CANADIAN NATURAL RESOURCES LTD
Form 40-F
April 05, 2006

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, 2005 Commission File Number: 1-8795

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

ALBERTA
(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 Toronto 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.

536,347,796 Common Shares outstanding as of December 31, 2005

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. 333-104919) under the Securities Act of 1933.

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, 2005.

B. AUDITED ANNUAL FINANCIAL STATEMENTS

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2005 and 2004, 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 15 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, 2005.

SUPPLEMENTARY OIL & GAS INFORMATION

For Canadian Natural's Supplementary Oil & Gas Information for the year ended December 31, 2005, see Exhibit 1 of this Annual Report on Form 40-F.

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C A N A D I A N   N A T U R A L   R E S O U R C E S   L I M I T E D

ANNUAL INFORMATION FORM

MARCH 29, 2006

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CURRENCY

Unless otherwise indicated, all dollar figures stated in this Annual Information Form represent Canadian dollars.

DEFINITIONS

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

"ARTC" means Alberta Royalty Tax Credit.

"BBL" or "BARREL" means 34.972 Imperial gallons or 42 U.S. gallons.

"BCF" means one billion cubic feet.

"BBL/D" means barrels per day.

"BOE" means natural gas is converted to oil equivalent at the rate of six thousand cubic feet equals one barrel of oil equivalent.

"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.

"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 unproven territory with the intention to discover commercial quantities of crude oil or natural gas.

"FPSO" means a Floating Production, Storage and Off-take vessel.

"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.

"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" a well that is not dry.

"SAGD" means steam-assisted gravity drainage.

"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.

"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 incorporated herein by reference may constitute "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such because of the context of the statements including words such as "believes", "anticipates", "expects", "plans", "estimates", or words of a similar nature.

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: the general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; the foreign currency exchange rates; the economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists or insurgent groups or other conflict including conflict between states; the industry capacity; the ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition; the availability and cost of seismic, drilling and other equipment; the ability of the Company to complete its capital programs; the ability of the Company to transport its products to market; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the ability of the Company to attract the necessary labour required to build its projects; the operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; the availability and cost of financing; the success of exploration and development activities; the timing and success of integrating the business and operations of acquired companies; the production levels; the uncertainty of reserve estimates; the actions by governmental authorities; the government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); the asset retirement obligations; and other circumstances affecting revenues and expenses. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent and management's course of action would depend upon its assessment of the future considering all information then available.

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.

Readers are cautioned that the foregoing list of important factors is not exhaustive. 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 were 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 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, 2005, Canadian Natural retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule") and Ryder Scott Company ("Ryder Scott"), to evaluate 100% of the Company's conventional proved and probable crude oil, natural gas liquid ("NGL") and natural gas reserves and prepare Evaluation Reports on these reserves. Sproule evaluated the Company's North American conventional assets and Ryder Scott evaluated its conventional international assets. The Company has been granted an exemption from the 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 United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. There are two principal differences between the two standards. The first is the additional 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 Company has disclosed conventional proved reserves and the Standardized Measure of discounted future net cash flows using constant prices and costs as mandated by the SEC in the supplementary oil and gas information section of its Annual Report. The Company has also elected to provide the net present value of these same conventional proved reserves as well as the conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. In addition to the constant price and cost scenario, the Company has also elected to provide both conventional proved and conventional proved and probable reserves, as well as the net present value of these reserves, using forecast prices and costs as voluntary additional information.

Reserves and net present values of these reserves presented for years prior to 2003 were evaluated in accordance with the standards of National Policy 2-B, which has now been replaced by NI 51-101. The stated reserves were reasonably evaluated as economically productive using year-end costs and prices escalated at appropriate rates throughout the productive life of the properties.

For the year ended December 31, 2005, 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 Oil Sands 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 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, NGL 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 includes references to financial measures commonly used in the oil and gas industry, such as cash flow, adjusted net earnings and EBITDA (net earnings before interest, taxes, depreciation depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activity). 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 the performance of the Company. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance.

THE 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.

The significant 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 (Gabon) Limited	Bahamas
Horizon Construction Management Ltd.	Alberta
Renata Resources Inc.	Alberta

Canadian Natural, as the managing partner, CNR (ECHO) Resources Inc. and Renata Resources Inc. are the partners of Canadian Natural Resources, a general partnership. Canadian Natural Resources, as the managing partner, CNR (ECHO) Resources Inc., Renata Resources Inc., and Canadian Natural 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. The Company also has a 15 per cent 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 per cent partnership interest. Canadian Natural, as the managing partner, and Renata Resources Inc. are the partners of Canadian Natural Resources 2005 Partnership, a general partnership which holds certain natural gas facilities situated in Alberta. Canadian Natural, as the managing partner, and 1081840 Alberta Ltd. are the partners of 1081840 Alberta Partnership, which holds certain crude oil and natural gas properties of the Company.

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 natural gas.

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 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, 2005 the Company had 2,580 permanent employees in North America and 317 permanent employees in its international operations.

During 2003, the Company completed 111 transactions in the normal course to acquire additional interests in crude oil and natural gas properties at an aggregate expenditure of $355.3 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 non-operated properties not located in the Company's core regions for proceeds of $19.3 million.

In February 2004, the Company completed the acquisition of certain resource properties located in East Central Alberta and Saskatchewan (collectively known as the Petrovera Partnership) for aggregate consideration of $701 million. In a separate transaction, the Company sold specific resource properties in the Petrovera Partnership, representing approximately one third of the total acquisition, to another independent producer for proceeds of $234 million, resulting in a net cost of $467 million for the retained properties. The net production from the working interests at the time of the acquisition retained by the Company was approximately 27.5 mbbl/d of heavy crude oil and 9 mmcf/d of natural gas together with volumes associated with royalty interests of 1.2 mbbl/d of heavy oil and 2 mmcf/d of natural gas. All of the retained properties are situated in the Company's core region of Northern Plains.

In April 2004, the Company completed an acquisition of certain crude oil and natural gas properties located in Northeast British Columbia and Northwest Alberta for consideration of $280 million. The properties at the time of acquisition were producing approximately 68 mmcf/d of natural gas and 200 bbl/d of light crude oil and NGLs and contained over 415 thousand acres of developed and undeveloped land. The properties included a further interest in the Ladyfern natural gas field. The portion of the Ladyfern field included in the acquisition included production of approximately 50 mmcf/d of natural gas. As part of this acquisition, the Company also acquired undeveloped acreage in the Foothills area of Alberta and British Columbia. This area is characterized by large, undeveloped pools with significant natural gas potential in deeper zones and has added a new exploration base in the Alberta Foothills, complementing the Company's existing holdings and production base in the British Columbia Foothills.

In the third quarter of 2004, the Company's wholly owned subsidiary CNR International (U.K.) Limited acquired certain crude oil and natural gas properties in the central North Sea. The acquired properties comprise operated interests in T-Block (Tiffany, Toni and Thelma fields) and B-Block (Balmoral, Stirling and Glamis fields) together with associated production facilities and adjacent exploration acreage.

On December 1, 2004, the Company issued US $350.0 million of 10 year 4.90 per cent unsecured notes maturing December 1, 2014 and US $350.0 million of 30 year 5.85 per cent unsecured notes maturing February 1, 2035 pursuant to a short form shelf prospectus dated May 8, 2003.

In December 2004, the Company acquired certain crude oil and natural gas properties located in Alberta and British Columbia, for an aggregate cash consideration of approximately $703 million, net of proceeds received from an agreement to concurrently dispose of a portion of such properties for approximately $50 million and cash flows realized from the effective date of September 1, 2004. At the time of the acquisition production from the properties acquired by Canadian Natural, after the above noted disposition, was estimated at 105 mmcf/d of natural gas and 7.5 mbbl/d of light crude oil and NGLs being approximately 25,000 boe/d. The acquisition included over 510,000 net acres of undeveloped land. The vast majority of the acquired properties is located in the Company's core regions and extends its Northern Plains core region into the light crude oil operating area of Dawson.

During 2004, the Company completed 109 transactions (including the four acquisitions mentioned above) in the normal course to acquire additional interests in crude oil and natural gas properties at an aggregate net expenditure of $1.371 billion (excluding the Petrovera Partnership acquisition

described above). 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 non-operated properties not located in the Company's core regions for proceeds of $7 million.

In February 2005, the Board of Directors of the Company approved Phase 1 of the Horizon Oil Sands Project ("Horizon Project"). The Horizon Project is designed as a phased development and includes the mining of bitumen combined with an onsite upgrader. Phase 1 production is planned to begin in the second half of 2008 at 110 mbbl/d of 34(degree) API light, sweet synthetic crude oil ("SCO"). Phase 2 would increase production to 155 mbbl/d of SCO in 2010. Phase 3 would further increase production to 232 mbbl/d of SCO in 2012. 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.

Based upon stratigraphic drilling 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 37 years of production without the declines normally associated with petroleum operations. GLJ Petroleum Consultants ("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 3.4 billion barrels of gross proved and probable bitumen 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 is expected to begin in 2006 and will be fully operational by mid 2008 to coincide with first production at the Horizon Project. See below "Horizon Oil Sands 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, the trust units were sold to an underwriting group pursuant to an agreement for a net gain of approximately $11 million.

On June 1, 2005, the Company issued $400 million of 10-year 4.95 per cent unsecured notes maturing June 1, 2015 pursuant to a short form shelf prospectus for the issuance of medium term notes in Canada dated August 1, 2003. In January 2006 the Company issued a further $400 million of 4.50 per cent unsecured notes maturing January 23, 2013 as the first issuance under the short form Canadian base shelf prospectus dated August 29, 2005, which allows for the issuance of debt securities in an aggregate principal amount of up to C$2 billion.

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.

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, prevention of waste and other activities.

The Company's Canadian properties are located in Alberta, British Columbia, Saskatchewan, Manitoba and the Northwest 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 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 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.

In addition to government royalties, the Company is subject to federal and provincial income taxes in Canada at a combined rate of approximately 38.1 per cent after allowable deductions.

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 per cent 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 per cent. 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 CT charge of 10 per cent, charged on the same profits as calculated for `normal' CT but excluding any deduction for financing costs, was added to the current 30 per cent CT charge. Also the deduction for expenditures on capital items was changed from 25 per cent per annum to 100 per cent in the year incurred. In December 2005, the UK Chancellor of the Exchequer announced an increase to the Supplementary CT from 10 per cent to 20 per cent, effective January 1, 2006.

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, 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 (See "Principal Crude Oil and Natural Gas Properties - Offshore West Africa").

In October 2005, Canadian Natural completed the acquisition of the permit to develop the Olowi Field, offshore Gabon. 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.

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

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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. 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, profitability 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 27 percent of the Company's 2005 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.

Canadian Natural anticipates that changes in environmental legislation may require, among other things, reductions in emissions to the air from its operations which may result in increased capital expenditures. Future changes in environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on the Company's financial condition or results of operations.

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. Canadian Natural's liability, property and business interruption insurance may not provide adequate coverage in certain unforeseen 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 the United States or Canada.

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 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, NGL and natural gas reserves and the future net cash flow there from 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, NGL 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 there from, 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 otherwise. 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.

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 environmental compliance audit and inspection program of its operating facilities; an aggressive 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; progressive due diligence related to groundwater monitoring; prevention of and reclamation of spill sites; greenhouse gas ("GHG") reduction; and flaring and venting reduction. Canadian Natural participates in both the Canadian federal and provincial regulated GHG emissions reporting for facilities with GHG emissions greater than 100 thousand tonnes of CO2 equivalent per year. 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 our overall goal of a net reduction of GHG emissions per unit of production.

The costs incurred by the Company for compliance with environmental matters and site restoration amounted to less than 3 per cent of the total exploration and development expenditures incurred by the Company in each of the years ended December 31, 2005, 2004 and 2003.

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 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 43 per cent of 2005 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 crude oil and NGLs, representing 26 per cent of 2005 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 27 per cent of 2005 production. Other heavy crude oil, which accounts for 4 per cent of 2005 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 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 crude 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 is expected to deliver approximately 37 years of synthetic crude oil production.

As a result of the Company's core undeveloped land base of 10.9 million net acres in western Canada, its international concessions and the Alberta oil sands leases, 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, 2005. The information reflects the working interests owned by the Company.

	2005 AVERAGE DAILY PRODUCTION RATES		YEAR ENDED DECEMBER 31, 2005	MAJOR INFRASTRUCT AS AT DECEMBER 31,
REGION	CRUDE OIL & NGLs mbbl	NATURAL GAS mmcf	UNDEVELOPED ACREAGE (thousands)	BATTERIES/ COMPRESSORS & PLA PLATFORMS /FPSO
NORTH AMERICA				
Northeast B. C.	6.7	434.4	2,027	1/9/-/-
Northwest Alberta	13.5	403.4	1,507	-/8/-/-
Northern Plains	181.8	419.2	6,594	12/6/-/-
Southern Plains	10.7	155.4	621	-/2/-/-
Southeast Saskatchewan	8.8	3.1	82	-/-/-/-
Non - core regions	0.2	0.8	236	-/-/-/-
Horizon Oil Sands	-	-	115	-/-/-/-
INTERNATIONAL				
North Sea UK Sector	68.6	18.4	352	-/-/6/1
Offshore West Africa				
Cote d'Ivoire	22.9	4.1	274	-/-/0/2
Gabon	-	-	152	-/-/-/-
Non - core regions				
South Africa	-		4,002	-/-/-/-
TOTAL	313.2	1438.8	15,963	13/25/6/3

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 up to December 31, 2005 by geographic region:

2005

	NET EXPLORATORY			NET DE
	PRODUCTIVE	DRY HOLES	TOTAL	PRODUCTIVE
CANADA				
Northeast B. C.	32.1	7.2	39.3	179.9
Northwest Alberta	29.9	9.0	38.9	135.2
Northern Plains	63.5	11.5	75.0	671.4
Southern Plains	50.6	5.0	55.6	294.9
Southeast Saskatchewan	1.0	-	1.0	43.0
Non - core regions	-	-	-	0.3
NORTH SEA UK SECTOR	-	0.8	0.8	11.5
OFFSHORE WEST AFRICA				
Cote d'Ivoire	-	0.6	0.6	3.5
TOTAL	177.1	34.1	211.2	1339.7

2004

	NET EXPLORATORY			NET DE
	PRODUCTIVE	DRY HOLES	TOTAL	PRODUCTIVE
CANADA				
Northeast B. C.	23.8	6.2	30.0	146.8
Northwest Alberta	42.8	7.6	50.4	100.4
Northern Plains	116.6	26.6	143.2	333.8
Southern Plains	18.5	7.0	25.5	209.9
Southeast Saskatchewan	-	-	-	12.5
Non - core regions	-	-	-	0.5
NORTH SEA UK SECTOR	-	2.0	2.0	9.2

OFFSHORE WEST AFRICA				
Cote d'Ivoire	-	0.7	0.7	2.3
TOTAL	201.7	50.1	251.8	815.4

	2003			
		NET EXPLORATORY		NET DE
	PRODUCTIVE	DRY HOLES	TOTAL	PRODUCTIVE D
CANADA				
Northeast B. C.	15.5	13.3	28.8	67.8
Northwest Alberta	31.7	11.8	43.5	69.9
Northern Plains	57.5	26.6	84.1	531.6
Southern Plains	33.0	4.0	37.0	387.9
Southeast Saskatchewan	-	-	-	26.9
Non - core regions	-	-	-	0.4
NORTH SEA UK SECTOR	-	1.0	1.0	11.1
OFFSHORE WEST AFRICA				
Cote d'Ivoire	0.7	-	0.7	0.7
Angola	-	0.6	0.6	-
TOTAL	138.4	57.3	195.7	1,096.3

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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, 2005:

	NATURAL GAS WELLS		CRUDE OIL WELLS		
	GROSS	NET	GROSS	NET	GROS
CANADA					
Northeast B. C.	1,177	983.7	278	204.4	
Northwest Alberta	1,196	948.7	195	140.1	

Northern Plains	3,502	2,923.7	5,799	5,291.9
Southern Plains	4,260	3,698.5	1,026	922.0
Southeast Saskatchewan	-	-	1,092	768.0
Non - core regions	837	334.3	1,483	470.0
UNITED STATES	4	0.5	2	0.2
NORTH SEA UK SECTOR	4	0.3	118	98.4
OFFSHORE WEST AFRICA				
Cote d'Ivoire	-	-	15	8.7
TOTAL	10,980	8,889.7	10,008	7,903.7

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

NORTHEAST BRITISH COLUMBIA

[GRAPHIC OMITTED]

This region comprises lands from Fort St. John, British Columbia to the northern border as well as the eastern border of British Columbia. Similar geological attributes extend throughout the region, producing light crude oil, NGLs and natural gas. The Company holds working interests ranging up to 100 per cent and averaging 77 per cent in 3,776,051 gross (2,895,451 net) acres of producing and undeveloped land in the region.

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Crude oil reserves are found primarily in the Halfway or lower Halfway formation, while natural gas and associated NGLs are found in numerous zones at depths reaching approximately 2,500 vertical meters. In the southern portion of the region, the Company owns natural gas producing and undeveloped lands in which the productive zones are at deeper depths up to 3,500 meters. The exploration strategy focuses on comprehensive evaluation through two-dimensional seismic, three-dimensional seismic and targeting economic geological areas close to existing infrastructure. Natural gas production from the region averaged 434.4 mmcf/d in 2005 compared to the average of 437.3 mmcf/d in 2004. Crude oil and NGLs production was steady at to 6.7 thousand bbl/d in 2005 from an average of 6.8 thousand bbl/d in 2004.

During 2005, the Company developed a new exploration and development program 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 thousand cubic feet per day. In combination with the Company's extensive land base and the recently reduced royalty rates in British Columbia, this shallow gas drilling program will add to the Company's opportunities in this region.

During 2005, the Company drilled 10.9 (2004- 3.6) net crude oil wells, 201.1 (2004 - 167.0) net natural gas wells, 1.0 (2004 - 1.0) net stratigraphic/service wells and 28.3 (2004 - 20.6) net dry wells on its lands in this region for a total of 241.3 (2004 - 192.2) net wells. The Company held an average 85.6 per cent working interest in these wells.

NORTHWEST ALBERTA

[GRAPHIC OMITTED]

The Company holds working interests ranging up to 100 per cent and averaging 76 per cent in 2,809,179 gross (2,128,874 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 holdings in the region were obtained through the Plan of Arrangement in 2002, which facilitated the acquisition of RAX. This region contains exceptional exploration and exploitation opportunities as well as substantial available capacity within an extensively 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 southern portion provides a significant opportunity in the regionally extensive Cretaceous Cardium zone. The Cardium is a complex, tight natural gas reservoir where high productivity may be achieved due to greater matrix porosity or natural fracturing.

Natural gas production from the region averaged 403.4 mmcf/d in 2005 compared to an average of 303.2 mmcf/d in 2004. Crude oil and NGLs production was steady at 13.5 thousand bbl/d in 2005 from 10.9 thousand bbl/d in 2004.

During 2005, the Company drilled 12.9 (2004-5.8) net crude oil wells, 152.4 (2004-137.5) net natural gas wells, 0.7 (2004 - 1.5) net stratigraphic/service wells, and 16.3 (2004-11.5) net dry wells on its lands in this region for a total of 182.3 (2004-156.3) net wells. The Company held an average 82.1 per cent working interest in these wells.

NORTHERN PLAINS

[GRAPHIC OMITTED]

The Company holds working interests ranging up to 100 per cent and averaging 84 per cent in 11,608,488 gross (9,806,002 net) acres of producing and undeveloped land in the region located just south of Edmonton north to Fort McMurray and from the northwest Alberta border 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 419.2 mmcf/d in 2005 compared to 429.9 mmcf/d in 2004. Crude oil and NGLs production from this region increased to 181.8 thousand bbl/d in 2005 from 166.3 thousand bbl/d in 2004. 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 February 2004, the Company purchased the Petrovera Partnership which added additional properties in this region. Approximately one third of the total acquisition was sold to another independent producer. The properties that were retained further consolidated the Company's position in the area.

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Natural gas in this region is produced from shallow, low-risk, multi-zone prospects and more recently from the Horseshoe Canyon coal bed methane ("CBM"). The Company targets low-risk exploration and development opportunities and plans to expand its commercial CBM project. During 2005, CBM development drilling included 42 net wells and the Company has an inventory of over 500 net Horseshoe Canyon CBM locations.

In the area near Lloydminster, Alberta, reserves of heavy crude oil (averaging 12(Degree)-14(degree) API) and natural gas are produced through conventional vertical, slant and horizontal well bores from a number of productive horizons up to 1,000 meters deep. The energy required to flow the heavy crude oil to the wellbore in this type of heavy crude oil reservoir comes from solution gas. The crude oil viscosity and the reservoir quality will determine the amount of crude oil produced from the reservoir, which will vary from 3 to 20 per cent 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.

In the area around Elk Point, Ranger owned significant land and production in this region, with much of its land contiguous to the Company's holdings. With the operations combined in 2000, development in the region became more effective and provided opportunities for cost savings. As part of the acquisition of Ranger, the Company also acquired a 50 per cent interest in the ECHO Pipeline system, a crude oil transportation pipeline; and, in 2001 the Company acquired the remaining 50 per cent. The pipeline was extended north to the Company operated Beartrap field during 2001, enhancing further development of the Company's extensive holdings in the area. This pipeline was capable of transporting 57 thousand 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 thousand 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. The ECHO Pipeline system permits the Company to transport approximately 80 per cent of its heavy crude oil to the international mainline liquids pipelines.

