal controls 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. In 2007 the Nominating and Corporate Governance Committee reviewed and recommended to the Board revisions relating to clarification on insider trading, communication and disclosure, communication with electronic mediums, Staff participating in government and political activities, and Canadian Natural's Human Rights Statement which were subsequently approved by the Board of Directors.

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, 2007 and December 31, 2006, 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 $2,729,315 for 2007 and were $3,126,287 for 2006.

AUDIT-RELATED FEES

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2007 and December 31, 2006, for audit-related services by PwC including debt covenant compliance and Crown Royalty Statements, were $164,000 for 2007 and were $121,353 for 2006. 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, 2007 and December 31, 2006, for professional services rendered by PwC for tax-related services related to expatriate personal tax and compliance as well as other corporate tax return matters provided in 2007 were $154,459 for 2007 and were $134,025 for 2006. 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, 2007 and December 31, 2006 for other services were $9,440 for 2007 and were $9,516 for 2006. The fees for other services paid in 2007 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 2007.

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, 2007, filed herewith, under the caption "Commitments and Off Balance Sheet Arrangements".

CONTRACTUAL OBLIGATIONS

In the normal course of business, Canadian Natural has entered into various commitments that will have an impact on its future operations. These commitments primarily relate to debt repayments; operating leases relating to Floating Production, Storage and Offsite vessels ("FPSOs"), drilling rigs and office space; and firm commitments for gathering, processing and transmission services; as well as expenditures relating to asset retirement obligations ("ARO"). As at December 31, 2007, no entities were consolidated under CICA Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes Canadian Natural's commitments as at December 31, 2007:

<TABLE>

($ millions)	2008	2009	2010	2011	2012	Thereafter
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Product transportation and pipeline	$ 232	$ 151	$ 137	$ 109	$ 91	$ 972
Offshore equipment operating lease (1)	$ 114	$ 129	$ 113	$ 111	$ 90	$ 387
Offshore drilling (2) (3)	$ 267	$ 185	$ 39	$ -	$ -	$ -
Asset retirement obligations (4)	$ 33	$ 4	$ 5	$ 4	$ 4	$ 4,376
Long-term debt (5)	$ 39	$ 2,361	$ 400	$ 395	$ 346	$ 5,098
Interest expense (6)	$ 612	$ 590	$ 487	$ 465	$ 374	$ 4,338
Office lease	$ 26	$ 28	$ 28	$ 22	$ 3	$ -
Electricity and other	$ 166	$ 173	$ 25	$ 4	$ -	$ -

</TABLE>

(1) OFFSHORE EQUIPMENT OPERATING LEASES ARE PRIMARILY COMPRISED OF OBLIGATIONS RELATED TO FPSOS. DURING 2006, CANADIAN NATURAL ENTERED INTO AN AGREEMENT TO LEASE AN ADDITIONAL FPSO COMMENCING IN 2008, IN CONNECTION WITH THE PLANNED OFFSHORE DEVELOPMENT IN GABON, OFFSHORE WEST AFRICA. DURING THE INITIAL TERM, THE TOTAL ANNUAL PAYMENTS FOR THE GABON FPSO ARE ESTIMATED TO BE US$50 MILLION.

(2) DURING 2007, CANADIAN NATURAL ENTERED INTO A ONE-YEAR AGREEMENT FOR OFFSHORE DRILLING SERVICES RELATED TO THE BAOBAB FIELD IN COTE D'IVOIRE, OFFSHORE WEST AFRICA. THE AGREEMENT IS SCHEDULED TO COMMENCE IN 2008, SUBJECT TO RIG AVAILABILITY. ESTIMATED TOTAL PAYMENTS OF US$100 MILLION, AFTER JOINT VENTURE RECOVERIES, HAVE BEEN INCLUDED IN THIS TABLE FOR THE PERIOD 2008 - 2009.

(3) DURING 2007, CANADIAN NATURAL AWARDED CONTRACTS FOR A DRILLING RIG AND FOR THE CONSTRUCTION OF WELLHEAD TOWERS IN CONNECTION WITH THE PLANNED OFFSHORE DEVELOPMENT IN GABON, OFFSHORE WEST AFRICA. ESTIMATED TOTAL PAYMENTS OF US$393 MILLION HAVE BEEN INCLUDED IN THIS TABLE FOR THE PERIOD 2008 - 2010.

(4) 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 2008 - 2012 REPRESENT THE MINIMUM REQUIRED EXPENDITURES TO MEET THESE OBLIGATIONS. ACTUAL EXPENDITURES IN ANY PARTICULAR YEAR MAY EXCEED THESE MINIMUM AMOUNTS.

(5) 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 $2,366 MILLION OF REVOLVING BANK CREDIT FACILITIES DUE TO THE EXTENDABLE NATURE OF THE FACILITIES.

(6) 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, 2007.

In addition to the amounts disclosed above, Canadian Natural has budgeted construction costs of approximately $1.7 billion to $1.9 billion for 2008 related to the planned completion of Phase 1 of the Horizon Oil Sands Project.

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, 2007, 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 27th day of March, 2008.

CANADIAN NATURAL RESOURCES LIMITED

By: /S/ 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, 2007.

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 Ryder Scott Company, independent petroleum engineering consultants.

9. Consent of GLJ Petroleum Consultants Ltd., independent petroleum engineering consultants.