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 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 thousand bbl/d of crude oil and a 50 per cent 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. In 2000, the Company successfully converted and tested two existing pads of wells from low-pressure steaming to high-pressure steaming. This conversion increased average production at the 20 existing wells from 100 to 190 barrels of crude oil per day per well. An additional 24 wells were drilled using the high-pressure steam process with initial production averaging 600 barrels of crude oil per day per well. These results have confirmed the benefits of converting the Primrose field to high-pressure steaming. In 2001, the Company received regulatory approval to convert an additional six low-pressure cyclic pads to high-pressure cyclic pads, and in 2002 received approval to apply

high-pressure steam methodologies throughout the field. Canadian Natural drilled 58 high-pressure wells in 2004. Additional development of the leases will be undertaken in phases over the next several years. The Company, in 2004, started to proceed with its Primrose North expansion project, which was effectively completed in 2005 with total capital expenditures of approximately $300 million incurred. The Primrose North expansion entails a remote steam treating facility and additional high pressure 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 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 expects construction to begin in 2007, with the first steam scheduled for January 2009. A SAGD heavy oil project in which the Company holds a 50 per cent interest is also in operation in the Saskatchewan portion of this region.

Included in the northern part of this region, approximately 200 miles north of Edmonton, are the Company's holdings at Pelican Lake; generally having a 100 per cent ownership rate by the Company. These lands contain reserves of 12(Degree)-17(Degree) API heavy crude oil. Operating costs are low due to the absence of sand production and 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 future economic development of the large crude oil pool located on the lands. The Company holds and controls approximately 75 percent of the known crude oil pool in this area.

This field contains approximately three billion barrels of original oil-in-place but is only expected to achieve a 5 percent recovery factor using existing primary technologies 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 enhance the waterflood scheme, in the second quarter of 2005, the Company installed facilities for a polymer flood pilot test. Initial behaviour of the polymer flood pilot test has been positive, however definitive conclusions regarding the feasibility of the program will not be known until late 2006 or early 2007. In advance of the pilot test results, preparations for commercial polymer flood have commenced including source water development and advance ordering of some of the long lead time equipment.

During 2005, the Company drilled 536.1 (2004 - 287.0) net crude oil wells, 198.9 (2004 - 163.4) net natural gas wells, 108.9 (2004 - 112.0) net stratigraphic/service wells, and 63.4 (2004 - 49.8) net dry wells for a total of 907.3 (2004 - 612.2) net wells. The Company's average working interest in these wells was 91.7 per cent.

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SOUTHERN PLAINS AND SOUTHEAST SASKATCHEWAN

[GRAPHIC OMITTED]

In the Southern Plains area, the Company holds interests ranging up to 100 per cent and averaging 83 per cent in 2,037,923 gross (1,699,254 net) acres of producing and undeveloped land in the region, principally located south of the Northern Plains area to the United States border and to the east bounded by the Alberta-Saskatchewan border.

Reserves of natural gas, condensate and light and medium 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. With a higher sales price for natural gas, it is economic to drill shallow wells in closer proximity to each other, which may have smaller overall reserves and lower productivity per well, but will achieve a higher than average return on capital employed with low drilling costs and longer life reserves.

The Company maintains a large inventory of drillable locations on its land base in this region. This region is in the most mature portion 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 10.7 thousand bbl/d of crude oil and NGLs compared to 12.7 thousand bbl/d in 2005. Natural gas production amounted to 155.4 mmcf/d in 2005 compared to the 155.5 mmcf/d averaged in 2004.

During 2005, the Company drilled a total of 9.0 (2004 - 7.8) net crude oil wells, 336.5 (2004 - 220.6) net natural gas wells, 1.7 (2004 - 1.0) net stratigraphic/service well and 7.0 (2004 - 11.0) net dry wells in this region for a total of 354.2 (2004 - 240.4) net wells. The Company's average working interest in these wells was 81.0 per cent.

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 per cent and averaging 80 per cent in 246,304 gross (196,200 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 8.8 thousand bbl/d of crude oil and NGLs in 2005 compared to 9.3 thousand bbl/d in 2004. Natural gas production was steady averaging 3.1 mmcf/d in both 2005 and 2004.

The Company drilled 43.0 (2004 - 12.5) net crude oil wells, 1.0 (2004 - 0.0) net gas well, 7.6 (2004 - 0.0) net stratigraphic/service wells and 0.0 (2004 - 0.0) net dry wells in this region in 2005, for a total of 51.6 (2004 - 12.5) net wells. The Company's average working interest in these wells is 83.2 per cent.

HORIZON OIL SANDS PROJECT

[GRAPHIC OMITTED]

Canadian Natural owns a 100 per cent working interest in its Athabasca Oil Sands leases in Northern Alberta, of which a portion (being lease 18) is subject to a 5 per cent net carried interest in the bitumen development. The Horizon Oil Sands Project ("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 -36o API synthetic light crude oil ("SCO"), and associated infrastructure.

The project, which has two aspects; namely, 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 will continue through 2011 or 2012. Phase 1 production is targeted to begin in the second half of 2008 at 110 thousand bbl/d of SCO. Current plans have Phase 2 increasing production to 155 thousand bbl/d of SCO in 2010 and Phase 3 further increasing production to 232 thousand bbl/d of SCO in 2012. These targeted rates of production represent nominal design capacity. The Company is currently evaluating the opportunity to combine Phase 2 and Phase 3 for a joint operational date of 2011. Canadian Natural will seek to maximize resource recovery and overall production through ongoing optimization of operations. The phased approach provides the Company with improved cost and project controls in terms of labour and materials management and may mitigate any negative effects of growth on local infrastructure.

Using a cost environment associated with a US $45 WTI price per barrel of crude oil, total estimated capital construction costs of the phased development are $10.8 billion, of which approximately $6.8 billion, including

contingency funding of $700 million, would be required for Phase 1. When the Horizon Project is fully commissioned, operating costs - including sustaining capital - are expected to be in the range of $15 per barrel (based upon a natural gas price input of US$ 5.83/mcf).

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.

Throughout the first half of 2003, Canadian Natural, along with other major energy project proponents and the Canadian Association of Petroleum Producers, actively sought greater clarity from the federal government about the long-term climate change policy framework. Of particular concern was the period beyond 2012 when policies will be developed in the context of Canada's negotiations for a second Kyoto implementation phase. In mid 2003 the Government of Canada acknowledged the need for greater clarity and established eight principles that will guide the Government of Canada's longer-term climate change policies. These eight guiding principles addressed the key concerns of Canadian Natural with regard to equability, efficiency, flexibility and competitiveness issues for the post-2012 period.

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 third phase of FEL for Phase 2 is expected to be completed in the first quarter of 2007.

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 operating costs. By the end of 2004 the Company had acquired all key technologies for the project. At year end 2005, Canadian Natural's Horizon Project team, consisted of 521 permanent employees. This represents a total of 67 per cent of the 773 staff positions required by year end 2006. Of the 252 outstanding positions, 110 are filled by contractors on an interim basis for total of 82 per cent of our 2006 year end position requirements.

Horizon Project costs were approximately $1.5 billion in 2005 and cumulative expenditures were approximately $2.2 billion through the end of 2005. These expenditures include capitalized interest, stock based compensation, lease

evaluation, engineering definition, technology acquisition, completion of road infrastructure to the site, initial camp construction, detailed engineering, significant site development and initial foundation construction. Construction costs for 2006 are budgeted to be approximately $2.6 billion reflecting major expenditures for detailed engineering, procurement and construction of Phase 1 of the Project. In addition, capital expenditures of $128 million are budgeted for Phase 2 EDS development in 2006.

During 2005, the Company drilled 126 (2004 - 218) stratigraphic test wells to further delineate the ore body and confirm resource quality and quantity.

UNITED KINGDOM NORTH SEA

[GRAPHIC OMITTED] [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 per cent up to 100 per cent in 595,051 gross (444,314 net) acres of producing and non-producing properties in the UK sector of the North Sea. In 2005, the Company produced from 16 crude oil fields.

The northerly fields are centered around the Ninian Field where the Company has an 87.1 per cent 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 per cent to 100 per cent. 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 licenses 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 the central portion of the North Sea, in 2003, the Company increased its equity in the Banff Field to 87.6 per cent and took over as operator. The Company also owns a 45.7 per cent 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 is expected to result in lower combined operating costs from these fields.

In 2004, the Company acquired 100 per cent working interest in T-block (comprising the Tiffany, Toni and Thelma Fields) and 68.7 per cent to 75.3 per cent interests in the Fields known as B-block (comprising Balmoral, Stirling and Glamis). The Company took over as operator of these fields.

Ownership and operatorship levels in the North Sea are now similar to those levels found throughout the Company's other worldwide operations. The Company also 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 2005, production to the Company from this region averaged 68.6 thousand bbl/d of crude oil, up from 64.7 thousand bbl/d in 2004. Natural gas production averaged 18.4 mmcf/d in 2005, down from 50.4 mmcf/d in 2004 primarily due to the re-injection of associated natural gas production into the Banff Field for improved crude oil recovery.

The Company drilled 11.5 (2004 - 9.2) net crude oil wells, 0.9 (2004 - 2.7) net stratigraphic/service wells and 1.7 (2004 - 2.0) net dry wells in 2004 in this region for a total of 14.1 (2004 - 13.9) net wells. The Company's average working interest in these wells is 88.0 per cent.

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. The Company owns working interests ranging from 50 per cent to 100 per cent in 1,596,013 gross (887,657 net) acres in those countries. Since 2000, the Company has either relinquished or sold all of its interests in offshore Angola.

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 per cent interest in a production sharing agreement for the block.

The Company also has a 100 per cent 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 three exploration licences offshore Cote d'Ivoire comprising 275,625 net acres. During 2001, the Company increased its interest in Block CI-26, which contains the Espoir Field, to a 58.7 per cent 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 includes 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. An infill drilling program in East Espoir was commenced in 2005 and following its completion development drilling will commence at West Espoir.

Crude oil from the East Espoir Field is produced into an FPSO with 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 and 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 per cent interest. The well encountered hydrocarbons at a rate of 6.7 thousand barrels of crude oil per day. A second test well in 2002 also produced hydrocarbons at a rate in excess of 10 thousand barrels of crude oil per day. 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 thousand bbl/d net to Canadian Natural from 4 wells. Upon completion of drilling additional wells in 2006, production levels are expected to increase another 5 thousand bbl/d net to the Company. In East Espoir, two of four infill wells were completed in 2005 increasing production by 3 thousand bbl/d in the second quarter of 2005. The remaining two infill wells are expected to be completed in 2006. Construction of the West Espoir drilling tower was completed and installed to facilitate development drilling of the reservoir and it is expected that production will commence in 2006.

To date political unrest 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 2005, Company production averaged 22.9 thousand bbl/d of crude oil compared to 11.6 thousand bbl/d in 2004. Company natural gas production amounted to 4.2 mmcf/d in 2005 compared to 7.5 mmcf/d in 2004.

In 2005, the Company drilled 3.5 (2004 - 2.3) net crude oil wells, 1.1 (2004 - 0.0) net stratigraphic/service wells and 0.6 (2004 - 0.7) net dry wells for a total of 5.2 (2004 - 3.0) net wells. The Company's average working interest in these wells is 58.2 per cent.

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ANGOLA

During 2002, the Company was awarded operatorship and a 50 per cent working interest in exploration Block 16 situated offshore The People's Republic of Angola. 3-D seismic data was obtained over the entire Block 16 before obtaining title and identified two targets: Omba in the north and Zenza in the west central portion of the Block. The Company has a two well commitment over a four year time frame expiring August 31, 2006. The first well, Zenza-1, was drilled during the fourth quarter of 2003 and was not considered commercial. Following further evaluation of seismic data and the well results during 2004 and even though additional review of seismic and geological data on Block 16 indicates that significant upside remains a possibility, the risk level associated with Block 16 is outside the normal operating parameters of the Company. As a result, the Company entered into an agreement to dispose of its interest in Block 16 effective December 31, 2005. As of the sale of Block 16, the Company no longer has any holdings in Angola.

GABON

[GRAPHIC OMITTED]

The Company acquired permit (No. G4-187) comprising a 90 per cent operating interest in the production sharing agreement for the block containing the Olowi Field, 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 and is estimated to potentially contain up to 500 million barrels of 34(0) API light crude original oil in place. The crude oil reservoir is overlain by a large gas cap with potentially up to 1 trillion cubic feet of original gas in place. 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 of the crude oil reserves will commence in late 2006 with first production targeted for late 2008 at a rate of 20 thousand bbl/d.

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

For the year ended December 31, 2005, Canadian Natural retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule") and Ryder Scott Company ("Ryder Scott"), to evaluate 100% of the Company's conventional proved and probable crude oil, NGL and natural gas reserves and prepare Evaluation Reports on these reserves. Sproule evaluated the Company's North America conventional assets and Ryder Scott evaluated its international conventional assets. The Company has been granted an exemption from the 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 United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. There are two principal differences between the two standards. The first is the additional requirement under NI 51-101 to disclose both proved, 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 Company has disclosed proved conventional reserves and the Standardized Measure of discounted future net cash flows using constant prices and costs as mandated by the SEC in the supplemental oil and gas information section of its annual report. The Company has also elected to provide the net present value of these same conventional proved reserves as well as the conventional proved and probable reserves and the net present value of these reserves under the same parameters as additional voluntary information. In addition to the constant price and cost scenario, the Company has also elected to provide both conventional proved and conventional proved and probable reserves, as well as the net present value of these reserves, using forecast prices and costs as voluntary additional information.

Reserves and net present values of these reserves presented for years prior to 2003 were evaluated in accordance with the standards of National Policy 2-B which has now been replaced by NI 51-101. The stated reserves were reasonably evaluated as economically productive using year-end costs and prices escalated at appropriate rates throughout the productive life of the properties.

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, NGL and natural gas reserves.

The following tables summarize the evaluations of conventional reserves and estimated net present values of these reserves at December 31, 2005.

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 WITH THE EXCEPTION OF OFFSHORE WEST AFRICA WHERE ALL EXISTING AND FUTURE ABANDONMENT LIABILITIES HAVE BEEN INCLUDED. NO INDIRECT COSTS SUCH AS OVERHEAD, INTEREST AND ADMINISTRATIVE EXPENSES HAVE BEEN DEDUCTED FROM THE

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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, NGL AND NATURAL GAS RESERVES (NET OF ROYALTIES)

	Constant Prices and Costs		
	Crude Oil & NGLs (mmbbl)		Natural Ga
	Total Proved Reserves	Total Proved and Probable Reserves	Total Proved Reserves
NORTH AMERICA			
Canada	694	1,035	2,739
United States	-	-	2
INTERNATIONAL			
United Kingdom	290	417	29
Cote d'Ivoire	119	189	72
Gabon	15	17	-
TOTAL	1,118	1,658	2,842

CONVENTIONAL CRUDE OIL, NGL AND NATURAL GAS RESERVES

	Constant Prices and Costs		
	Crude Oil & NGLs (mmbbl)		Natural G
	Company Gross	Net	Company Gross
Proved developed reserves	762	696	2,871
Proved undeveloped reserves	461	422	619
TOTAL PROVED RESERVES	1,223	1,118	3,490
TOTAL PROVED AND PROBABLE RESERVES	1,801	1,658	4,568

ESTIMATED NET PRESENT VALUES

($ millions)	Constant Prices and Costs		
	Undiscounted	Discounted at	
		10%	15%
Proved developed reserves	37,183	24,275	20,939
Proved undeveloped reserves	12,035	6,342	4,881
TOTAL PROVED RESERVES	49,218	30,617	25,820
TOTAL PROVED AND PROBABLE RESERVES	68,543	38,682	31,642

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CONVENTIONAL CRUDE OIL, NGL AND NATURAL GAS RESERVES

	Forecast Prices and Costs		
	Crude Oil & NGLs (mmbbl)		Natural Gas
	Company Gross	Net	Company Gross
Proved developed reserves	752	685	2,814
Proved undeveloped reserves	462	421	617
TOTAL PROVED RESERVES	1,214	1,106	3,431

TOTAL PROVED AND PROBABLE RESERVES	1,792	1,642	4,485

ESTIMATED NET PRESENT VALUES

($ millions)	Forecast Prices and Costs		
	Undiscounted	Discounted at	
		10%	15%
Proved developed reserves	31,154	22,175	19,662
Proved undeveloped reserves	10,543	5,501	4,232
TOTAL PROVED RESERVES	41,697	27,676	23,894
TOTAL PROVED AND PROBABLE RESERVES	57,892	34,446	28,800

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 and their associated net present values using forecast prices and costs as well as before royalties 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 and their associated net present values using forecast prices and costs as well as before royalties 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 and their associated net present values using forecast prices and costs as well as before royalties 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 per cent probability that the quantities actually recovered will equal or exceed the stated values. The Company has elected to disclose proved plus probable reserves and their associated net present values using both constant prices and costs as well as forecast prices and costs and has disclosed these before and net of royalties. The calculation of a probable reserves and value component by subtracting the proved reserves from the proved plus probable reserves may be subject to error due to the different standards applied in the determination of each value. The impact, however, is not material.

7. Canadian securities legislation and policies permit the disclosure, which is included or incorporated by reference herein under a multi-jurisdictional disclosure system adopted by the SEC, of probable reserves which may not be disclosed in registration statements otherwise filed with the SEC. 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 2005 adjusted for quality and transportation as well as the 2005 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 2006 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:

	NATURAL GAS				CRUDE OIL		
YEAR	Company Average Price C$/MCF	Henry Hub Louisiana US$/MMBTU	AECO C$/MMBTU	Huntingdon/ Sumas C$/MMBTU	Company Average Price C$/BBL	WTI@ Cushing(i) US$/BBL	Ha He (degr
2006	9.45	10.08	9.99	9.53	46.12	61.04	

(i) "WTI @ Cushing" refers to the price of West Texas Intermediate crude oil at Cushing, Oklahoma.

(ii) "Edmonton Par" refers to the price of light gravity (40o API), low sulphur content crude oil at Edmonton, Alberta.

(iii) Foreign exchange rate used was US$0.8598/C$1.00

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 1.5 per cent per year. Future crude oil, NGLs and natural gas price forecasts were based on Sproule's December 31, 2005 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 2005 were $46.86 per barrel and $8.57 per mcf respectively, before adjustments due to hedging. The crude oil and natural gas forecast prices used in the Evaluation Reports are as follows:

	NATURAL GAS				CRUDE OIL		
YEAR	Company Average Price C$/MCF	Henry Hub Louisiana US$/MMBTU	AECO C$/MMBTU	Huntingdon/ Sumas C$/MMBTU	Company Average Price C$/BBL	WTI@ Cushing(i) US$/BBL	Ha He (degr
2006	11.07	11.59	11.58	11.34	48.30	60.81	
2007	10.33	10.11	10.84	10.70	49.59	61.61	
2008	8.43	8.50	8.95	8.81	45.31	54.60	
2009	7.35	7.58	7.87	7.73	42.12	50.19	
2010	7.05	7.32	7.57	7.43	39.53	47.76	
2011	7.21	7.43	7.70	7.56	40.57	48.48	
2012	7.34	7.54	7.83	7.69	40.14	49.20	
2013	7.48	7.66	7.96	7.82	41.22	49.94	
2014	7.61	7.77	8.09	7.95	41.34	50.69	
2015	7.75	7.89	8.23	8.09	42.02	51.45	
2016	7.86	8.01	8.37	8.23	42.03	52.22	

(i) Foreign exchange rate used was US$0.8598/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 with the exception of Offshore West Africa where existing asset liabilities were included.

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

	PROVED		PROVED AND PROBABLE	
	FORECAST PRICE CASE ($ millions)	CONSTANT PRICE CASE ($ millions)	FORECAST PRICE CASE ($ millions)	CONSTANT P ($ mill
2006	1,433	1,412	1,614	1,
2007	815	774	1,140	1,
2008	1,017	930	1,774	1,
2009	428	373	1,144	1,
2010	315	286	794	
2011	173	154	306	
2012	223	191	362	
2013	180	102	200	
2014	87	115	222	
2015	143	120	247	
2016	182	141	220	
2017	174	136	238	
Thereafter	555	398	773	

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 Schedules 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:

	Crude Oil & NGLs (mmbbl)			N
			Offshore	
	North	North	West	North

	America	Sea	Africa	Total	America
PROVED RESERVES					
RESERVES, DECEMBER 31, 2003	588	222	85	895	2,426
Extensions & Discoveries	17	-	-	17	334
Infill Drilling	24	35	-	59	74
Improved Recovery	1	10	-	11	6
Property purchases	36	38	-	74	182
Property disposals	-	-	-	-	(8)
Production	(66)	(24)	(4)	(94)	(383)
Revisions of prior estimates	48	22	34	104	(40)
RESERVES, DECEMBER 31, 2004	648	303	115	1,066	2,591
Extensions & Discoveries	98	-	-	98	506
Infill Drilling	3	3	2	8	22
Improved Recovery	-	-	-	-	8
Property purchases	-	-	15	15	6
Property disposals	(3)	-	-	(3)	(23)
Production	(70)	(25)	(8)	(103)	(411)
Revisions of prior estimates	18	9	10	37	42
RESERVES, DECEMBER 31, 2005	694	290	134	1,118	2,741
PROVED AND PROBABLE RESERVES					
RESERVES, DECEMBER 31, 2003	857	317	133	1,307	2,919
Extensions & Discoveries	20	-	-	20	418
Infill Drilling	29	49	-	78	106
Improved Recovery	2	10	-	12	6
Property purchases	49	49	-	98	236
Property disposals	-	-	-	-	(10)
Production	(66)	(24)	(4)	(94)	(383)
Revisions of prior estimates	35	14	67	116	27
RESERVES, DECEMBER 31, 2004	926	415	196	1,537	3,319
Extensions & Discoveries	200	-	-	200	645
Infill Drilling	3	5	6	14	23
Improved Recovery	-	-	-	-	14
Property purchases	-	-	17	17	8
Property disposals	(4)	-	-	(4)	(30)
Production	(70)	(25)	(8)	(103)	(411)
Revisions of prior estimates	(20)	22	(5)	(3)	(20)
RESERVES, DECEMBER 31, 2005	1,035	417	206	1,658	3,548

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 2005 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 per cent working interest in its Athabasca Oil Sands leases in Northern Alberta, of which a portion (being lease 18), is subject to a 5 per cent 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. Canadian Natural's development plan for the Horizon Project is to produce 232,000 barrels of synthetic crude oil per day. The project production schedule has been developed such that production rates are increased over three phases. Synthetic crude oil production is planned for the second half of 2008 at 110 thousand bbl/d, increasing to 232 thousand bbl/d by the third quarter of 2011. 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. Preparation for construction of Phase 1 of the Horizon Project began in late 2004. Total targeted capital costs for all three phases of the development are projected to be approximately $10.8 billion at a cost environment associated with a US $45 WTI price per barrel of crude oil.

An independent qualified reserves evaluator, GLJ Petroleum Consultants ("GLJ"), was retained to evaluate 100 per cent of the first three phases of the Horizon Project's development plan. GLJ's Evaluation Report indicates that the gross proved and probable reserves associated with the Horizon Project are 2.9 billion barrels of synthetic crude oil with a production life of 37 years.

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

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FIGURE 1 - LOCATION OF THE HORIZON OIL SANDS PROJECT

[GRAPHIC OMITTED] [GRAPHIC OMITTED]

TABLE 1 - CANADIAN NATURAL ATHABASCA REGION OIL SAND LEASES

SHORT LEASE NAME	OFFICIAL LEASE NUMBER	LEASE EXPIRY DATE(1)	AREA IN H

Lease 18	727912T18	Continued Producing(2)	1
Lease 10	7400120010	December 14, 2015	
Lease 25	7401050025	May 17, 2016	
Lease 11	7400120011	December 14, 2015	
Lease 12	7400120012	December 14, 2015	
Lease 13	7400120013	December 14, 2015	
Lease 15	7400120015	December 14, 2015	
Lease 19	7402050019	May 30, 2017	
Lease 20	7402050020	May 30, 2017	
Lease 6	7597050T06	May 6, 2012	
Lease 7	7597050T07	May 6, 2012	

(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.

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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 Energy and Utilities Board, 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 2005, key development achievements associated with the Horizon Project were as follows:

- Phase 1 Construction is 19% complete.
- Mine overburden is at 6.7 million bank cubic meters of material removed.
- Coker and Extraction Separation Cell foundations are complete.
- Critical path underground piping is complete.

The Coker Drums and Naphtha Reactor arrived on site in January 2006

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 Oil Sands 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 5 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

[GRAPHIC OMITTED]

HORIZON OIL SANDS PROJECT MINING RESERVES

For the year ended December 31, 2005, the Company retained GLJ to evaluate 100 per cent of phases 1, 2 and 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, NGL and natural gas reserves.

The pit limits and mine plans were updated in 2005 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 2.9 million barrels of gross proved and probable synthetic crude oil reserves shown in the table are produced from 37 years of projected production from the first three phases of the project 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.

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

[GRAPHIC OMITTED]

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FIGURE 4 - HORIZON OIL SANDS PROJECT CORE HOLE COVERAGE

[GRAPHIC OMITTED]

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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, 2005:

	Constant Prices		
	Bitumen (mmbbl)		Synthe
	Gross (2)	Net	Gro

Total proved reserves	2,235	1,848
Total proved and probable reserves	3,430	2,848

(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 reserves mean the total remaining recoverable reserves before consideration of company interests or royalties.

E. CRUDE OIL, NGLS AND NATURAL GAS PRODUCTION

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

	YEAR ENDED DECEMBER 31	
	2005	2004
Daily Production, before royalties		
Crude Oil and NGLs (bbl/d)	313,168	282,489
Natural Gas (mmcf/d)	1,439	1,388
Annual Production, before royalties		
Crude Oil and NGLs (mbbl)	114,306	103,391
Natural Gas (bcf)	525	508

NETBACKS
INFORMATION BY QUARTER

	YEAR 2005						
	1ST QUARTER	2ND QUARTER	3RD QUARTER	4TH QUARTER	YEAR ENDED	1ST QUARTER	2ND QUAR
Average Daily Production Volumes, before royalties							
Crude oil and NGLs (bbl/d)	287,803	289,064	334,724	340,268	313,168	261,286	275,
Natural Gas (mcf/d)	1,455	1,454	1,423	1,423	1,439	1,294	1,
PRODUCT NETBACKS							
Crude oil and NGLs ($/bbl)							

Sales Price (1)	$ 39.81	$ 42.51	$ 57.35	$ 46.38	$ 46.86	$ 34.21	$ 36
Royalties	$ 3.39	$ 3.33	$ 5.11	$ 3.89	$ 3.97	$ 2.91	$ 3
Production Expenses	$ 11.30	$ 11.66	$ 11.48	$ 10.33	$ 11.17	$ 9.58	$ 9
NETBACK	$ 25.12	$ 27.52	$ 40.76	$ 32.16	$ 31.72	$ 21.72	$ 23
Natural Gas ($mcf)							
Sales Price (1)	$ 6.68	$ 7.33	$ 8.61	$ 11.67	$ 8.57	$ 6.31	$ 6
Royalties	$ 1.30	$ 1.48	$ 1.93	$ 2.30	$ 1.75	$ 1.27	$ 1
Production Expenses	$ 0.69	$ 0.71	$ 0.76	$ 0.76	$ 0.73	$ 0.65	$ 0
NETBACK	$ 4.69	$ 5.14	$ 5.92	$ 8.61	$ 6.09	$ 4.39	$ 4
CRUDE OIL AND NGL NETBACKS BY TYPE							
Light/Pelican Lake/NGLs ($/bbl)							
Sales Price (1)	$ 53.14	$ 56.85	$ 66.81	$ 58.87	$ 59.16	$ 40.75	$ 45
Royalties	$ 5.20	$ 4.55	$ 5.50	$ 4.40	$ 4.90	$ 3.71	$ 3
Production Expenses	$ 11.58	$ 12.28	$ 11.47	$ 8.90	$ 10.93	$ 9.77	$ 10
NETBACK	$ 36.36	$ 40.02	$ 49.84	$ 45.57	$ 43.33	$ 27.27	$ 30
Heavy Crude Oil ($/bbl)							
Sales Price (1)	$ 25.21	$ 27.82	$ 47.25	$ 30.27	$ 33.09	$ 27.00	$ 28
Royalties	$ 1.41	$ 2.07	$ 4.83	$ 3.08	$ 2.92	$ 2.02	$ 2
Production Expenses	$ 11.00	$ 11.03	$ 11.50	$ 12.18	$ 11.44	$ 9.38	$ 9
Netback	$ 12.80	$ 14.72	$ 30.92	$ 15.01	$ 18.73	$ 15.60	$ 16

NOTE: Pelican Lake crude oil has an API of 12(0) to 17(0), but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.

(1) INCLUDING TRANSPORTATION AND EXCLUDING RISK MANAGEMENT ACTIVITIES

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NETBACKS
INFORMATION BY QUARTER

	YEAR 2005						
	1ST QUARTER	2ND QUARTER	3RD QUARTER	4TH QUARTER	YEAR ENDED	1ST QUARTER	2ND QUART
SEGMENTED							
NORTH AMERICA PRODUCT NETBACKS							
Light/Pelican Lake/NGLs ($/bbl)							
Sales Price (1)	$ 45.80	$ 49.78	$ 61.21	$ 52.10	$ 52.35	$ 37.54	$ 41.
Royalties	$ 10.64	$ 8.77	$ 11.49	$ 9.62	$ 10.13	$ 7.20	$ 7.
Production Expenses	8.30	$ 8.40	$ 9.27	$ 8.60	$ 8.65	$ 7.30	$ 7.
NETBACK	$ 26.86	$ 32.61	$ 40.45	$ 33.88	$ 33.57	$ 23.04	$ 25.
Heavy Crude Oil ($/bbl)							
Sales Price (1)	$ 25.21	$ 27.82	$ 47.25	$ 30.27	$ 33.09	$ 27.00	$ 28.
Royalties	$ 1.41	$ 2.07	$ 4.83	$ 3.08	$ 2.92	$ 2.02	$ 2.
Production Expenses	$ 11.00	$ 11.03	$ 11.50	$ 12.18	$ 11.44	$ 9.38	$ 9.
NETBACK	$ 12.80	$ 14.72	$ 30.92	$ 15.01	$ 18.73	$ 15.60	$ 16.

Natural Gas ($/mcf)							
Sales Price (1)	$ 6.73	$ 7.38	$ 8.69	$ 11.79	$ 8.65	$ 6.37	$ 6.
Royalties	$ 1.33	$ 1.50	$ 1.96	$ 2.34	$ 1.78	$ 1.33	$ 1.
Production Expenses	$ 0.66	$ 0.68	$ 0.74	$ 0.74	$ 0.71	$ 0.60	$ 0.
NETBACK	$ 4.74	$ 5.20	$ 5.99	$ 8.71	$ 6.16	$ 4.44	$ 4.
NORTH SEA PRODUCT NETBACKS							
Light Oil ($/bbl)							
Sales Price (1)	$ 59.56	$ 64.81	$ 74.46	$ 66.88	$ 66.57	$ 44.27	$ 49.
Royalties	$ 0.05	$ 0.11	$ 0.12	$ 0.14	$ 0.10	$ 0.06	$ 0.
Production Expenses	$ 14.91	$ 17.41	$ 15.15	$ 12.11	$ 14.94	$ 13.26	$ 13.
NETBACK	$ 44.60	$ 47.29	$ 59.19	$ 54.63	$ 51.53	$ 30.95	$ 35.
Natural Gas ($/mcf)							
Sales Price (1)	$ 3.52	$ 3.07	$ 2.64	$ 3.40	$ 3.17	$ 5.08	$ 3.
Royalties	$ --	$ --	$ --	$ --	$ --	$ --	$
Production Expenses	$ 2.52	$ 2.92	$ 2.30	$ 1.96	$ 2.44	$ 1.65	$ 1.
NETBACK	$ 1.00	$ 0.15	$ 0.34	$ 1.44	$ 0.73	$ 3.43	$ 1.
OFFSHORE WEST AFRICA PRODUCT NETBACKS							
Light Oil ($/bbl)							
Sales Price (1)	$ 62.34	$ 58.24	$ 59.09	$ 60.19	$ 59.91	$ 42.08	$ 49.
Royalties	$ 1.90	$ 1.81	$ 1.54	$ 1.57	$ 1.62	$ 1.28	$ 1.
Production Expenses	$ 11.43	$ 8.47	$ 5.81	$ 5.62	$ 6.50	$ 7.09	$ 7.
NETBACK	$ 49.01	$ 47.96	$ 51.74	$ 53.00	$ 51.79	$ 33.71	$ 40.
Natural Gas ($/mcf)							
Sales Price (1)	$ 7.67	$ 6.88	$ 5.52	$ 5.13	$ 5.91	$ 4.80	$ 5.
Royalties	$ 0.23	$ 0.21	$ 0.13	$ 0.14	$ 0.16	$ 0.15	$ 0.
Production Expenses	$ 1.25	$ 1.37	$ 1.09	$ 0.80	$ 1.05	$ 1.23	$ 1.
NETBACK	$ 6.19	$ 5.30	$ 4.30	$ 4.19	$ 4.70	$ 3.42	$ 3.

NOTE: Pelican Lake crude oil has an API of 12(0) to 17(0), but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.

(1) INCLUDING TRANSPORTATION AND EXCLUDING RISK MANAGEMENT ACTIVITIES.

NETBACKS
INFORMATION BY QUARTER

	YEAR 2003			
	1ST QUARTER	2ND QUARTER	3RD QUARTER	4TH QUARTE
Average Daily Production Volumes				
Crude oil and NGLs (bbl/d)	237,560	240,607	247,016	244,2
Natural Gas (mcf/d)	1,310	1,325	1,289	1,2
PRODUCT NETBACKS				

Crude oil and NGLs ($/bbl)				
Sales Price (1)	$ 39.37	$ 30.66	$ 31.45	$ 29.
Royalties	$ 3.56	$ 2.78	$ 2.56	$ 2.
Production Expenses	$ 10.79	$ 10.80	$ 10.14	$ 9.
NETBACK	$ 25.02	$ 17.08	$ 18.75	$ 17.
Natural Gas ($/mcf)				
Sales Price (1)	$ 7.75	$ 6.25	$ 5.57	$ 5.
Royalties	$ 1.78	$ 1.35	$ 1.11	$ 1.
Production Expenses	$ 0.57	$ 0.59	$ 0.63	$ 0.
NETBACK	$ 5.40	$ 4.31	$ 3.83	$ 3.
CRUDE OIL AND NGLS NETBACKS BY TYPE				
Light/Pelican Lake/NGLs ($/bbl)				
Sales Price (1)	$ 44.38	$ 34.60	$ 36.06	$ 35.
Royalties	$ 4.18	$ 3.32	$ 3.11	$ 2.
Production Expenses	$ 10.42	$ 9.76	$ 9.53	$ 9.
NETBACK	$ 29.78	$ 21.52	$ 23.42	$ 23.
Heavy Crude Oil ($/bbl)				
Sales Price (1)	$ 32.44	$ 25.37	$ 25.17	$ 21.
Royalties	$ 2.71	$ 2.06	$ 1.83	$ 1.
Production Expenses	$ 11.30	$ 12.19	$ 10.96	$ 9.
Netback	$ 18.43	$ 11.12	$ 12.38	$ 10.

NOTE: Pelican Lake crude oil has an API of 12(0) to 17(0), but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.

(1) INCLUDING TRANSPORTATION AND EXCLUDING RISK MANAGEMENT ACTIVITIES.

NETBACKS
INFORMATION BY QUARTER

	YEAR 2003			
	1ST QUARTER	2ND QUARTER	3RD QUARTER	4
SEGMENTED				
NORTH AMERICA PRODUCT NETBACKS				
Light/Pelican Lake/NGLs ($/bbl)				
Sales Price (1)	$ 40.89	$ 32.73	$ 32.78	$
Royalties	$ 7.65	$ 6.33	$ 6.04	$
Production Expenses	$ 6.09	$ 6.42	$ 6.76	$
NETBACK	$ 27.15	$ 19.98	$ 19.98	$
Heavy Crude Oil ($/bbl)				
Sales Price (1)	$ 32.44	$ 25.37	$ 25.17	$
Royalties	$ 2.71	$ 2.06	$ 1.83	$
Production Expenses	$ 11.30	$ 12.19	$ 10.96	$
NETBACK	$ 18.43	$ 11.12	$ 12.38	$
Natural Gas ($/mcf)				

Sales Price (1)	$ 7.88	$ 6.39	$ 5.70	$
Royalties	$ 1.84	$ 1.40	$ 1.16	$
Production Expenses	$ 0.55	$ 0.56	$ 0.58	$
NETBACK	$ 5.49	$ 4.43	$ 3.96	$
NORTH SEA PRODUCT NETBACKS				
Light Crude oil ($/bbl)				
Sales Price (1)	$ 49.74	$ 37.08	$ 39.63	$
Royalties	$ 0.11	$ (0.19)	$ 0.09	$
Production Expenses	$ 15.50	$ 14.17	$ 13.25	$
NETBACK	$ 34.13	$ 23.10	$ 26.29	$
Natural Gas ($/mcf)				
Sales Price (1)	$ 4.03	$ 2.21	$ 2.57	$
Royalties	$ --	$ --	$ --	$
Production Expenses	$ 1.09	$ 1.45	$ 1.60	$
NETBACK	$ 2.94	$ 0.76	$ 0.97	$
OFFSHORE WEST AFRICA PRODUCT NETBACKS				
Light Crude oil ($/bbl)				
Sales Price (1)	$ 37.86	$ 34.34	$ 37.37	$
Royalties	$ 1.20	$ 0.99	$ 1.13	$
Production Expenses	$ 14.03	$ 9.32	$ 7.11	$
NETBACK	$ 22.63	$ 24.03	$ 29.13	$
Natural Gas ($/mcf)				
Sales Price (1)	$ 3.80	$ 5.09	$ 4.58	$
Royalties	$ 0.11	$ 0.15	$ 0.14	$
Production Expenses	$ 2.37	$ 1.45	$ 1.24	$
NETBACK	$ 1.32	$ 3.49	$ 3.20	$

NOTE: Pelican Lake crude oil has an API of 12(0) to 17(0), but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.

Including transportation and excluding risk management activities

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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 DECEMBER 31			
	2005		2004	
	Gross	Net	Gross	
Natural Gas	1,071	890	801	
Crude Oil	685	627	378	
Service/Stratigraphic	251	248	339	
Dry Holes	136	117	106	
Total	2,143	1,882	1,624	1,

*Total Success Rate	93%	

*excluding service and stratigraphic test wells

G. 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:

	YEAR ENDED DECEMBER 31	
	2005	2004
Net property (dispositions) acquisitions((1))	(320)	1,835
Land acquisition and retention	254	120
Seismic evaluation	132	89
Well drilling, completion and equipping	2,000	1,394
Pipeline and production facilities	1,295	821
Reserve replacement expenditures	3,361	4,259
Horizon Project:		
Phase 1 construction costs	1,329	--
Capitalized interest and other	170	291
Total Horizon Project	1,499	291
Midstream operations	4	16
Abandonments((2))	46	32
Head office equipment	22	35
Total Net Capital Expenditures	4,932	4,633

(1) Includes Business Combinations.

(2) Abandonments represent expenditures to settle retirement obligations and have been reflected as capital expenditures in this table.

2005 THREE MONTHS ENDED

CAPITAL EXPENDITURES BY QUARTER	($ millions) MAR. 31	JUNE 30	SEPT. 30
Net property (dispositions) acquisitions((1))	2	(341)	0
Land acquisition and retention	36	52	69
Seismic evaluation	41	20	31
Well drilling, completion and equipping	634	306	431
Pipeline and production facilities	432	283	266
Reserve replacement expenditures	1,145	320	797
Horizon Project			
Phase 1 construction costs	132	259	432
Capitalized interest and other	83	16	20
Total Horizon Project	215	275	452
Midstream operations	4	--	(1)
Abandonments((2))	4	7	19
Head office equipment	4	7	5
Total Net Capital Expenditures	1,372	609	1,272

(1) Includes Business Combinations.

(2) Abandonments represent expenditures to settle retirement obligations and have been reflected as capital expenditures in this table.

CAPITAL EXPENDITURES((1)) BY QUARTER	2004 THREE MONTHS ENDED ($ millions) MAR. 31	JUNE 30	SEPT. 30
Net property acquisitions((1))	507	277	290
Land acquisition and retention	31	39	37
Seismic evaluation	32	11	25
Well drilling, completion and equipping			

	583	231	221
Pipeline and production facilities	280	166	190
Reserve replacement expenditures	1,433	724	763
Midstream operations	-	3	2
Horizon Project	46	103	84
Abandonments((2))	7	6	14
Head office equipment	7	8	12
Total Net Capital Expenditures	1,493	844	875

(1) Includes Business Combinations.

(2) Abandonments represent expenditures to settle retirement obligations and have been reflected as capital expenditures in this table.

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H. UNDEVELOPED ACREAGE

The following table summarizes the Company's working interest holdings in core region non-reserve acreage as at December 31, 2005:

	GROSS ACRES (thousands)	NET ACRES (thousands)
NORTH AMERICA		
Alberta	9,892	8,376
British Columbia	2,645	2,010
Saskatchewan	615	549
Manitoba	11	11
NORTH SEA		
United Kingdom	457	352
OFFSHORE WEST AFRICA		
Cote d'Ivoire	369	274
Gabon	152	152
Total	14,141	11,724

I. DEVELOPED ACREAGE

The following table summarizes the Company's working interest holdings in core region developed acreage as at December 31, 2005:

	GROSS ACRES (thousands)	NET ACRES (thousands)
NORTH AMERICA		
Alberta	5,727	4,545
British Columbia	1,111	870
Saskatchewan	341	279
Manitoba	5	5
NORTH SEA		
United Kingdom	138	93
OFFSHORE WEST AFRICA		
Cote d'Ivoire	7	4
Total	7,329	5,796

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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 DECEMBER 3	
	2005	2004
	($ millions, except per share i	
Revenues (1) (net of royalties)	8,741	6,53
Cash flow from operations	5,021	3,76
Per common share - basic (3)	9.36	7.0
- diluted (3)	9.33	6.9
Net earnings	1,050	1,40
Per common share - basic (3)	1.96	2.6
- diluted (3)	1.95	2.6

Total assets	21,852	18,37
Total long-term debt(2)	3,321	3,53

	2005 THREE MONTHS ENDED			
	MARCH 31	JUNE 30	SEPT. 30	DEC.
	($ millions, except per share information)			
Revenues (1) (net of royalties)	1,734	1,881	2,515	2,
Net earnings (loss)	(424)	219	151	1,
Per common share - basic (3)	(0.79)	0.41	0.28	2
- diluted (3)	(0.79)	0.41	0.28	2

	2004 THREE MONTHS ENDED			
	MARCH 31	JUNE 30	SEPT. 30	DEC.
	($ millions, except per share information)			
Revenues (1) (net of royalties)	1,420	1,603	1,799	1,
Net earnings	258	259	311	
Per common share - basic (3)	0.49	0.48	0.58	1
- diluted (3)	0.48	0.48	0.57	1

(1) Excluding transportation costs and risk management activities.
(2) Excluding current portion of long-term debt.
(3) Restated to reflect two-for-one-share split in May 2005.

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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. There are no preferred shares currently outstanding.

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's senior unsecured long-term debt securities are rated "Baa1" with a stable trend by Moody's Investor Services, Inc. ("Moody's"), "BBB+" by Standard & Poor's Corporation ("S&P") and "BBB high" with a stable trend by Dominion Bond Rating Service Limited ("DBRS"). S&P assigns a rating outlook to the Company and not to individual debt instruments. S&P has assigned a negative outlook to the Company.

Rated Debt Issuances

$125 CAD million 7.40% unsecured note due 2007
$400 CAD million 4.95% unsecured note due 2015
$93 US million 6.45% adjustable rate note due 2009
$400 US million 6.70% unsecured note due 2011
$350 US million 5.45% unsecured note due 2012
$350 US million 4.90% unsecured note due 2014
$400 US million 7.20% unsecured note due 2032
$350 US million 6.54% unsecured note due 2033
$350 US million 5.85% unsecured note due 2035

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 Baa1 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 notes. 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 "high" and "low" grades are not used for the AAA category. The rating trend is DBRS' opinion regarding the outlook for the rating.

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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.

2005 Monthly Historical Trading on Toronto Stock Exchange

Month	High	Low	Close	Volume Traded
January	$55.70	$48.55	$54.74	23,564,720
February	74.25	54.60	70.09	31,090,409
March	74.75	63.79	68.36	29,853,739
April	71.88	61.07	62.40	27,675,887
May 1 - 17	71.09	61.90	67.00	13,881,359
*May 18 - 31	37.60	33.36	36.25	18,362,198
June	46.98	36.68	44.40	53,797,555
July	51.45	45.52	51.00	52,706,687
August	59.96	50.61	58.47	57,286,467
September	60.00	51.25	52.50	50,127,673
October	53.34	43.55	48.29	66,484,410
November	58.24	48.25	52.87	55,369,037
December	62.00	53.31	57.63	31,725,589

* Shares began trading on a post two-for-one subdivision basis on May 18, 2005.

On January 22, 2003, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of TSX and the NYSE, beginning January 24, 2003 and ending January 23, 2004, to purchase for cancellation up to 6,692,799 common shares of the Company, being 5 per cent of the 133,855,988 common shares of the Company outstanding on January 17, 2003. Under this program, the Company purchased a total of 2,734,800 common shares for cancellation at an average purchase price of $52.51 for each common share purchased.

On January 22, 2004, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of TSX and the NYSE, commencing January 24, 2004 and ending January 23, 2005, to purchase for cancellation up to 6,690,385 (13,380,770 post May 21, 2004 two-for-one stock split) common shares of the Company, being 5 per cent of the 133,807,695 (267,615,390 post May 21, 2004 two-for-one stock split) common shares of the Company outstanding on January 13, 2004. Under this program, the Company purchased a total of 873,400 common shares for cancellation at an average purchase price of $37.98 for each common share purchased; $38.01 after costs.

At the Annual and Special Meeting of Shareholders held May 6, 2004, 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 21, 2004.

On January 20, 2005, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of Toronto Stock Exchange and the New York Stock Exchange, 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 per cent 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 TSE 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 per cent of the 537,050,902 common shares of the Company outstanding on January 17, 2006. As of the date of this Annual Information Form, no shares have been purchased.

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 2004 and 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.

2005	2004	2003

Cash dividends declared per common share	$0.24	$0.20	$0.15

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.

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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 52)	Executive Vice-President, Risk Ma Financial Officer of Financial Off Health Region from 2002 the Calgary Vice-President, Corporate Services a February 2000 to 2002; prior theret since 1980, most recently as a Corp from 1991 to 2000. Has served contin of the Company since November 2003.
N. Murray Edwards Calgary/Banff, Alberta Canada	Vice-Chairman and Director(3) (age 46)	President, Edco Financial Holding management and consulting compa continuously as a director of the Com 1988. Currently serving on the boa Ensign Energy Services Inc. and Corporation.
Honourable Gary A. Filmon Winnipeg, Manitoba Canada	Director (1)(2) (age 63)	Consultant, Exchange Group (busine based in Winnipeg, Manitoba). Prior Premier of Manitoba from 1988 to continuously as a director of the Co 2006. Currently serving on the boa Manitoba Telecom Services Inc., Pol Fund, Arctic Glacier Income Trust, Income Fund, and as a member of the Marsh Canada.
Ambassador Gordon D. Giffin Atlanta, Georgia USA	Director(1)(2) (age 56)	Senior Partner, McKenna Long & Ald since May 2001; prior thereto United Canada. Has served continuously as Company since May 2002. Currently ser directors of Bowater, Inc.; Canadia Canadian Imperial Bank of Commerc

		Corporation.
John G. Langille Calgary, Alberta Canada	Vice-Chairman and Director (age 60)	Officer of the Company. Has serv director of the Company since June 19
Keith A.J. MacPhail Calgary, Alberta Canada	Director(3)(5) (age 49)	Chairman, President and Chief Executi Petroleum Ltd. (independent oil and since November 1997 and Chairman, NuV July 2003. Has served continuously Company since October 1993. Currently of directors of Bonavista Energy Tru Ltd.
Allan P. Markin Calgary, Alberta Canada	Chairman and Director(5) (age 60)	Chairman of the Company. Has serv director of the Company since January
Norman F. McIntyre Calgary, Alberta Canada	Director(3)(4)(5) (age 60)	An independent businessman. Prio Vice-President, Petro-Canada from 1 recently President, Petro-Canada 200 continuously as a director of the Com Currently serving on the board of Energy Inc. and Petro Andina Resource

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NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
James S. Palmer, C.M., A. O. E., Q.C. Calgary, Alberta Canada	Director(3)(4)(5) (age 77)	Chairman, Burnet, Duckworth & Palmer served continuously as a director of 1997. Currently serving on the bo Magellan Aerospace Corporation; Tren Energy Corp.; and, on the board of Sugar Income Fund..
Dr. Eldon R. Smith, M.D. Calgary, Alberta Canada	Director(1)(4)(5) (age 66)	Emeritus Professor and Former Dean, University of Calgary. Has served director of the Company since May 199 on the board of directors of Vaso Sciences Corp. and Overlord Financial
David A. Tuer Calgary, Alberta Canada	Director(1)(2)(3) (age 56)	An independent businessman. Chairm Region since October 2001 and Presi Inc. since April 2005. Prior theret Executive Officer, PanCanadian Energy recently President and CEO of Ha (independent oil and natural gas co 2003 to March 2005. Has served conti of the Company since May 2002. Curr board of directors of Sequoia Oil and Capital Corporation; and, Norquay Cap
Steve W. Laut	President and Chief	Officer of the Company.

Calgary, Alberta Canada	Operating Officer (age 48)	
Real M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 55)	Officer of the Company.
Real J. H. Doucet Calgary, Alberta Canada	Senior Vice-President, Oil Sands (age 53)	Officer of the Company.
Allen M. Knight Calgary, Alberta Canada	Senior Vice-President, International & Corporate Development (age 56)	Officer of the Company.
Tim S. McKay Calgary, Alberta Canada	Senior Vice-President, Operations (age 44)	Officer of the Company.
Douglas A. Proll Calgary, Alberta Canada	Chief Financial Officer and Senior Vice-President, Finance (age 55)	Officer of the Company since April Vice President Finance and Treasurer Ltd. to August 2000 and most rec Finance and Business Development of H August 2000 to February 2001.
Lyle G. Stevens Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 51)	Officer of the Company.
Jeffrey W. Wilson Calgary, Alberta Canada	Senior Vice-President, Exploration (age 53)	Officer of the Company since Septembe Exploration Manager of the Company.

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NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Corey B. Bieber Calgary, Alberta Canada	Vice-President, Investor Relations (age 42)	Officer of the Company since April Director of Corporate Accounting of E 2001, Treasurer of the Company March most recently Director, Investor Rel from July 2002 to April 2005.
Mary-Jo Case Calgary, Alberta Canada	Vice-President, Land (age 47)	Officer of the Company since May Co-ordinator Land at PanCanadian Petr and most recently Manager Commercial PanCanadian Petroleum Limited 1999 to
Wayne M. Chorney Calgary, Alberta Canada	Vice-President, Development Operations (age 46)	Officer of the Company since April Production Manager, Thermal Operat October 1999 to August 2001, General of CNR International (U.K.) Limite owned subsidiary of the Company Sep

		2001 and most recently Director, Pro CNRI August 2001 to April 2004.
William R. Clapperton Calgary, Alberta Canada	Vice-President, Regulatory, Stakeholder and Environmental Affairs (age 43)	Officer of the Company since January Manager, Surface Land and Environment
Gordon M. Coveney Calgary, Alberta Canada	Vice-President, Exploration, Northeast District (age 52)	Officer of the Company since Septembe Exploration Manager for the Company.
Randall S. Davis Calgary, Alberta Canada	Vice-President, Financial Accounting and Controls (age 39)	Officer of the Company since July Manager, Financial Reporting of the and most recently Financial Controlle July 2002 to July 2004.
Larry C. Galea Calgary, Alberta Canada	Vice-President, Operations Planning (age 40)	Officer of the Company since April Exploitation Manager of the Compan Manager, Operations Planning Januar and most recently Exploitation Manag April 2005.
Jerome W. Harvey Calgary, Alberta Canada	Vice-President, Commercial Operations (age 52)	Officer of the Company since April Manager, Commercial Operations.
Peter Janson Calgary, Alberta Canada	Vice-President, Engineering Integration (age 48)	Officer of the Company since December Director, Production Planning and Con Director, Health and Safety and Envir to November 2002 at Suncor Oil San Director, Engineering Integration November 2002 to December 2004.
Terry J. Jocksch Calgary, Alberta Canada	Vice-President, Exploitation East (age 38)	Officer of the Company since April Exploitation Manager of the Company t
Christopher M. Kean Calgary, Alberta Canada	Vice-President, Utilities and Offsite, Horizon Oil Sands Project (age 42)	Officer of the Company since December Manager Facilities Engineering to Jan and Offsites Project Manager Janua Director, Utilities and Offsites J and most recently General Manager, U July 2003 to December 2004.

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NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Philip A. Keele Calgary, Alberta Canada	Vice-President, Mining, Horizon Oil Sands Project (age 46)	Officer of the Company since December from Mine Manager at Fording Coal 2001, Chief Mine Engineer of the Com September 2002 and most recent

		Engineering of the Company from Septe 2004.
Cameron S. Kramer Calgary, Alberta Canada	Vice-President, Field Operations (age 38)	Officer of the Company since Septembe Production Engineer of the Company t recently Manager, Field Operations April 2000 to September 2002.
Leon Miura Calgary, Alberta	Vice-President, Upgrading (age 51)	Officer of the Company since August held progressively senior positions a Venezuela including Cerro Negro Exec Oil Upgrading from 1997 to 2001 and m Injection Project Director, Sec Petroleos de Venezuela 2002 to 2003.
John S. J. Parr Calgary, Alberta Canada	Vice-President, Production, East (age 44)	Officer of the Company since April Production Engineer, NE Gas of the Manager, Production Engineering of 2002 to June 2002 and most recently Heavy Oil of the Company from July 20
David A. Payne Calgary, Alberta Canada	Vice-President, Exploitation, West (age 44)	Officer of the Company since October Exploitation Manager, Thermal Heavy o 2000, Director, Exploitation of CNR Limited a wholly-owned subsidiary of 2000 to August 2003 and most re Manager, Technical Projects of the 2003 to October 2004.
William R. Peterson Calgary, Alberta Canada	Vice-President, Production, West (age 39)	Officer of the Company since April Production Manager, West of the Compa
John C. Puckering Calgary, Alberta Canada	Vice President, Site Development (age 59)	Officer of the Company since April General Manager DCL Construction I President of 960925 Alberta Ltd. f April 2002, Manager, Site Developmen May 2002 to December 2002 and mo Manager Site Development of the Comp to April 2004.
Sheldon L. Schroeder Calgary, Alberta Canada	Vice-President, Project Control (age 38)	Officer of the Company since April engineer with 729248 Alberta Ltd. Control Manager of the Company September 2002 and most recently Dire of the Company from September 2002 to
Kendall W. Stagg Calgary, Alberta Canada	Vice-President, Exploration, West (age 44)	Officer of the Company since October Cardium Geophysicist of the Company Geophysicist of the Company from Ap and most recently Manager Explora Company from June 2002 to September 2
Lynn M. Zeidler Calgary, Alberta Canada	Vice-President, Bitumen Production (age 49)	Officer of the Company since August held progressively senior positio Limited including on secondment from as Manager-Tier 1 Implementation at Inc to September 2000 and most recen Manager, Athabasca Oil Sands Proj Limited October 2000 to May 2003 and President & Project Director, Muskeg Sands Energy Inc. May 2002 to Jul

		Manager Claims Athabasca Oil Sands Pr Limited May 2003 to July 2003.

NAME	POSITION PRESENTLY HELD	PRINCIPAL OCCUPATION DURING PAST 5 YEARS
Kimberly I. McKay Calgary, Alberta Canada	Treasurer (age 37)	Officer of the Company since December Financial Accountant of the Compa Advisor Capital Markets and Treasury Company from October 2001 to July 20 Treasury Manager of the Company from 2004.
Bruce E. McGrath Calgary, Alberta Canada	Corporate Secretary (age 56)	Officer of the Company.

(1) Member of the Nominating and Corporate Governance Committee
(2) Member of the Audit Committee
(3) Member of the Reserves Committee
(4) Member of the Compensation Committee
(5) Member of the Safety, Health and Environmental Committee

All directors stand for election at each Annual General Meeting of Canadian Natural shareholders. With the exception of Messrs. N. F. McIntyre and G. A. Filmon who were appointed to the Board effective July 29, 2005 and February 21, 2006 respectively, all of the current directors were elected to the Board at the last annual meeting of shareholders held on May 5, 2005. All of the current directors are standing for election at the Annual General Meeting of Shareholders scheduled for May 4, 2006.

As at December 31, 2005, the directors and officers of the Company, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, in the aggregate, approximately 4 per cent of the total outstanding common shares (approximately 5 per cent 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 will 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 MI 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.

The Audit Committee in 2005 approved specified audit and non-audit services to be performed by PricewaterhouseCoopers LLP ("PwC") the independent auditor of the Corporation. The following table lists the fees accrued to PwC for fiscal year 2005.

AUDITOR SERVICE FEES

AUDITOR SERVICE	2005	2004
Audit fees	$1,200,235	$1,100,548
Audit related fees	$ 266,923	$ 183,663
Tax related fees	$ 39,331	$ 39,330
All other fees	$ 7,290	$ 0
Total Accrued Fees	$1,513,779	$1,323,541

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

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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

PricewaterhouseCoopers LLP, Chartered Accountants, are the Company's auditors and such firm has prepared an opinion with respect to the Company's consolidated financial statements as at and for the year ended December 31, 2005. PricewaterhouseCoopers LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

Sproule Associates Limited, Ryder Scott Company and GLJ Petroleum Consultants have provided the Report on Reserves Data attached as Schedule "A" to this Annual Information Form in their capacity as the Company's Independent Qualified Reserves Evaluators. Sproule Associates Limited, Ryder Scott Company and GLJ Petroleum Consultants and their directors, officers and associates, collectively own less than 1% of the Company's outstanding common shares.

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 15, 2006 in connection with the Annual General Meeting of Shareholders of Canadian Natural to be held on May 4, 2006 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, 2005 found on pages 45 to 73, 74 to 96 and 97 to 101 respectively, of the 2005 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, 2005. 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, 2005 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, 2005 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, 2005.

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

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discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2005, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's management and board of directors:

INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR	DESCRIPTION AND PREPARATION DATE OF EVALUATION REPORT	LOCATION OF RESERVES (COUNTRY OR FOREIGN GEOGRAPHIC AREA)	NET PRESENT VALUES OF CONVENTIONA (BEFORE INCOME TAXES, 10% DISCO		
			AUDITED MM$	EVALUATED MM$	REVIEWED MM$
Sproule Associates Ltd.	Sproule Evaluated the P&NG Reserves as reported February 7,	Canada, USA	$0	$20,727	$0

	2006.				
Ryder Scott Company	Ryder Scott Evaluated the P&NG Reserves as reported February 7, 2006.	United Kingdom and Offshore West Africa	$0	$ 9,890	$0
TOTALS			$0	$30,617	$0

In addition, both proved, and proved and probable reserves have been evaluated for oil sands mining properties located in Canada. The Horizon Project reserves were evaluated as at December 31, 2005. 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 7, 2006

SPROULE ASSOCIATES LIMITED

ORIGINAL SIGNED BY:

/s/ Harry J. Helwerda

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

ORIGINAL SIGNED BY:

/s/ Doug Ho

Doug Ho, P.Eng.
Manager, Engineering, and Associate

ORIGINAL SIGNED BY:

/s/ Ken H. Crowther

Ken H. Crowther, P.Eng.
President, Canada and U.S.

RYDER SCOTT COMPANY

ORIGINAL SIGNED BY:

/s/ Jane Tink

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

GLJ PETROLEUM CONSULTANTS

ORIGINAL SIGNED BY:

/s/ James H. Willmon

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

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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, 2005 using constant prices and costs;

(ii) the related estimated net present value; and

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

(b) (i) both proved, and proved and probable conventional crude oil, NGL and natural gas reserve quantities estimated as at December 31, 2005 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, 2005.

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 evaluator 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.

/s/ Steve W. Laut

Steve W. Laut
President and Chief Operating Officer

/s/ Douglas A. Proll

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

/s/ David A. Tuer

David A. Tuer

Independent Director and Chair of the Reserve Committee

/s/ Norman F. McIntyre

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

Dated this 21st day of February, 2006
Calgary, Alberta

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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 to. All members of the Audit Committee shall have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements at the time of their appointment to the Audit Committee. At least one member of the Audit Committee shall have accounting or related financial

management expertise and qualify as a "financial expert" or similar designation in accordance with the requirements of the regulatory bodies to which the Corporation may be subject to.

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

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

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

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

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

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

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

7. The independent auditors and internal auditors shall have a direct line of communication to the Audit Committee through its chair and may bypass management if deemed necessary. Any employee may bring before the Audit Committee directly and may bypass management if

deemed necessary any matter involving questionable, illegal or improper financial practices or transactions.

III AUDIT COMMITTEE DUTIES AND RESPONSIBILITIES

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

   a. to assist the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and its approval of the Corporation's annual and quarterly consolidated financial statements;

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

   c. to ensure that the management of the Corporation has 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 for appointment by the shareholders, the Corporation's independent auditors, review the independence and 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 approve 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.

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 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 and report to the Board with respect thereto;

c. to review and approve regulatory filings and decisions as they relate to the Corporation's consolidated financial statements and related Management Discussion & Analysis and report to the Board thereto with respect to:

(i) the annual report to shareholders;
(ii) the annual information form;
(iii) the annual information form on Form 40-F;
(iv) prospectuses; and,
(v) other disclosure reports requiring approval by the Board;

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 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;

g. 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;

h. 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,

i. 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 Company's independent auditors in connection with the issuance of its audit report, or to any consultants or experts employed by the Audit Committee.

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THE PREMIUM VALUE,

DEFINED GROWTH, INDEPENDENT

[GRAPIC OMITTED]

[LOGO - CANADIAN NATURAL]

2005 ANNUAL REPORT

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

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

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

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to examine the consolidated financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the consolidated financial statements.

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

/s/ Steve W. Laut	/s/ Douglas A. Proll	/s/ Randall S. Davis
Steve W. Laut President & Chief Operating Officer February 21, 2006	Douglas A. Proll CA Senior Vice President, Finance & Chief Financial Officer	Randall S. Davis CA Vice President, Financial Accounting & Controls

A U D I T O R'S R E P O R T

TO THE SHAREHOLDERS OF CANADIAN NATURAL RESOURCES LIMITED,

We have audited the consolidated balance sheets of Canadian Natural Resources Limited as at December 31, 2005 and 2004 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three year period ended December 31, 2005. These consolidated 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 in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2005 in accordance with Canadian generally accepted accounting principles.

/s/ PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
February 21, 2006

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 10 to the consolidated financial statements. Our report to the shareholders dated February 21, 2006 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' report when the change is properly accounted for and adequately disclosed in the consolidated financial statements.

/s/ PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
February 21, 2006

CONSOLIDATED BALANCE SHEETS

As at DECEMBER 31 (millions of Canadian dollars)	2005	2004
ASSETS		
Current assets		
Cash and cash equivalents	$ 18	$ 28
Accounts receivable and other	1,546	1,055
Future income tax (note 6)	487	83
Current portion of other long-term assets (note 2)	-	34
	2,051	1,200
Property, plant and equipment (note 3)	19,694	17,064
Other long-term assets (note 2)	107	108
	$ 21,852	$ 18,372
LIABILITIES		
Current liabilities		
Accounts payable	$ 573	$ 379
Accrued liabilities	1,781	1,019
Current portion of long-term debt (note 4)	-	194
Current portion of other long-term liabilities (note 5)	1,471	260
	3,825	1,852
Long-term debt (note 4)	3,321	3,538
Other long-term liabilities (note 5)	1,434	1,208
Future income tax (note 6)	5,035	4,450
	13,615	11,048
SHAREHOLDERS' EQUITY		
Share capital (note 7)	2,442	2,408
Retained earnings	5,804	4,922
Foreign currency translation adjustment (note 8)	(9)	(6)
	8,237	7,324
	$ 21,852	$ 18,372

COMMITMENTS (note 11)

Approved by the Board of Directors:

/s/ Catherine M. Best
Catherine M. Best
Chair of the Audit Committee and Director

/s/ N. Murray Edwards
N. Murray Edwards
Vice-Chairman of the Board of Directors and Director

CONSOLIDATED STATEMENTS OF EARNINGS

For the years ended December 31 (millions of Canadian dollars, except per common share amounts)	2005	2004
Revenue	$ 10,107	$ 7,547
Less: royalties	(1,366)	(1,011)
Revenue, net of royalties	8,741	6,536
Expenses		
Production	1,663	1,400
Transportation	270	250
Depletion, depreciation and amortization	2,013	1,769
Asset retirement obligation accretion (note 5)	69	51
Administration	151	125
Stock-based compensation (note 5)	723	249
Interest, net	149	189
Risk management activities (note 10)	1,952	434
Foreign exchange gain	(132)	(91)
	6,858	4,376
Earnings before taxes	1,883	2,160
Taxes other than income tax (note 6)	194	165
Current income tax (note 6)	286	116
Future income tax (note 6)	353	474
Net earnings	$ 1,050	$ 1,405
Net earnings per common share (note 9)		
Basic	$ 1.96	$ 2.62
Diluted	$ 1.95	$ 2.60

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

For the years ended December 31 (millions of Canadian dollars)	2005	2004
Balance - beginning of year	$ 4,922	$ 3,650
Net earnings	1,050	1,405
Dividends on common shares (note 7)	(127)	(107)
Purchase of common shares under Normal Course Issuer Bid (note 7)	(41)	(26)
Balance - end of year	$ 5,804	$ 4,922

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 (millions of Canadian dollars)	2005	2004
Operating activities		
Net earnings	$ 1,050	$ 1,405
Non-cash items		
Depletion, depreciation and amortization	2,013	1,769
Asset retirement obligation accretion	69	51
Stock-based compensation	723	249
Unrealized risk management activities	925	(40)
Unrealized foreign exchange gain	(103)	(94)
Deferred petroleum revenue tax recovery	(9)	(45)
Future income tax	353	474
Deferred charges	(31)	(33)
Abandonment expenditures	(46)	(32)
Net change in non-cash working capital (note 12)	(147)	(14)
	4,797	3,690
Financing activities		
(Repayment) issue of bank credit facilities	(435)	357
Issue (repayment) of medium-term notes	400	(125)
Repayment of senior unsecured notes	(194)	(54)
Repayment of preferred securities	(107)	-
Issue of US dollar debt securities	-	830
Repayment of obligations under capital leases	-	(7)
Dividends on common shares	(121)	(101)
Issue of common shares on exercise of stock options	9	24
Purchase of common shares	(45)	(33)
Net change in non-cash working capital (note 12)	19	6
	(474)	897
Investing activities		
Expenditures on property, plant and equipment	(5,340)	(4,582)
Net proceeds on sale of property, plant and equipment	454	7
Net expenditures on property, plant and equipment	(4,886)	(4,575)
Net proceeds on sale of other assets	11	-
Net change in non-cash working capital (note 12)	542	(88)
	(4,333)	(4,663)
(Decrease) increase in cash	(10)	(76)
Cash - beginning of year	28	104
Cash - end of year	$ 18	$ 28

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 operations are focused in North America, largely in western Canada, the United Kingdom portion of the North Sea and Offshore West Africa. Within western Canada, the Company is developing its Horizon Oil Sands Project (the "Horizon Project") and maintains its midstream activities. The Horizon Project involves a plan to recover bitumen through mining operations, while the midstream activities include the Company's 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 15.

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 subsidiaries 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.

Depletion, depreciation and amortization, and amounts used for ceiling test 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. Substantially all of the Company's reserve estimates are evaluated annually by independent engineering firms. By their nature, estimates of reserves and the related future cash flows 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 measurement of petroleum revenue tax expense 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 of three months or less are reported as cash equivalents on the balance sheet.

(D) PROPERTY, PLANT AND EQUIPMENT

The Company follows the full cost method of accounting for crude oil and natural gas properties and equipment as prescribed 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 phase of 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 profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country.

Contractual arrangements that meet the definition of a lease as specified in Emerging Issues Committee ("EIC") 150 - "Determining Whether an Arrangement Contains a Lease" are accounted for as capital leases or operating leases as appropriate.

For mining activities, property acquisition, construction and development costs are capitalized. The Company reviews the recoverability of the carrying amount of its mining properties when events or circumstances indicate that the carrying amounts may not be recoverable.

(E) DEPLETION, DEPRECIATION AND AMORTIZATION

Costs related to each 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. Certain costs for major development projects 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 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 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.

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.

Head office capital assets are amortized on a declining balance basis over their estimated useful lives.

(F) CAPITALIZED INTEREST

Beginning in 2005, following the Board of Directors' approval of the Horizon Project, the Company commenced capitalization of construction period interest based on costs incurred and the Company's cost of borrowing. Interest capitalization will cease once construction is substantially complete and the Horizon Project is available for its intended use.

(G) DEFERRED CHARGES

Deferred charges primarily include deferred financing costs associated with the issuance of long-term debt and settlement costs of long-term natural gas contracts. Deferred charges are amortized over the original term of the related instrument.

(H) ASSET RETIREMENT OBLIGATIONS

The Company provides for future asset retirement obligations on its resource properties, facilities, production platforms and gathering system 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 life of the asset. 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.

(I) 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 the foreign currency translation adjustment 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 items. Gains or losses on translation are included in the consolidated statement of earnings.

Gains or losses on the translation of long-term debt denominated in US dollars are either recognized in net earnings immediately, or in the foreign currency translation adjustment (note 8) for translation gains or losses for that portion of the US dollar denominated debt designated as a hedge of self-sustaining foreign operations.

(J) REVENUE RECOGNITION

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer and delivery has taken place. 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.

(K) TRANSPORTATION COSTS

Transportation costs incurred to transport crude oil and natural gas to customers are recorded as a separate cost in the consolidated statement of earnings.

(L) PRODUCTION SHARING CONTRACT

Production generated from Offshore West Africa is currently shared under the terms of various Production Sharing Contracts ("PSC"). Revenues are divided into cost recovery revenues and profit revenues. Cost recovery revenues allow the Company to recover its share and the government's share of capital and operating costs carried by the Company. Profit revenues are allocated to the Company in accordance with its respective equity interest, after a portion has been allocated to the government. Cost recovery and profit revenues are reported as sales revenues. The government's share of revenues attributable to the Company's equity interest, except for income tax, is reported as a royalty expense in accordance with the PSCs.

(M) PETROLEUM REVENUE TAX

The Company accounts for the United Kingdom petroleum revenue tax ("PRT") by the life-of-the-field method. The total future liability or recovery of PRT is estimated using current reserves and anticipated sales prices and costs. The estimated future PRT is apportioned to accounting periods on the basis of total estimated future operating income. Changes in the estimated total future PRT are accounted for prospectively.

(N) 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 on 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.

(O) STOCK-BASED COMPENSATION PLANS

The Company accounts for its stock-based compensation plans using the intrinsic value method. The Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or 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. This liability is revalued at each reporting date to reflect changes in the market price of the Company's common shares, 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.

(P) 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 used for trading or speculative purposes. Changes in fair value of derivative financial instruments designated as hedges are not recognized in net earnings until such time as the corresponding gains or losses on the related hedged items are also recognized. Changes in fair value of derivative financial instruments not designated as hedges are recognized in the balance sheet each period with the offset reflected in risk management activities in the consolidated statements of earnings.

The Company formally documents all 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 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. Gains or losses on these contracts are included in risk management activities.

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. Gains or losses on interest rate swap contracts designated as hedges are included in interest expense. Gains or losses on non-designated interest rate contracts are included in risk management activities.

Cross currency swap agreements 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. Gains or losses on cross currency swap contracts designated as hedges are included in interest expense.

Gains or losses on the termination of financial instruments that have been accounted for as hedges are deferred under other assets or liabilities on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged transaction 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 net earnings. Gains or losses on the termination of financial instruments that have not been accounted for as hedges are recognized in net earnings immediately.

(Q) 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 included as a liability are used to purchase common shares at the average market price during the year. The dilutive effect of 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.

(R) RECENTLY ISSUED ACCOUNTING STANDARDS UNDER CANADIAN GAAP

FINANCIAL INSTRUMENTS

In January 2005, the CICA issued four new standards relating to the accounting for and disclosure of financial instruments.

- Section 3855 -- "Financial Instruments -- Recognition and Measurement" prescribes when a financial asset, financial liability, or non-financial derivative is to be recognized on the balance sheet as well as its measurement amount. This Section also specifies how financial instruments gains and losses are to be presented. Transitional provisions for this Section vary based on the type of financial instruments under consideration.

- Section 3865 -- "Hedges" expands on existing Accounting Guideline 13 -- "Hedging Relationships," and Section 1650 "Foreign Currency Translation," by specifying how hedge accounting is to be applied and what disclosures are necessary when it is applied. Retroactive application of this Section is not permitted.

- Section 1530 - "Comprehensive Income" introduces new standards for reporting and disclosure of comprehensive income. 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 those resulting from investments by owners and distributions to owners. Financial statements of prior periods are required to be restated only for non-financial instrument items.

- Section 3251 - "Equity" replaces Section 3250 "Surplus" and establishes standards for the presentation of equity and changes in equity during a reporting period. Financial statements of prior periods are required to be restated only for non-financial instrument items. For all other items, comparative financial statements presented are not restated, but an adjustment to the opening balance of accumulated other comprehensive income may be required.

The Company plans to adopt these new standards for interim and annual financial statements effective January 1, 2007. The effect on the Company's consolidated financial statements cannot be reasonably determined at this time as the financial derivatives outstanding at December 31, 2006 and their related fair values are not known.

(S) COMPARATIVE FIGURES
Certain figures provided for prior years have been reclassified to conform to the presentation adopted in 2005. Common share data has been restated to reflect the two-for-one share split in May 2005.

2. OTHER LONG-TERM ASSETS

Deferred charges	$
Risk management (note 10)	
Less: current portion	
	$

3. PROPERTY, PLANT AND EQUIPMENT

	2005				
	Cost	Accumulated depletion and depreciation	Net	Cost	Accu de depre
Crude oil and natural gas					
North America	$ 22,258	$ 7,948	$ 14,310	$ 19,750	$
North Sea	2,703	1,022	1,681	2,550	
Offshore West Africa	1,547	294	1,253	1,091	
Other	27	14	13	22	
Horizon Project	2,169	-	2,169	672	
Midstream	251	48	203	241	
Head office	124	59	65	101	
	$ 29,079	$ 9,385	$ 19,694	$ 24,427	$

During the year ended December 31, 2005, the Company capitalized administrative overhead of $41 million (2004 - $49 million, 2003 - $35 million) relating to exploration and development in the North Sea and Offshore West Africa and $236 million (2004 - $35 million, 2003 - $23 million) in North America, primarily related to the Horizon Project.

During the year ended December 31, 2005, the Company capitalized $72 million (2004 and 2003 - $nil) in construction period interest costs related to the Horizon Project.

Included in property, plant and equipment are unproved properties and major development projects that are not subject to depletion or depreciation:

Crude oil and natural gas	
North America	$
North Sea	
Offshore West Africa	
Other	
Horizon Project	
	$

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The Company has used the following estimated benchmark future prices ("escalated pricing") in its ceiling test prepared in accordance with Canadian GAAP, as at December 31, 2005:

	2006	2007	2008	2009
Crude oil and NGLs				
North America				
WTI at Cushing (US$/bbl)	$ 60.81	$ 61.61	$ 54.60	$ 50.19
Hardisty Heavy 12(degree) API (C$/bbl)	$ 37.07	$ 37.29	$ 34.23	$ 32.27
Edmonton Par (C$/bbl)	$ 70.07	$ 70.99	$ 62.73	$ 57.53
North Sea and Offshore West Africa				
North Sea Brent (US$/bbl)	$ 58.81	$ 59.58	$ 52.54	$ 48.10
Natural gas				
North America				
Henry Hub Louisiana (US$/mmbtu)	$ 11.59	$ 10.11	$ 8.50	$ 7.58
AECO (C$/mmbtu)	$ 11.58	$ 10.84	$ 8.95	$ 7.87
Huntingdon/Sumas (C$/mmbtu)	$ 11.34	$ 10.70	$ 8.81	$ 7.73

4. LONG-TERM DEBT

Bank credit facilities

Bankers' acceptances
US dollar bankers' acceptances (2005 - US$nil, 2004 - US$471 million)

Medium-term notes
7.40% unsecured debentures due March 1, 2007
4.95% unsecured debentures due June 1, 2015

Senior unsecured notes
7.69% due December 19, 2005 (2005 - US$nil, 2004 - US$125 million)
Adjustable rate due May 27, 2009 (2005 - US$93 million, 2004 - US$93 million)

Preferred securities
8.30% due June 25,2011 (2005 - US$nil, 2004 - US$80 million)

US dollar debt securities
6.70% due July 15, 2011 (2005 - US$400 million, 2004 - US$400 million)
5.45% due October 1, 2012 (2005 - US$350 million, 2004 - US$350 million)
4.90% due December 1, 2014 (2005 - US$350 million, 2004 - US$350 million)
7.20% due January 15, 2032 (2005 - US$400 million, 2004 - US$400 million)
6.45% due June 30, 2033 (2005 - US$350 million, 2004 - US$350 million)
5.85% due February 1, 2035 (2005 - US$350 million, 2004 - US$350 million)

Less: current portion of long-term debt

BANK CREDIT FACILITIES

As at December 31, 2005 the Company had in place unsecured syndicated bank credit facilities of $3,425 million, comprised of:

- a $100 million operating demand facility;
- a two-tranche revolving credit and term loan facility of $1,825 million; and
- a 5-year revolving and term loan facility of $1,500 million.

The first $1,000 million tranche of the $1,825 million facility is fully revolving for a period of three years to June 2008. The second tranche of $825 million is fully revolving for a period of five years to June 2010. Both tranches are extendible annually for one-year periods at the mutual agreement of the Company and the lenders. If not extended, the full amount of the outstanding principal would be repayable at the end of year two following the initiation of the term period. The $1,500 million revolving credit and term loan facility has a five-year term, with three, one-year extension provisions. If the facility is not extended, the amount outstanding would be repayable in December 2009. These facilities provide that the borrowings may be made by way of operating advances, prime loans, bankers' acceptances, US base rate loans or US dollar LIBOR advances, which bear interest at the bank's prime rates or at money market rates plus applicable margins.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2005, was 5.44% (2004 - 3.47%). The Company also has a (pound)15 million demand overdraft credit facility related to the Company's North Sea operations. At December 31, 2005 there were no amounts drawn on this facility.

In addition to the outstanding debt, as at December 31, 2005 letters of credit aggregating $24 million (2004 - $24 million) have been issued.

MEDIUM-TERM NOTES
In May 2005, the Company issued $400 million of debt securities maturing June 2015, bearing interest at 4.95%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

In May 2004, the Company repaid the $125 million 6.85% unsecured debentures due May 2004, which were issued under a previous medium-term note program.

In January 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. After issuing these securities, the Company has $1.6 billion remaining on its $2 billion shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

SENIOR UNSECURED NOTES
In December 2005, the Company repaid the US$125 million 7.69% senior unsecured notes. The 6.42% senior unsecured notes were repaid in May 2004.

The adjustable rate senior unsecured notes bear interest at 6.54% and have annual principal repayments of US$31 million commencing in May 2007, through May 2009.

PREFERRED SECURITIES
In September 2005, the Company redeemed the US$80 million 8.30% preferred securities due May 25, 2011 for cash consideration of US$91 million, including an early repayment premium of US$11 million as required under the Note Purchase Program.

US DOLLAR DEBT SECURITIES
In June 2005, the Company filed a short form prospectus that allows for the issue of up to US$2 billion of debt securities in the United States until July 2007. If issued, these securities will bear interest determined as at the date of issuance.

In December 2004, the Company issued US$350 million of debt securities maturing December 2014, bearing interest at 4.90% and US$350 million of debt securities maturing February 2035, bearing interest at 5.85%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. The Company has entered into certain interest rate swap contracts to convert the fixed rate interest coupon into a floating interest rate on the securities due December 2014 (note 10).

REQUIRED DEBT REPAYMENTS

Required debt repayments are as follows:

Year	Repayment
2006	$ -
2007	$ 161
2008	$ 36
2009	$ 36
2010	$ -

Thereafter	$ 2,966

No debt repayments are reflected for the bank credit facilities due to the extendable nature of the facilities.

5. OTHER LONG-TERM LIABILITIES

	2005	2004
Asset retirement obligations	$ 1,112	$ 1,119
Stock-based compensation	891	323
Risk management (note 10)	885	26
Other	17	-
	2,905	1,468
Less: current portion	1,471	260
	$ 1,434	$ 1,208

ASSET RETIREMENT OBLIGATIONS

At December 31, 2005, the Company's total estimated undiscounted costs to settle its asset retirement obligations with respect to crude oil and natural gas properties and facilities was approximately $3,325 million (2004 - $3,060 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 an average credit-adjusted risk-free interest rate of 6.8%. A reconciliation of the discounted asset retirement obligations is as follows:

	2005	2004
Asset retirement obligations		
Balance - beginning of year	$ 1,119	$ 897
Liabilities incurred	47	339
Liabilities settled	(46)	(32)
Asset retirement obligation accretion	69	51
Revision of estimates	(56)	(86)
Foreign exchange	(21)	(50)
Balance - end of year	$ 1,112	$ 1,119

The Company's pipelines have an indeterminant 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 first year in which the lives of the assets are determinable.

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 12-month period if all vested options are surrendered for cash settlement.

	2005	2004
Stock-based compensation		
Balance - beginning of year	$ 323	$ 171
Stock-based compensation provision	723	249
Cash payment for options surrendered	(227)	(80)
Transferred to common shares	(29)	(38)
Capitalized to Horizon Project	101	21
Balance - end of year	891	323
Less: current portion of stock-based compensation	629	243
	$ 262	$ 80

6. TAXES

TAXES OTHER THAN INCOME TAX

	2005	2004	2003
Current petroleum revenue tax	$ 181	$ 190	$ 106
Deferred petroleum revenue tax recovery	(9)	(45)	(9)
Provincial capital taxes and surcharges	22	20	10
	$ 194	$ 165	$ 107

INCOME TAX

The provision for income tax is as follows:

	2005	2004	2003
Current income tax expense			
Current income tax - North America	$ 82	$ 89	$ 43
Large Corporations Tax - North America	16	11	16
Current income tax - North Sea	155	2	23
Current income tax - Offshore West Africa	32	13	10
Current income tax - other	1	1	-
	286	116	92
Future income tax expense	353	474	338
Income tax	$ 639	$ 590	$ 430

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:

	2005	2004	
Canadian statutory income tax rate	38.0%	39.3%	
Income tax provision at statutory rate	$ 716	$ 849	$
Effect on income taxes of:			
Non-deductible portion of Canadian crown payments	309	221	
Canadian resource allowance	(293)	(270)	
Large Corporations Tax	16	11	
Deductible UK petroleum revenue tax	(65)	(57)	
Foreign tax rate differentials	(1)	(31)	
Federal income tax rate reductions	-	-	
Provincial income tax rate reductions	(19)	(66)	
Non-taxable portion of foreign exchange	(15)	(36)	
Attributed Canadian Royalty Income	(21)	(4)	
Other	12	(27)	
Income tax	$ 639	$ 590	$

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

	2005	
Future income tax liabilities		
Property, plant and equipment	$ 3,960	$
Timing of partnership items	1,646	
Unrealized foreign exchange gain on long-term debt	112	
Risk management activities	-	
Other	31	
Future income tax assets		
Asset retirement obligations	(384)	
Capital loss carryforwards	(79)	
Attributed Canadian Royalty Income	(75)	
Stock-based compensation	(300)	
Risk management activities	(304)	
Deferred petroleum revenue tax	(59)	
Future income tax liability	4,548	
Less: future income tax asset	(487)	
Net future income tax liability	$ 5,035	$

A significant portion of North America's taxable income is generated by partnerships. Income taxes are incurred on the partnerships' taxable income in the year following their inclusion in the Company's consolidated net earnings. Current income tax will vary and is dependent upon the nature and amount of capital expenditures incurred in Canada.

During 2005, the Government of British Columbia enacted legislation to reduce its corporate income tax rate by 1.5%, effective July 1, 2005, resulting in a $19 million reduction in the Company's future income tax liability.

During 2004, the Government of Alberta enacted legislation to reduce its corporate income tax rate by 1.0% effective April 1, 2004, resulting in a $66 million reduction in the Company's future income tax liability.

During 2003, the Government of Alberta enacted legislation to reduce its corporate income tax rate by 0.5% effective April 1, 2003. Also during 2003, the Canadian federal government enacted legislation to change the taxation of resource income. The legislation reduces 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 is being phased out and a deduction for actual crown royalties paid is being phased in. The Company's future income tax liability was reduced by $31 million with respect to the Alberta corporate income tax rate reduction and by $247 million with respect to the federal resource income tax rate changes.

7. SHARE CAPITAL

AUTHORIZED

200,000 Class 1 preferred shares with a stated value of $10.00 each.
Unlimited number of common shares without par value.

ISSUED

	2005		
Common shares	Numbers of shares (thousands)	Amount	Num (th
Balance - beginning of year	536,361	$ 2,408	
Issued upon exercise of stock options	837	9	
Previously recognized liability on stock options exercised for common shares	-	29	
Purchase of common shares under Normal Course Issuer Bid	(850)	(4)	
Balance - end of year	536,348	$ 2,442	

SHARE SPLIT
The Company's shareholders approved a subdivision or share split of its issued and outstanding common shares on a two-for-one basis at the Company's Annual and Special Meeting held on May 5, 2005. All common share and per common share amounts have been restated to retroactively reflect the share split.

NORMAL COURSE ISSUER BID
In January 2005, the Company announced the renewal of its Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase up to 26,818,012 common shares or 5% of the outstanding common shares of the Company on the date of announcement, during

the 12-month period beginning January 24, 2005 and ending January 23, 2006. As at December 31, 2005, the Company had purchased 850,000 common shares (2004 - 1,746,800 common shares) at an average price of $53.29 per common share (2004 - $19.00 per common share), for a total cost of $45 million (2004 - $33 million). Retained earnings was reduced by $41 million (2004 - $26 million), representing the excess of the purchase price of the common shares over their stated value.

On January 20, 2006, the Company announced the renewal of its Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase up to 26,852,545 common shares or 5% of the outstanding common shares of the Company on the date of the announcement, during the 12-month period beginning January 24, 2006 and ending January 23,2007. As at February 21, 2006, the Company had not purchased any additional shares under the Normal Course Issuer Bid.

DIVIDEND POLICY

The Company pays regular quarterly dividends in January, April, July and October of each year.

On February 21, 2006, the Board of Directors set the Company's regular quarterly dividend at $0.075 per common share (2005 - $0.059 per common share, 2004 - $0.050 per common share).

STOCK OPTIONS

The Option Plan provides for granting of stock options to employees. Stock options granted under the Option Plan have a maximum term of 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 permits the holder to purchase one common share of the Company at the stated exercise price.

In June 2003 the Company approved a modification to its Option Plan providing the stock option holder the right to elect to receive a cash payment equal to the difference between the exercise price of the stock option and the market price of the Company's common shares on the date of surrender, multiplied by the number of common shares covered by the stock options surrendered, in lieu of receiving common shares. The modification to the Option Plan was accounted for prospectively.

For the year ended December 31, 2005, the Company recorded stock-based compensation expense of $723 million (2004 - $249 million, 2003 - $200 million). In 2005, $101 million was capitalized to the Horizon Project (2004 - $21 million, 2003 - $10 million). As at December 31, 2005, the total liability for expected cash settlements under the Option Plan was $891 million (2004 - $323 million), of which $629 million (2004 - $243 million) was included as a current liability. During the year ended December 31, 2005, cash payments of $227 million were made for 7,523,000 stock options surrendered (2004 - cash payments of $80 million for 7,562,000 stock options surrendered). The following table summarizes information relating to stock options outstanding at December 31, 2005 and 2004:

2005

	Stock options (thousands)	Weighted average exercise price	(th
Outstanding - beginning of year	32,522	$ 12.37	
Granted	7,959	$ 32.51	
Exercised for common shares	(837)	$ 9.81	
Surrendered for cash settlement	(7,523)	$ 10.49	
Forfeited	(1,611)	$ 19.36	
Outstanding - end of year	30,510	$ 17.79	
Exercisable - end of year	8,677	$ 11.21	

The range of exercise prices of stock options outstanding and exercisable at December 31, 2005 was as follows:

	Stock options outstanding			Sto
Range of exercise prices	Stock options outstanding (thousands)	Weighted average remaining term (years)	Weighted average exercise price	exer (th
$ 7.85 - $ 9.99	8,794	1.41	$ 9.63	
$10.00 - $14.99	6,690	2.50	$ 11.74	
$15.00 - $19.99	6,234	3.53	$ 17.07	
$20.00 - $24.99	1,568	4.82	$ 22.89	
$25.00 - $29.99	4,301	4.18	$ 26.26	
$30.00 - $34.99	1,449	4.84	$ 33.22	
$40.00 - $44.99	201	5.45	$ 40.25	
$45.00 - $49.99	251	5.54	$ 47.16	
$50.00 - $54.99	600	5.72	$ 54.43	
$55.00 - $59.35	422	5.88	$ 55.89	
	30,510	3.02	$ 17.79	

8. FOREIGN CURRENCY TRANSLATION ADJUSTMENT

The foreign currency translation adjustment represents the unrealized gain (loss) on the Company's net investment in self-sustaining foreign operations. Effective July 1, 2002, the Company designated certain US dollar denominated debt as a hedge against its net investment in US dollar-based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment.

Balance - beginning of year	$
Unrealized loss on translation of net investment	
Hedge of net investment with US dollar denominated debt, net of tax	
Balance - end of year	$

9. NET EARNINGS PER COMMON SHARE

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

	2005	
(thousands of shares)		
Weighted average common shares outstanding - basic	536,650	
Effect of dilutive stock options (1)	-	
Assumed settlement of preferred securities with common shares	1,775	
Weighted average common shares outstanding - diluted	538,425	
Net earnings	$ 1,050	$
Interest on preferred securities, net of tax	4	
Revaluation of preferred securities, net of tax	(2)	
Diluted net earnings	$ 1,052	$
Net earnings per common share		
Basic	$ 1.96	$
Diluted	$ 1.95	$

(1) The Option Plan described in note 7 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 effective from June 2003, the date of the modification.
(2) Restated to reflect two-for-one share split in May 2005.

10. FINANCIAL INSTRUMENTS

RISK MANAGEMENT

On January 1, 2004, the fair values of all outstanding derivative financial instruments that were not designated as hedges for accounting purposes were recorded on the consolidated balance sheet, with an offsetting net deferred revenue amount. Subsequent net changes in the fair value of non-designated financial instruments have been recognized on the consolidated balance sheet and in net earnings. The estimated fair value for all derivative financial instruments is based on third party indications.

As at December 31, 2005 and 2004, the estimated fair values of non-designated financial derivatives were comprised as follows:

	2005		
	Risk management mark-to-market	Deferred revenue	ma mark-t
Balance - beginning of year	$ 66	$ (26)	
Net cost of put options outstanding as at December 31	190	-	
Net change in fair value of financial instruments outstanding as at December 31	(943)	-	
Amortization of deferred revenue	-	18	
Balance - end of year	(687)	(8)	
Less: put premium financing obligations	(190)	-	
	(877)	(8)	
Less: current portion (1)	834	8	
	$ (43)	$ -	

(1) The Company has negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective option.

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

	2005
Net realized risk management loss	$ 1,027
Net unrealized risk management loss (gain)	925
	$ 1,952

As at December 31, 2005, the net unrecognized liability related to the estimated fair values of derivative financial instruments designated as hedges was $990 million (December 31, 2004 - net unrecognized asset of $33 million).

FINANCIAL CONTRACTS

The Company's financial instruments recognized in the consolidated balance sheets consist of cash, accounts receivable, accounts payable, accrued liabilities, risk management activities, stock-based compensation and long-term debt.

The estimated fair values of financial instruments have been determined based on the Company's assessment of available market information, appropriate valuation methodologies and 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.

The carrying value of cash, accounts receivable, accounts payable, accrued liabilities, stock-based compensation and long-term debt with variable interest rates approximate their fair value.

The estimated fair values of other financial instruments were as follows:

	2005		2004
	Carrying Value	Fair Value	Carrying Value
Asset (liability)			
Derivative financial instruments	$ (687)	$ (1,700)	$ 66
Fixed rate notes	$ (3,199)	$ (3,367)	$ (3,175)

COMMODITY PRICE RISK MANAGEMENT

The Company uses certain derivative financial instruments to manage its commodity price exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. The following summarizes transactions outstanding as at December 31, 2005:

	Remaining term	Volume	Average price
Crude oil			
Crude oil price collars	Jan 2006 - Dec 2006	167,644 bbl/d	US$38.26 - US$48.2
	Jan 2006 - Dec 2006	82,356 bbl/d	US$44.75 - US$76.9
	Jan 2006 - Dec 2006	22,000 bbl/d	C$46.53 - C$58.6
Crude oil puts (1)	Mar 2006 - Jul 2006	55,000 bbl/d	US$40.0
	Aug 2006 - Dec 2006	51,000 bbl/d	US$45.0
	Jan 2007 - Dec 2007	100,000 bbl/d	US$28.0
	Jan 2007 - Dec 2007	100,000 bbl/d	US$45.0
Brent differential swaps	Jan 2006 - Dec 2006	25,000 bbl/d	US$1.2
	Jan 2007 - Dec 2007	50,000 bbl/d	US$1.3

(1) Subsequent to year end, the Company settled 17,000 bbl/d of the US$40.00 put options for 2006 and purchased 100,000 bbl/d of US$50.00 put options for 2007.

	Remaining term	Volume	Average price
Natural gas			
AECO collars	Jan 2006 - Mar 2006	700,000 GJ/d	C$5.88 - C$8.78

Jan 2006 - Mar 2006	400,000 GJ/d	C$6.00 - C$12.2
Jan 2006 - Mar 2006	100,000 GJ/d	C$8.00 - C$27.7
Apr 2006 - Jun 2006	993,000 GJ/d	C$5.71 - C$8.13
Apr 2006 - Jun 2006	100,000 GJ/d	C$7.00 - C$14.1
Jul 2006 - Sep 2006	725,000 GJ/d	C$5.60 - C$7.59
Jul 2006 - Sep 2006	100,000 GJ/d	C$7.00 - C$14.1
Oct 2006 - Dec 2006	244,000 GJ/d	C$5.60 - C$7.59
Oct 2006 - Dec 2006	100,000 GJ/d	C$7.00 - C$14.1
Oct 2006 - Dec 2006	464,000 GJ/d	C$7.50 - C$18.8
Jan 2007 - Mar 2007	700,000 GJ/d	C$7.50 - C$18.8

Commodity related derivative financial instruments designated as hedges at December 31, 2005, were all classified as cash flow hedges.

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, 2005, the Company had the following interest rate swap contracts outstanding:

	Remaining term	Amount ($ millions)	Fixed rate
Interest rate			
Swaps - fixed to floating	Jan 2006 - Jan 2007	US$200 (2)	7.20%
	Jan 2006 - Oct 2012	US$350	5.45%
	Jan 2006 - Dec 2014	US$350	4.90%
Swaps - floating to fixed	Jan 2006 - Mar 2007	C$6	7.36%

(1) London Interbank Offered Rate
(2) Subsequent to year end the Company received approximately $1 million in settlement of the 7.20% fixed to floating rate swap.
(3) Canadian Deposit Overnight Rate

Interest rate related derivative financial instruments designated as hedges at December 31, 2005, were all 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. Cross currency swap agreements 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. The Company may also enter into foreign currency denominated financial instruments to manage future US dollar denominated crude oil and natural gas sales. The Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar-based self-sustaining foreign operations (note 8).

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 this risk by entering into sales contracts with only highly rated entities. In addition, 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. The Company is also exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with only highly rated financial institutions and other entities.

11. COMMITMENTS

The Company has committed to certain payments as follows:

	2006	2007	2008	2009	201
Product transportation and pipeline (1)	$ 195	$ 133	$ 148	$ 94	$ 85
Offshore equipment operating lease	$ 51	$ 51	$ 52	$ 51	$ 51
Offshore drilling	$ 132	$ 100	$ 35	$ --	$ --
Asset retirement obligations (2)	$ 82	$ 4	$ 4	$ 4	$ 7
Other (3)	$ 61	$ 62	$ 21	$ 29	$ 23

(1) During the year, the Company entered into a 25 year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, annual toll payments before operating costs will be approximately $35 million.
(2) Represents management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, production platform and pipelines, based on current legislation and industry operating practices.
(3) Consists of future expenditures related primarily to office lease, electricity and crude oil processing.

The Board of Directors has approved the construction costs for Phase 1 of the Horizon Project, which are budgeted to be $6.8 billion, including a contingency fund of $700 million, with $1.3 billion incurred in 2005, $2.6 billion to be incurred in 2006 and $2.9 billion to be incurred in 2007 and 2008.

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The Company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

12. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Changes in non-cash working capital were as follows:

		2005		2004		200
Decrease (increase) in non-cash working capital						
Accounts receivable and other	$	(498)	$	(329)	$	3
Accounts payable		196		39		12
Accrued liabilities		716		194		12
Net change in non-cash working capital	$	414	$	(96)	$	28
Relating to:						
Operating activities	$	(147)	$	(14)	$	(4
Financing activities		19		6		(1
Investing activities		542		(88)		34
	$	414	$	(96)	$	28
Other cash flow information:						
Interest paid	$	200	$	192	$	17
Taxes paid	$	430	$	218	$	5

13. SEGMENTED INFORMATION

The Company's 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 crude oil, natural gas liquids and natural gas.

The Company's Horizon Project has been classified as a separate segment. As the bitumen will be recovered through mining operations, this project constitutes a distinct segment from crude oil and natural gas activities. 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.

	Crude oil and natural gas						
	North America			North Sea			Offshore
	2005	2004	2003	2005	2004	2003	2005

Segmented revenue	$ 7,932	$ 5,979	$ 5,021	$ 1,659	$ 1,317	$ 953	$ 485	$
Less: royalties	(1,350)	(1,003)	(868)	(3)	(2)	1	(13)	
Revenue, net of royalties	6,582	4,976	4,153	1,656	1,315	954	472	
Segmented expenses								
Production	1,211	976	845	379	370	314	53	
Transportation	287	256	264	20	32	30	--	
Depletion, depreciation and amortization	1,595	1,444	1,209	306	265	252	104	
Asset retirement obligation accretion	34	28	26	34	22	36	1	
Realized risk management activities	870	362	157	157	112	(9)	--	
Total segmented expenses	3,997	3,066	2,501	896	801	623	158	
Segmented earnings before the following	$ 2,585	$ 1,910	$ 1,652	$ 760	$ 514	$ 331	$ 314	$
Non-segmented expenses								
Administration								
Stock-based compensation								
Interest								
Unrealized risk management activities								
Foreign exchange gain								
Total non-segmented expenses								
Earnings before taxes								
Taxes other than income tax								
Current income tax expense								
Future income tax expense								
Net earnings								

	Midstream			Inter-segment elimination and other				
	2005	2004	2003	2005	2004	2003	2005	
Segmented revenue	$ 77	$ 68	$ 61	$ (46)	$ (39)	$ (35)	$10,107	$
Less: royalties	--	--	--	--	--	--	(1,366)	(
Revenue, net of royalties	77	68	61	(46)	(39)	(35)	8,741	
Segmented expenses								

Production	24	20	15	(4)	(2)	(3)	1,663
Transportation	--	--	--	(37)	(38)	(32)	270
Depletion, depreciation and amortization	8	7	7	--	--	--	2,013
Asset retirement obligation accretion	--	--	--	--	--	--	69
Realized risk management activities	--	--	--	--	--	--	1,027
Total segmented expenses	32	27	22	(41)	(40)	(35)	5,042
Segmented earnings before the following	$ 45	$ 41	$ 39	$ (5)	$ 1	$ --	$ 3,699 $
Non-segmented expenses							
Administration							151
Stock-based compensation							723
Interest							149
Unrealized risk management activities							925
Foreign exchange gain							(132)
Total non-segmented expenses							1,816
Earnings before taxes							1,883
Taxes other than income tax							194
Current income tax expense							286
Future income tax expense							353
Net earnings							$ 1,050 $

CAPITAL EXPENDITURES

	2005			
	Cash expenditures	Non-cash and fair value adjustments(1)	Capitalized costs	Cash expenditures
Crude oil and natural gas				
North America	$ 2,530	$ (22)	$ 2,508	$ 3,329
North Sea	387	(136)	251	608
Offshore West Africa	439	27	466	295
Other	5	--	5	1
	3,361	(131)	3,230	4,233

Horizon Project	1,499	--	1,499	291
Midstream	4	--	4	16
Head office	22	--	22	35
	$ 4,886	$ (131)	$ 4,755	$ 4,575

(1) Asset retirement obligations, future income tax adjustments on non-tax base assets, and other fair value adjustments.

Segmented property, plant and equipment, net	
Crude oil and natural gas	
North America	$
North Sea	
Offshore West Africa	
Other	
Horizon Project	
Midstream	
Head office	
	$

Segmented assets	
Crude oil and natural gas	
North America	$
North Sea	
Offshore West Africa	
Other	
Horizon Project	
Midstream	
Head office	
	$

14. BUSINESS COMBINATIONS

PETROVERA PARTNERSHIP

In February 2004, the Company acquired certain resource properties in its Northern Plains core region, collectively known as the Petrovera Partnership ("Petrovera"), for $471 million.

The acquisition was accounted for based on the purchase method. Results from Petrovera are consolidated with the results of the Company effective from the date of acquisition. The allocation of the purchase price to assets acquired and liabilities assumed based on their fair values was as follows:

	FEBRUARY 1, 2004
Purchase price:	
Cash consideration	$ 467
Cash acquired	(23)

Non-cash working capital deficit assumed		27
Total purchase price	$	471
Purchase price allocated as follows:		
Property, plant and equipment	$	643
Future income tax liability		(129)
Asset retirement obligation		(43)
	$	471

15. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company's consolidated financial statements have been prepared in accordance with generally accepted accounting principles in Canada ("Canadian GAAP"). These principles conform in all material respects with those in the United States ("US GAAP") except for those noted below. 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:

(millions of Canadian dollars, except per common share amounts)	Notes	2005	
Net earnings - Canadian GAAP		$ 1,050	$
Adjustments			
Depletion, net of tax of $3 million (2004 - $2 million; 2003 - $3 million)	(A)	4	
Derivative financial instruments and hedging activities, net of tax of $11 million (2004 - $7 million; 2003 - $20 million)	(B)	(19)	
Capitalized interest, net of tax of $11 million	(C)	--	
Cumulative effect of change in accounting policy, net of tax of $3 million	(D)	--	
Net earnings - US GAAP		$ 1,035	$
Net earnings - US GAAP per common share			
Basic		$ 1.93	$
Diluted		$ 1.93	$

Comprehensive income under US GAAP would be as follows:

(millions of Canadian dollars)	Notes	2005	
Net earnings - US GAAP		$ 1,035	$
Derivative financial instruments and hedging activities, net of tax of $312 million (2004 - $3 million; 2003 - $9 million)	(B)	(635)	
Foreign currency translation adjustment	(E)	(3)	
Comprehensive income		$ 397	$

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

		20	
(millions of Canadian dollars)	Notes	Canadian GAAP	Inc (dec
Current assets	(B)	$ 2,051	$
Property, plant and equipment	(A,C)	19,694	
Other long-term assets		107	
		$ 21,852	$
Current liabilities	(B)	$ 3,825	$
Long-term debt	(B)	3,321	
Other long-term liabilities	(B)	1,434	
Future income tax	(A,B,C)	5,035	
Shareholders' equity	(B,E)	8,237	
		$ 21,852	$

		2	
(millions of Canadian dollars)	Notes	Canadian GAAP	Inc (dec
Current assets	(B)	$ 1,200	$
Property, plant and equipment	(A,C)	17,064	
Other long-term assets		108	
		$ 18,372	$
Current liabilities	(B)	$ 1,852	$
Long-term debt		3,538	
Other long-term liabilities		1,208	
Future income tax	(A,B,C)	4,450	
Shareholders' equity	(B,E)	7,324	
		$ 18,372	$

NOTES:

(A) Under Canadian full cost accounting rules, costs capitalized in each cost centre, net of future income taxes, 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%.

(B) The Company accounts for its derivative financial instruments under Canadian GAAP as described in note 1(P). For US GAAP purposes, Financial Accounting Standards Board Statement ("FAS") 133, "Accounting for Derivative Financial Instruments and Hedging Activities," as amended by FAS 138 and FAS 149, establishes US GAAP accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. Generally, all derivatives, whether designated in hedging relationships or not, and excluding normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in the consolidated statements of earnings each period. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income ("OCI") each period and are recognized in the consolidated statements of earnings when the hedged item is recognized. Therefore, ineffective portions of changes in the fair value of hedging instruments are recognized in net earnings immediately for both fair value and cash flow hedges.

The determination of hedge effectiveness and the measurement of hedge ineffectiveness of cash flow hedges is based on a combination of third party indications and internally derived valuations. The Company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

(C) 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 has been capitalized to the costs of construction beginning in 2004.

(D) Under Canadian GAAP, when the asset retirement obligation standard was adopted prior period comparative balances were restated to reflect the effect of the new standard on that year. Under US GAAP, when the asset retirement obligation standard was adopted the cumulative effect of the new standard on prior periods was included in earnings in the year adopted.

(E) Under US GAAP, exchange gains and losses arising from the translation of self-sustaining foreign operations are included in comprehensive income.

(F) Recently issued accounting standards under US GAAP:

SHARE-BASED PAYMENT

In December 2004, the Financial Accounting Standards Board ("FASB") issued FAS

123(R) "Share-Based Payment," which is a revision of FAS 123. This standard requires all companies to reflect stock based compensation in their statement of earnings for US GAAP. The fair value of stock options must be recognized at the date of grant using option pricing models. The fair value must be remeasured each quarter and changes in fair value must flow through the statement of earnings. This is a difference from Canadian GAAP, where the Company's options are valued at the difference between the exercise price and the stock price. This standard is effective for the first interim or annual reporting period of a registrant's first fiscal year beginning on or after June 15, 2005. The Company plans to adopt this standard January 1, 2006.

ACCOUNTING CHANGES AND ERROR CORRECTIONS

In May 2005, the FASB issued FAS 154 "Accounting Changes and Error Corrections," which replaces FAS 3 "Reporting Accounting Changes in Interim Financial Statements" and APB Opinion 20 "Accounting Changes." The previous standards required that changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. The new standard requires that accounting changes be applied retrospectively and that prior accounting periods be restated as if the accounting principle had always been used. This change eliminates a difference from Canadian GAAP. The new standard will be applied to all future US GAAP accounting policy changes.

MANAGEMENT'S DISCUSSION & ANALYSIS

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document or documents incorporated herein by reference for Canadian Natural Resources Limited (the "Company") may constitute "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such because of the context of the statements including words such as "believes", "anticipates", "expects", "plans", "estimates", or words of a similar nature.

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, 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; foreign currency exchange rates; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists or 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 availability and cost of seismic, drilling and other equipment; ability of the Company to complete its capital programs; ability of the Company to transport its products to market; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the ability of the Company to attract the necessary labour required to build its 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; success of exploration and development activities; timing and success of integrating the business and operations of acquired companies; production levels; uncertainty of reserve estimates; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); asset retirement obligations; and other circumstances affecting revenues and expenses. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent, and the Company's course of action would depend upon its assessment of the future considering all information then available.

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.

Readers are cautioned that the foregoing list of important factors is not exhaustive. 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 were 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 the Company'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 EBITDA (net earnings before interest, taxes, depreciation, depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activities). 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") 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, 2005. 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 15 to the consolidated financial statements. All dollar amounts are referenced in Canadian dollars, except where otherwise noted. Common share data has been restated to reflect the two-for-one share split in May 2005. 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 well head. Production volumes are the Company's interest before royalties, and realized prices exclude the effect of risk management activities, except where noted otherwise. The following discussion and analysis refers primarily to the

Company's 2005 financial results compared to 2004 and 2003, unless otherwise indicated. In addition, this discussion details the Company's capital program and outlook for 2006. This MD&A is dated February 21, 2006.

ABBREVIATIONS

AECO	Alberta natural gas reference location
AIF	Annual Information Form
bbl	barrel
bbl/d	barrels per day
BCF	billion cubic feet
bcf/d	billion cubic feet per day
BOE	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian dollars
FPSO	Floating Production, Storage and Offtake Vessel
GHG	Greenhouse Gas
Horizon Project	Horizon Oil Sands Project
mbbl	thousand barrels
mbbl/d	thousand barrels per day
mboe	thousand barrels of oil equivalent
mboe/d	thousand barrels of oil equivalent per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbbl	million barrels
mmboe	million barrels of oil equivalent
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	Securities and Exchange Commission
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US$	United States dollars
WCS	Western Canadian Select crude oil blend
WTI	West Texas Intermediate

OBJECTIVE AND STRATEGY

The Company's objective is 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 acquisition of new reserves. The Company accomplishes this objective by having a defined growth and a 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 wealth. The Company effectively allocates its capital by maintaining:

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

sheet.

(1) Discounted value of conventional crude oil and natural gas reserves and undeveloped land, less net debt.
(2) Pelican Lake crude oil is 14-17 (degree) API oil, but receives medium quality crude netbacks due to low operating costs and low royalty rates.

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

- Blending various crude oil streams with diluents into more attractive feedstock;
- Supporting and participating in pipeline expansion or new additions; and
- Supporting and participating in projects that will increase the conversion capacity of heavy crude oil.

Operational discipline and cost control is central to the Company's strategy. By controlling costs consistently throughout all cycles of the industry, the Company believes that it will achieve continued growth. Cost control is attained by developing area knowledge, by core area domination and by maintaining a high working interest in its properties.

The Company is committed to maintaining its strong financial position throughout construction of the Horizon Oil Sands Project ("Horizon Project"). The Company believes that it has built the necessary financial capacity to complete the Horizon Project while at the same time not compromising delivery from its conventional crude oil and natural gas growth opportunities. Additionally, the Company's risk management hedge program has been expanded to reduce the risk of volatility in commodity price markets and to support the Company's cash flow for its capital expenditures program throughout the construction period of the Horizon Project.

Strategic accretive acquisitions are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt to selectively acquire properties generating future cash flows in its core regions. These targeted acquisitions provide relatively quick repayment of initial investments and should provide additional free cash flow during the construction years of the Horizon Project while still achieving targeted returns.

The year ended December 31, 2005, was another successful year in the execution of the Company's strategy. Highlights are as follows:

- Maintained strong levels of net earnings;
- Achieved record levels of adjusted net earnings from operations;
- Achieved record levels of cash flow;
- Completed the disposition of a large portion of its overriding royalty interests, which were considered non-core to the Company's operations, for proceeds of approximately $345 million;
- Completed the subdivision of its common shares on the basis of two for one;
- Increased the quarterly dividend by 20% to $0.06 per common share;
- Purchased 850,000 common shares for a total cost of $45 million under the Company's Normal Course Issuer Bid;
- Achieved record levels of natural gas and crude oil and NGLs production;
- Achieved its annual production guidance for crude oil and NGLs, and natural gas;
- Completed the development of the 57.61% owned and operated Baobab Field offshore Cote d'lvoire West Africa, which commenced production on August 9, 2005 at approximately 30,000 bbl/d net to the Company;

- o Completed the acquisition of the permit to develop the Olowi Field, offshore Gabon, West Africa with development plans to proceed in 2006;
- o Received Board of Directors' approval of the Horizon Project and completed 19% of Phase 1 construction;

- o Signed a key pipeline transportation agreement, which will allow Horizon Project Synthetic Crude Oil ("SCO") to reach the pipeline hub at Edmonton, Alberta;
- o Completed all major 2005 milestones on the Horizon Project, before winter' onset;
- o Commenced steam injection at Primrose North. First oil production began in January 2006 and is expected to increase to 30,000 bbl/d by the third quarter of 2006;
- o Drilled a record 1,634 net wells, excluding stratigraphic test/service wells; and
- o Announced a strategy to review the building of a 100% owned and operated upgrader ("Canadian Natural Upgrader") for the Company's in-situ oil sands assets in the Cold Lake to Athabasca region.

NET EARNINGS AND CASH FLOW FROM OPERATIONS

FINANCIAL HIGHLIGHTS ($ millions, except per common share amounts)	2005	2004	200
Revenue, before royalties	$ 10,107	$ 7,547	$ 6,15
Net earnings	$ 1,050	$ 1,405	$ 1,40
Per common share			
- basic (1)	$ 1.96	$ 2.62	$ 2.6
- diluted (1)	$ 1.95	$ 2.60	$ 2.5
Adjusted net earnings from operations (2)	$ 2,034	$ 1,405	$ 98
Per common share			
- basic (1)	$ 3.79	$ 2.62	$ 1.8
- diluted (1)	$ 3.78	$ 2.60	$ 1.8
Cash flow from operations (3)	$ 5,021	$ 3,769	$ 3,16
Per common share			
- basic (1)	$ 9.36	$ 7.03	$ 5.8
- diluted (1)	$ 9.33	$ 6.98	$ 5.7
Dividends declared per common share	$ 0.236	$ 0.200	$ 0.15
Total assets	$ 21,852	$ 18,372	$ 14,64
Total long-term liabilities	$ 9,790	$ 9,196	$ 7,27
Capital expenditures, net of dispositions	$ 4,932	$ 4,633	$ 2,50

(1) Restated to reflect two-for-one share split in May 2005.

(2) Adjusted net earnings from operations is a non-GAAP term 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 following reconciliation 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.

($ millions)	2005	2004	200
Net earnings as reported	$ 1,050	$ 1,405	$ 1,40
Stock-based compensation, net of tax (a)	481	168	13
Unrealized risk management loss (gain), net of tax (b)	607	(27)	
Unrealized foreign exchange gain, net of tax (c)	(85)	(75)	(27
Effect of statutory tax rate changes on future income tax liabilities (d)	(19)	(66)	(27
Adjusted net earnings from operations	$ 2,034	$ 1,405	$ 98

(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, net of taxes, flow through net earnings.

(b) Effective January 1, 2004, the Company adopted a new accounting standard whereby financial instruments not designated as hedges are recorded at fair value on its balance sheet, with changes in fair value, net of taxes, 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 and are immediately recognized in net earnings.

(d) All substantively enacted adjustments in applicable income tax rates are applied to underlying assets and liabilities on the Company's 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. In 2005, the province of British Columbia enacted legislation to reduce its corporate income tax rate by 1.5%. During 2004, the province of Alberta enacted legislation to reduce its corporate income tax rate by 1%. During 2003 the province of Alberta enacted legislation to reduce its corporate income tax rate by 0.5%. Also during 2003, the Canadian federal government enacted legislation to change the taxation of resource income. The federal legislation reduces 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 is being phased out and a deduction of actual crown royalties paid is being phased in. The Company's future income tax liability was reduced by $31 million with respect to the Alberta corporate income tax rate reduction and by $247 million with respect to the federal resource income tax rate changes.

(3) Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. 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. Cash flow from operations may not be comparable to similar measures presented by other companies.

($ millions)	2005	2004	200
Net earnings	$ 1,050	$ 1,405	$ 1,40
Non-cash items:			
Depletion, depreciation and amortization	2,013	1,769	1,50
Asset retirement obligation accretion	69	51	6
Stock-based compensation	723	249	20
Unrealized risk management activities	925	(40)	
Unrealized foreign exchange gain	(103)	(94)	(34
Deferred petroleum revenue tax recovery	(9)	(45)	(
Future income tax	353	474	33
Cash flow from operations	$ 5,021	$ 3,769	$ 3,16

The Company achieved record levels of cash flow from operations and production in 2005 as a result of strong operational performance combined with increased commodity prices. The strong operating results are attributable to the Company following its defined growth strategy and to the strong asset base the Company has developed over time through organic growth and accretive acquisitions.

For the year ended December 31, 2005, the Company recorded net earnings of $1,050 million compared to net earnings of $1,405 million for the year ended December 31, 2004 (2003 - $1,403 million). Net earnings for 2005 include unrealized after-tax expenses of $984 million related to the Company's risk management activities and stock-based compensation plans, net of foreign exchange gains and the effect of statutory tax rate changes ($nil for 2004; 2003 -unrealized after-tax income of $416 million). Excluding the effects of these items, adjusted net earnings from operations increased 45% to $2,034 million from $1,405 million in 2004 (2003 - $987 million) due to continuing strong crude oil and natural gas prices as well as record levels of total sales on a boe basis, offset by realized risk management activities and the impact of a strengthening Canadian dollar.

Cash flow from operations reached record levels in 2005. Cash flow from operations increased 33% to $5,021 million ($9.36 per common share), up from $3,769 million ($7.03 per common share) in 2004 (2003 - $3,160 million or $5.88 per common share). The increase in cash flow from operations was due mainly to strong commodity prices and record levels of total sales volume on a boe basis, offset by realized risk management activities and the impact of a strengthening Canadian dollar. In 2005, the Company's average sales price per bbl of crude oil and NGLs increased 23% to $46.86 per bbl from $37.99 per bbl in 2004 (2003 - $32.66 per bbl). The Company's average natural gas price increased 32% to $8.57 per mcf from $6.50 per mcf in 2004 (2003 - $6.21 per mcf).

Production volumes before royalties increased 8% to a record 552,960 boe/d, up from 513,835 boe/d in 2004 (2003 - 458,814 boe/d). The increase in production was due to organic growth from the Company's extensive North America capital expenditure program and the commencement of production from the Baobob Field offshore Cote d'lvoire, as well as the full year impact of accretive acquisitions completed in 2004. Production of crude oil and NGLs before royalties increased 11% to 313,168 bbl/d, up from 282,489 bbl/d in 2004 (2003 - 242,392 bbl/d). Natural gas production before royalties increased 4% to 1,439 mmcf/d, up from 1,388 mmcf/d in 2004 (2003 - 1,299 mmcf/d).

OPERATING HIGHLIGHTS	2005	2004	200
CRUDE OIL AND NGLS ($/bbl) (1)			
Sales price (2)	$ 46.86	$ 37.99	$ 32.6
Royalties	3.97	3.16	2.7
Production expense	11.17	10.05	10.2
Netback	$ 31.72	$ 24.78	$ 19.6
NATURAL GAS ($/mcf) (1)			
Sales price (2)	$ 8.57	$ 6.50	$ 6.2
Royalties	1.75	1.35	1.3
Production expense	0.73	0.67	0.6
Netback	$ 6.09	$ 4.48	$ 4.2
BARREL OF OIL EQUIVALENT ($/boe) (1)			
Sales price (2)	$ 48.77	$ 38.45	$ 34.8
Royalties	6.82	5.37	5.2
Production expense	8.21	7.35	7.1
Netback	$ 33.74	$ 25.73	$ 22.4

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

SUMMARY OF QUARTERLY RESULTS
The following is a summary of the Company's quarterly results for the most recently completed quarters: ($ millions, except per common share amounts)

2005	TOTAL	DEC 31	SEP 30
Revenue, before royalties	$ 10,107	$ 3,032	$ 2,918
Net earnings (loss)	$ 1,050	$ 1,104	$ 151
Net earnings (loss) per common share			
- basic (1)	$ 1.96	$ 2.06	$ 0.28
- diluted (1)	$ 1.95	$ 2.06	$ 0.28

2004	TOTAL	DEC 31	SEP 30
Revenue, before royalties	$ 7,547	$ 1,969	$ 2,075
Net earnings	$ 1,405	$ 577	$ 311
Net earnings per common share			
- basic (1)	$ 2.62	$ 1.07	$ 0.58
- diluted (1)	$ 2.60	$ 1.06	$ 0.57

(1) Restated to reflect two-for-one share split in May 2005.

Quarterly revenues have steadily increased throughout 2004 and 2005. This trend reflects increasing world benchmark crude oil and natural gas prices and increasing sales volumes.

- Prices continued to reflect world-wide economic growth and persistent geopolitical uncertainty, further exacerbated by hurricane activity in the Gulf of Mexico during the third quarters of 2004 and 2005. As a result, the Company's realized crude oil and NGLs price increased from C$34.21 per bbl for the first quarter of 2004 to C$46.38 per bbl for the fourth quarter of 2005. The realized natural gas price increased from C$6.31 per mcf to C$11.67 per mcf for the same periods. A strengthening Canadian dollar relative to the US dollar offset the impact of increasing commodity prices. The US / Canadian dollar average exchange rate increased from 0.76 for the first quarter of 2004 to 0.84 for the fourth quarter of 2005.
- Strong sales volumes in 2005 versus 2004 were also fundamental to the steady increase in revenue, driven by North America's extensive capital program, the commencement of production from the Baobab Field offshore Cote d'lvoire in 2005, as well as the full year impact of accretive acquisitions completed late in 2004. Daily production increased from 476,944 boe/d day in the first quarter of 2004 to 577,505 boe/d for the fourth quarter of 2005.
- The Company acquired certain heavy crude oil properties in its Northern Plains core region in the first quarter of 2004.
- The Company completed the acquisition of certain resource properties located in Northeast British Columbia and Northwest Alberta in the second quarter of 2004. These properties include further ownership in the Ladyfern natural gas field.
- The Company acquired certain light crude oil producing properties in the Central North Sea in the third quarter of 2004. The acquired properties comprise operated interests in T-Block (Tiffany, Toni and Thelma Fields) and B-Block (Balmoral, Stirling and Glamis Fields).
- The Company completed the acquisition of certain resource properties located in Alberta, British Columbia and Saskatchewan in the fourth quarter of 2004.

In addition to commodity prices, sales volumes and acquisitions, net earnings continued to be impacted by:

- The impact of the mark-to-market ("MTM") treatment of the Company's commodity price contracts as part of its commodity hedging program. Steadily increasing commodity prices have resulted in significant realized and unrealized risk management losses as the Company strives to lock in prices and secure cash flow for its capital expenditure program.

- The MTM treatment on its stock-based compensation plan. The Company's strong stock performance has resulted in the recognition of significant stock-based compensation expense.
- Increasing production expense. Higher service costs as a result of increased industry-wide activity in reaction to higher commodity prices as well as the impact of higher crude oil prices on fuel related expenses have resulted in increased costs.
- Corporate income tax rates. During the first quarter of 2004, the North America future tax liability was reduced by $66 million as a result of a reduction in the Alberta corporate income tax rate from 12.5% to 11.5%. During the third quarter of 2005, the province of British Columbia enacted legislation to reduce its corporate income tax rate by 1.5% effective July 1, 2005. As a result, the North America future income tax liability was reduced by $19 million.

BUSINESS ENVIRONMENT

(Yearly average)	2005	2004	200
WTI benchmark price (US$/bbl) (1)	$ 56.61	$ 41.43	$ 31.0
Dated Brent benchmark price (US$/bbl)	$ 54.45	$ 38.28	$ 28.8
Differential to LLB blend (US$/bbl)	$ 20.83	$ 13.44	$ 8.5
Differential to LLB blend as a % of WTI	37%	32%	28
Condensate benchmark price (US$/bbl)	$ 57.25	$ 41.62	$ 31.4
NYMEX benchmark price (US$/mmbtu)	$ 8.56	$ 6.09	$ 5.4
AECO benchmark price (C$/GJ)	$ 8.05	$ 6.43	$ 6.3
US/Canadian dollar average exchange rate (US$)	0.8253	0.7683	0.713

(1) Refers to West Texas Intermediate crude oil barrel prices at Cushing, Oklahoma.

World light crude oil prices reached all-time highs in 2005, supported by:

- Strong demand growth, particularly in China, India and the United States;
- Ongoing geopolitical uncertainties in Iran, Nigeria, Iraq and Venezuela;
- Production losses in the Gulf of Mexico from hurricanes Katrina and Rita. Many platforms and refineries are not expected to be operational until sometime late in 2006; and
- Restricted crude oil refining capacity, which increased refiners' demand for light crude oil to maximize yields of gasoline and distillates.

West Texas Intermediate ("WTI") averaged US$56.61 per bbl for the year ended December 31, 2005, an increase of 37% compared to US$41.43 per bbl for the year ended December 31, 2004 (2003 - US$31.02 per bbl).

Higher WTI pricing is not fully reflected in the Company's crude oil price realizations. The positive impact of higher WTI prices on the Company's crude oil production continues to be mitigated by wider heavy crude oil differentials, which increased 55% to US$20.83 per bbl for the year ended December 31, 2005 from US$13.44 per bbl for the year ended December 31, 2004 (2003 - $US8.55 per bbl).

Heavy crude oil differentials in 2005 continued to be higher than the long-term average primarily due to physical limitations for demand at refineries. Following hurricanes Katrina and Rita, refiners sought to process lighter barrels to increase their yields of gasoline and distillates, which resulted in the further deterioration of heavy crude oil differentials. Plant turnarounds and maintenance during the year, additional problems at refineries and upgraders, the higher cost of diluents, and the stronger Canadian dollar also mitigated the effect of higher WTI prices on the Company's heavy crude oil price realizations. A strengthening in the Canadian dollar reduces the Canadian dollar sales price the Company receives for its crude oil production as crude oil prices are based on US dollar denominated benchmarks.

North American natural gas prices also climbed in 2005 due to concerns around supply as well as the impact of higher crude oil prices. NYMEX natural gas prices increased 41% to average US$8.56 per mmbtu for the year ended December 31, 2005, up from US$6.09 per mmbtu for the year ended December 31, 2004 (2003 - $5.44 per mmbtu). AECO natural gas pricing moved directionally with NYMEX, increasing 25% to average $8.05 per GJ for the year ended December 31, 2005, up from $6.43 per GJ for the year ended December 31, 2004 (2003 - $6.35 per GJ).

REVENUE, BEFORE ROYALTIES

Analysis of changes in revenue, before royalties

		Changes due to				C
($ millions)	2003	Volumes	Prices	Other	2004	Volumes
North America						
Crude oil and NGLs	$ 1,953	$ 342	$ 283	$ --	$ 2,578	$ 170
Natural gas	3,068	207	126	--	3,401	208
	5,021	549	409	--	5,979	378
North Sea						
Crude oil and NGLs	873	123	227	--	1,223	31
Natural gas	80	5	9	--	94	(59)
	953	128	236	--	1,317	(28)
Offshore West Africa						
Crude oil and NGLs	141	13	54	--	208	182
Natural gas	14	(1)	1	--	14	(6)
	155	12	55	--	222	176
Subtotal						
Crude oil and NGLs	2,967	478	564	--	4,009	383
Natural gas	3,162	211	136	--	3,509	143
	6,129	689	700	--	7,518	526
Midstream	61	--	--	7	68	--

Intersegment eliminations and other (1)	(35)	--	--	(4)	(39)	--
Total	$ 6,155	$ 689	$ 700	$ 3	$ 7,547	$ 526

(1) Eliminates primarily internal transportation and electricity charges.

Revenue rose 34% to $10,107 million in 2005, up from $7,547 million in 2004 (2003 - $6,155 million). Price increases accounted for 79% of the 2005 increase (2004 - 51%), while volume increases accounted for the remaining 21% (2004 - 49%).

In 2005, 21% of the Company's crude oil and natural gas revenue was generated outside of North America, up from 20% in 2004 (2003 - 18%). North Sea accounted for 16% of crude oil and natural gas revenue in 2005 and 17% in 2004 (2003 - 16%), and Offshore West Africa accounted for 5% of crude oil and natural gas revenue in 2005 and 3% in 2004 (2003 - 2%).

ANALYSIS OF PRODUCT PRICES (1)	2005	2004	200
CRUDE OIL AND NGLS ($/bbl) (2)			
North America	$ 39.62	$ 33.16	$ 29.4
North Sea	$ 66.57	$ 51.37	$ 42.0
Offshore West Africa	$ 59.91	$ 49.05	$ 36.4
Company average	$ 46.86	$ 37.99	$ 32.6
NATURAL GAS ($/mcf) (2)			
North America	$ 8.65	$ 6.61	$ 6.3
North Sea	$ 3.17	$ 3.73	$ 3.0
Offshore West Africa	$ 5.91	$ 5.25	$ 4.3
Company average	$ 8.57	$ 6.50	$ 6.2
Company average ($/boe) (2)	$ 48.77	$ 38.45	$ 34.8
PERCENTAGE OF REVENUE (excluding midstream revenue)			
Crude oil and NGLs	54%	54%	50%
Natural gas	46%	46%	50%

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

Realized crude oil prices increased 23% to average $46.86 per bbl in 2005, up from $37.99 per bbl in 2004 (2003 - $32.66 per bbl). This increase was primarily due to higher benchmark world crude oil prices, as well as an increased proportion of crude oil and NGLs sales coming from Offshore West Africa, offset by higher heavy crude oil differentials and a stronger Canadian dollar. Higher benchmark crude oil prices were primarily driven by increased demand in countries such as China, India and the United States as well as concerns around supply, which increased pricing volatility.

The Company's realized natural gas price increased 32% to average $8.57 per mcf in 2005, up from $6.50 per mcf in 2004 (2003 - $6.21 per mcf), primarily due to supply concerns and a continued strengthening in benchmark North America gas pricing.

NORTH AMERICA

North America realized crude oil prices increased 19% to average $39.62 per bbl in 2005, up from $33.16 per bbl in 2004 (2003 - $29.40 per bbl). The increase in the realized crude oil price in 2005 was mainly due to higher benchmark crude oil prices, partially offset by wider heavy crude oil differentials and the strengthening Canadian dollar.

North America 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 geographic markets, and working with refiners to add incremental heavy crude oil conversion capacity. As part of an industry initiative to develop new blends of Western Canadian crude oils, the Company has access to blending capacity of up to 140,000 bbl/d. The Company is currently contributing approximately 139,000 bbl/d of heavy crude oil blends to the Western Canadian Select ("WCS") stream, a new blend of up to 10 different crude oil streams. WCS resembles a Bow River type crude with distillation cuts approximating a natural heavy crude oil with premium quality asphalt characteristics and has an API of 19(degree)-22(degree). Volumes of the new blend are expected to grow, with the potential to become a new benchmark for North American markets in addition to WTI. The Company has committed to 25,000 bbl/d of capacity on the Corsicana Pipeline, which will carry crude oil to the Gulf of Mexico and is expected to be in operation late in the first quarter of 2006. The Corsicana Pipeline is made up of a series of segments extending from Patoka Illinois to Nederland Texas, near the US Gulf Coast.

North America realized natural gas prices increased 31% to average $8.65 per mcf for the year ended December 31, 2005, up from $6.61 per mcf for the year ended December 31, 2004 (2003 - $6.34 per mcf). This increase was due to supply concerns and fluctuations in the North America benchmark natural gas price in response to crude oil pricing.

A comparison of the price received for the Company's North America production is as follows:

	2005	2004	200
Wellhead price (1)(2)			
Light crude oil and NGLs (C$/bbl)	$ 58.41	$ 45.90	$ 37.5
Pelican Lake crude oil (C$/bbl)	$ 38.39	$ 32.12	$ 28.0
Primary heavy crude oil (C$/bbl)	$ 33.53	$ 28.99	$ 26.2
Thermal heavy crude oil (C$/bbl)	$ 32.29	$ 29.00	$ 25.5
Natural gas (C$/mcf)	$ 8.65	$ 6.61	$ 6.3

(1) Including transportation 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 30% to average $66.57 per bbl for the year ended December 31, 2005, up from $51.37 per bbl for the year ended December 31, 2004 (2003 - $42.00 per bbl). The increase in the realized crude oil price compared to 2004 was due mainly to higher world benchmark crude oil prices and a narrowing of the average Brent differential, offset by the strengthening Canadian dollar.

OFFSHORE WEST AFRICA

Offshore West Africa realized crude oil prices increased 22% to average $59.91 per bbl for the year ended December 31, 2005, an increase from $49.05 per bbl for the year ended December 31, 2004 (2003 - $36.47 per bbl). The increase in realized crude oil prices from 2004 was primarily due to higher world benchmark crude oil prices offset by the strengthening 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, referred to as "liftings" in this MD&A. For production where revenue has not yet been recognized, the related crude oil inventory volumes, by segment, were as follows at December 31, 2005:

(bbl)
North America, related to Corsicana pipeline line fill
North Sea, related to timing of liftings
Offshore West Africa, related to timing of liftings, net of government entitlement to profit oil

At December 31, 2004, variances between production volumes and liftings were not significant.

ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES	2005	2004	200
CRUDE OIL AND NGLS (bbl/d)			
North America	221,669	206,225	174,89
North Sea	68,593	64,706	56,86
Offshore West Africa	22,906	11,558	10,62
	313,168	282,489	242,39
NATURAL GAS (mmcf/d)			
North America	1,416	1,330	1,24
North Sea	19	50	4

Offshore West Africa	4	8	
	1,439	1,388	1,29
TOTAL BARREL OF OIL EQUIVALENT (boe/d)	552,960	513,835	458,81
PRODUCT MIX (%)			
Light crude oil and NGLs	26%	24%	25
Pelican Lake crude oil	4%	4%	5
Primary heavy crude oil	17%	19%	15
Thermal heavy crude oil	10%	8%	8
Natural gas	43%	45%	47

DAILY PRODUCTION, NET OF ROYALTIES	2005	2004	200
CRUDE OIL AND NGLS (bbl/d)			
North America	191,751	180,011	152,44
North Sea	68,487	64,598	56,92
Offshore West Africa	22,293	11,221	10,31
	282,531	255,830	219,68
NATURAL GAS (mmcf/d)			
North America	1,125	1,048	97
North Sea	18	50	4
Offshore West Africa	4	7	
	1,147	1,105	1,03
TOTAL BARREL OF OIL EQUIVALENT (boe/d)	473,742	440,022	391,36

Daily production and per barrel statistics are presented throughout this MD&A on a "before royalty" or "gross" basis. Production net of royalties is presented for information purposes only.

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 crude oil and NGLs, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil.

Record levels of total crude oil and natural gas production averaged 552,960 boe/d for the year ended December 31, 2005, an increase of 8% or 39,125 boe/d from 513,835 boe/d for the year ended December 31, 2004 (2003 - 458,814 boe/d). The increase in production year over year was due to organic growth from the Company's extensive North America capital expenditure program and the commencement of production from the Baobab Field offshore Cote d'Ivoire in 2005, as well as the full year impact of accretive acquisitions completed in 2004.

Total record crude oil and NGLs production for the year ended December 31, 2005 increased 11% to 313,168 bbl/d from 282,489 bbl/d for the year ended December 31, 2004 (2003 - 242,392 bbl/d). Crude oil and NGLs production for 2005 was in line with the Company's guidance of 308,000 to 316,000 bbl/d.

Natural gas production continues to represent the Company's largest product offering. Natural gas production for the year ended December 31, 2005 increased 4% or 51 mmcf/d to average 1,439 mmcf/d compared to 1,388 mmcf/d for the year ended December 31, 2004 (2003 - 1,299 mmcf/d). Growth in natural gas production in Western Canada was negatively affected by the early arrival of spring breakup and weather related delays due to unusually wet conditions as well as an overall increase in industry activity. The market for the necessary oilfield services and material has become increasingly competitive, resulting in drilling, completion, tie-in and maintenance delays. Natural gas production for 2005 was in line with the Company's guidance of 1,436 to 1,448 mmcf/d.

The Company expects annual production levels in 2006 to average 1,468 to 1,551 mmcf/d of natural gas and 335,000 to 373,000 bbl/d of crude oil and NGLs. First quarter 2006 production is expected to be between 1,426 and 1,475 mmcf/d of natural gas and 306,000 to 334,000 bbl/d of crude oil and NGLs.

NORTH AMERICA

North America crude oil and NGLs production for the year ended December 31, 2005 increased 7% or 15,444 bbl/d to average 221,669 bbl/d, up from 206,225 bbl/d for the year ended December 31, 2004 (2003 - 174,895 bbl/d). The increase in crude oil and NGLs production was mainly due to the timing of Primrose production cycles and the positive results of the Pelican Lake waterflood project.

North America natural gas production for the year ended December 31, 2005 increased 6% or 86 mmcf/d to average 1,416 mmcf/d, up from 1,330 mmcf/d in 2004 (2003 - 1,245 mmcf/d). Natural gas production increased as a result of organic growth and the full year impact of accretive property acquisitions in 2004, but was negatively impacted by the early arrival of spring breakup and weather related delays due to unusually wet conditions during the summer months. In addition to weather related factors, production growth was also negatively impacted by the increased demand for oilfield services and materials, which caused delays in the timing of production being brought on stream.

NORTH SEA

North Sea crude oil production for the year ended December 31, 2005 was 68,593 bbl/d, an increase of 6% from 64,706 bbl/d for 2004 (2003 - 56,869 bbl/d). Production levels were in line with expectations, reflecting anticipated curtailments at the Lyell Field and the Columba B and E Terraces, continued restrictions at Murchison Field due to third party natural gas export facilities and production declines at the satellite Playfair Field.

Natural gas production in the North Sea for the year ended December 31, 2005 decreased 62% to average 19 mmcf/d, down from 50 mmcf/d for the year ended December 31, 2004 (2003 - 46 mmcf/d). The decrease in natural gas production was due to the commencement of the natural gas reinjection program in the Banff Field in the Central North Sea late in 2004. The natural gas reinjection project is expected to result in an overall increase in the reservoir recovery, but resulted in reductions in natural gas production in 2005.

OFFSHORE WEST AFRICA

Offshore West Africa crude oil production for the year ended December 31, 2005 increased 98% to 22,906 bbl/d from 11,558 bbl/d for the year ended December 31, 2004 (2003 - 10,628 bbl/d). The production increase was primarily due to commencement of production from the 57.61% owned and operated Baobab Field in August 2005, as well as increased production from additional infill wells drilled in East Espoir.

ROYALTIES	2005	2004	2003
CRUDE OIL AND NGLS ($/bbl) (1)			
North America	$ 5.37	$ 4.21	$ 3.79
North Sea	$ 0.10	$ 0.08	$(0.03)
Offshore West Africa	$ 1.62	$ 1.43	$ 1.08
Company average	$ 3.97	$ 3.16	$ 2.77
NATURAL GAS ($/mcf) (1)			
North America	$ 1.78	$ 1.40	$ 1.38
North Sea	$ --	$ --	$ --
Offshore West Africa	$ 0.16	$ 0.15	$ 0.13
Company average	$ 1.75	$ 1.35	$ 1.32
COMPANY AVERAGE ($/boe) (1)	$ 6.82	$ 5.37	$ 5.20
PERCENTAGE OF REVENUE (2)			
Crude oil and NGLs	8%	8%	9%
Natural gas	20%	21%	21%
Boe	14%	14%	15%

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

NORTH AMERICA

North America crude oil and NGLs royalties per bbl for the year ended December 31, 2005 increased from 2004 primarily due to higher benchmark crude oil prices, offset by wider heavy crude oil differentials and a strengthening Canadian dollar. Royalty rates are expected to increase in the future as a result of the Primrose South Field payout expected to occur late in 2006 or early 2007.

Natural gas royalties increased from 2004 due to higher benchmark natural gas prices, offset by a stronger Canadian dollar and adjustments to royalty rates related to prior years.

NORTH SEA

North Sea government royalties on crude oil were eliminated effective January 1, 2003. The remaining North Sea royalty represents a gross overriding royalty on the Ninian Field. In 2003, the Company received a refund of royalties previously provided.

OFFSHORE WEST AFRICA

Offshore West Africa production is governed by the terms of Production Sharing Contracts ("PSCs"). Under the PSCs, revenues are divided into cost recovery revenue and profit revenue. Cost recovery revenue allows the Company to recover its capital and operating costs and the costs carried by the Company on behalf of the Government State Oil Company. Profit revenue is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. These revenues are reported as sales revenue. The Government's share of profit revenue attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the PSCs. Based on current projections, the Espoir Field and the Baobab Field are expected to reach payout in 2007, which will increase royalty rates and current income taxes in accordance with the PSCs.

PRODUCTION EXPENSE	2005	2004	2003
CRUDE OIL AND NGLS ($/bbl) (1)			
North America	$ 10.49	$ 8.94	$ 9.14
North Sea	$ 14.94	$ 14.03	$ 14.07
Offshore West Africa	$ 6.50	$ 7.59	$ 8.68
Company average	$ 11.17	$ 10.05	$ 10.28
NATURAL GAS ($/mcf) (1)			
North America	$ 0.71	$ 0.62	$ 0.57
North Sea	$ 2.44	$ 2.07	$ 1.33
Offshore West Africa	$ 1.05	$ 1.33	$ 1.39
Company average	$ 0.73	$ 0.67	$ 0.60
COMPANY AVERAGE ($/boe) (1)	$ 8.21	$ 7.35	$ 7.15

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

The Company continues to experience increasing production expense in 2006, reflecting industry cost pressures in all of its operating areas.

NORTH AMERICA

North America crude oil and NGLs production expense per bbl for the year ended December 31, 2005 increased by 17% from 2004. The increase was primarily due to higher industry wide service costs, higher fuel related expenses, and a larger portion of the Company's crude oil volumes being comprised of higher cost thermal crude oil in 2005 versus 2004, offset by the positive impact of higher volumes relative to fixed costs.

North America natural gas production expense per mcf for the year ended December 31, 2005 increased from the comparable periods in 2004. The increase from 2004 was due to the service and commodity cost pressures previously noted, offset by the positive impact of higher volumes relative to fixed costs.

NORTH SEA

North Sea crude oil production expense varied on a per barrel basis from 2004 primarily due to the timing of maintenance work, the changes in production volumes on a relatively fixed cost base, the timing of liftings from various fields and the impact of production being diverted from the Kyle Field to the Banff floating production storage and offtake vessel ("FPSO").

OFFSHORE WEST AFRICA

Offshore West Africa crude oil production expenses are largely fixed in nature and fluctuated on a per barrel basis from 2004 due to changes in volumes. Production expenses for the year ended December 31, 2005 compared to 2004 were primarily impacted by the commencement of production from the Baobab Field in August 2005.

MIDSTREAM

($ millions)	2005	2004	2003
Revenue	$ 77	$ 68	$ 61
Production expense	24	20	15
Midstream cash flow	53	48	46
Depreciation	8	7	7
Segment earnings before taxes	$ 45	$ 41	$ 39

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.

Earnings and cash flow attributable to midstream assets have increased marginally from 2004 primarily due to increased heavy crude oil throughput volumes and increased revenue from the Company's cogeneration plant.

DEPLETION, DEPRECIATION AND AMORTIZATION(1)

($ millions, except per boe amounts) (2)	2005	2004	2003
North America	$ 1,595	$ 1,444	$ 1,209
North Sea	306	265	252
Offshore West Africa	104	53	41
Expense	$ 2,005	$ 1,762	$ 1,502
$/boe	$ 10.02	$ 9.37	$ 8.96

(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") for the year ended December 31, 2005 increased in total and on a boe basis from 2004. The increase in DD&A was due to higher finding and development costs associated with natural gas exploration in North America, the fair value allocation of the acquisition costs associated with acquisitions completed late in 2004, future abandonment costs associated with the acquisition of additional properties in the North Sea, higher estimated future costs to develop the Company's proved undeveloped reserves in the North Sea and the commencement of production from the Baobab Field in August 2005.

ASSET RETIREMENT OBLIGATION ACCRETION

($ millions, except per boe amounts) (1)	2005	2004	2003
North America	$ 34	$ 28	$ 26
North Sea	34	22	36
Offshore West Africa	1	1	--

Expense	$ 69	$ 51	$ 62
$/boe	$ 0.34	$ 0.27	$ 0.37

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

Accretion expense is the increase in the carrying amount of the asset retirement obligations due to the passage of time. Asset retirement obligation accretion expense for North America increased $6 million or 21% from 2004, primarily due to increased activity in the conventional drilling program and increased requirements under provincial reclamation legislation. Accretion expense for the North Sea increased $12 million or 55% from 2004, largely due to the impact of additional retirement obligations related to property acquisitions completed late in 2004.

ADMINISTRATION EXPENSE

($ millions, except per boe amounts) (2)	2005	2004(1)	2003
Net expense	$ 151	$ 125	$ 87
$/boe	$ 0.75	$ 0.66	$ 0.52

(1) Restated to conform to current year presentation.
(2) Amounts expressed on a per unit basis are based on sales volumes.

Net administration expense for the year ended December 31, 2005 increased in total and on a boe basis from the year ended December 31, 2004 primarily due to higher staffing levels associated with the Company's expanding asset base and costs associated with the Company's Share Bonus Plan.

The Share Bonus Plan incorporates employee share ownership in the Company while reducing the granting of stock options and the dilution of current Shareholders. Under the plan, cash bonuses awarded based on Company and employee performance are subsequently used by a trustee to acquire common shares of the Company. The common shares vest to the employee over a three-year period provided the employee does not leave the employment of the Company. If the employee leaves the employment of the Company, the unvested common shares are forfeited under the terms of the plan. For the year ended December 31, 2005, the Company recognized $17 million of compensation expense under the Share Bonus Plan (December 31, 2004 - $10 million; 2003 - $nil).

STOCK-BASED COMPENSATION

($ millions)	2005	2004	2003
Stock-based compensation expense	$ 723	$ 249	$ 200

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 $723 million ($481 million after tax) stock-based compensation expense for the year ended December 31, 2005 in connection with the 125% appreciation in the Company's share price (December 31, 2005 - C$57.63; December 31, 2004 - C$25.63; December 31, 2003 - C$16.34; December 31, 2002 - C$11.70). 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 quarterly 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 (2005 - $101 million; 2004 - $21 million; 2003 - $10 million). The stock-based compensation liability reflects the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on December 31, 2005. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the year ended December 31, 2005, the Company paid $227 million for stock options surrendered for cash settlement (December 31, 2004 - $80 million; 2003 - $31 million).

INTEREST EXPENSE

($ millions, except per boe amounts and interest rates)(1)	2005	2004	2003
Interest expense	$ 149	$ 189	$ 201
$/boe	$ 0.74	$ 1.01	$ 1.20
Average effective interest rate	5.6%	5.2%	5.8%

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

Net interest expense decreased on a total and boe basis for the year ended December 31, 2005 from 2004 primarily due to the capitalization of construction period interest related to the Horizon Project in 2005 of $72 million (2004 and 2003 - $nil). Pre-capitalization interest increased from 2004 mainly due to higher interest rates and carrying charges, offset by decreased average debt levels and the impact of the strengthening Canadian dollar, which decreased interest expense attributable to the Company's US dollar denominated debt securities.

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 used for trading or speculative purposes. Changes in fair value of derivative financial instruments designated as hedges are not recognized in net earnings until such time as the corresponding gains or losses on the related hedged items are also recognized. Changes in fair value of derivative financial instruments not designated as hedges are recognized in the consolidated balance sheets each period with the offset reflected in risk management activities in the statements of earnings.

The Company formally documents all 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 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. Gains or losses on these contracts are included in risk management activities.

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 amount on which the payments are based. Gains or losses on interest rate swap contracts designated as hedges are included in interest expense. Gains or losses on non-designated interest rate contracts are included in risk management activities.

Cross currency swap agreements 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. Gains or losses on cross currency swap contracts designated as hedges are included in interest expense.

Gains or losses on the termination of derivative financial instruments that have been designated as hedges are deferred under other assets or liabilities on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged transaction 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 net earnings. Gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in net earnings immediately.

($ millions)	2005	2004	2003
Realized loss (gain)			
Crude oil and NGLs financial instruments	$ 753	$ 501	$ 95
Natural gas financial instruments	283	5	88
Interest rate swaps	(9)	(32)	(35)
	$ 1,027	$ 474	$ 148
Unrealized loss (gain)			
Crude oil and NGLs financial instruments	$ 847	$ (47)	$ --
Natural gas financial instruments	77	--	--
Interest rate swaps	1	7	--
	$ 925	$ (40)	$ --
Total	$ 1,952	$ 434	$ 148

The realized loss from crude oil and NGLs and natural gas financial instruments decreased the Company's average realized prices as follows:

	2005	2004	2003
Crude oil and NGLs ($/bbl)(1)	$ 6.68	$ 4.85	$ 1.07
Natural gas ($/mcf)(1)	$ 0.54	$ 0.01	$ 0.19

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

The realized gain on non-designated interest rate swaps would have decreased the Company's reported interest expense as follows:

($ millions, except interest rates)	2005	2004	2003
Interest expense as reported	$ 149	$ 189	$ 201
Less: realized risk management gain	(9)	(32)	(35)
	$ 140	$ 157	$ 166
Average effective interest rate	5.2%	4.4%	4.8%

As effective as commodity hedges are against reference commodity prices, a substantial portion of the derivative financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The Company is required to mark-to-market these non-designated hedges based on prevailing forward commodity prices in effect at the end of each reporting period. Accordingly, unrealized risk management expense reflects, at the balance sheet date, the implied price differentials for the non-designated hedges for future years. Due to the dramatic increase in crude oil and natural gas forward pricing in 2005, the Company recorded a $925 million ($607 million after tax) unrealized loss on its risk management activities for the year ended December 31, 2005 (2004 - a $40 million gain or $27 million after tax; 2003 - $nil).

The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at December 31, 2005.

In addition to the risk management liability recognized on the balance sheet at December 31, 2005, the net unrecognized liability related to the fair value of derivative financial instruments designated as hedges was $990 million (December 31, 2004 - net unrecognized asset of $33 million).

Details relating to outstanding derivative financial instruments at December 31, 2005 are disclosed in note 10 to the Company's audited annual consolidated financial statements as at December 31, 2005.

FOREIGN EXCHANGE

($ millions)	2005	2004	2003
Realized foreign exchange (gain) loss	$ (29)	$ 3	$ 8
Unrealized foreign exchange gain	(103)	(94)	(343)
Total	$(132)	$ (91)	$ (335)

The Company's results are affected by 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 lower 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 will result in higher revenue from the sale of the Company's production. Production expenses are also subject to fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar related to North Sea operations. 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.

In 2005, the majority of the realized foreign exchange gain was the result of the repayment of the Company's US dollar preferred securities. In addition, net foreign exchange gains were realized on foreign exchange rate fluctuations on working capital items denominated in US dollars or UK pounds sterling. The unrealized foreign exchange gain is related to the fluctuation of the Canadian dollar in relation to the US dollar with respect to the US dollar debt and working capital denominated in US dollars or UK pounds sterling. The Canadian dollar ended the year at US$0.8577 compared to US$0.8308 at December 31, 2004 (2003 - US$0.7738).

In order to mitigate a portion of the volatility associated with fluctuations in exchange rates, the Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment in Shareholders' equity in the consolidated balance sheets.

TAXES

($ millions, except income tax rates)	2005	2004	2003
Taxes other than income tax			
Current	$ 203	$ 210	$ 116
Deferred	(9)	(45)	(9)
Total	$ 194	$ 165	$ 107
Current income tax			
North America - Current income tax	$ 82	$ 89	$ 43
North America - Large Corporations Tax	16	11	16
North Sea	155	2	23
Offshore West Africa	32	13	10
Other	1	1	--
Total	$ 286	$ 116	$ 92
Future income tax	$ 353	$ 474	$ 338
Effective income tax rate	37.8%	29.6%	23.5%

Taxes other than income tax includes current and deferred petroleum revenue tax ("PRT") and Canadian provincial capital taxes and surcharges. 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 generated by partnerships, with the related income taxes payable in a subsequent year. North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary upon the nature and amount of capital expenditures incurred in Canada.

The North Sea current income tax expense for 2005 increased from 2004 due mainly to higher realized product prices, increased sales volumes and the deductibility in 2004 of the cost of assets acquired in the UK. In December 2005, the UK government announced plans to double the supplementary charge on profits from UK North Sea crude oil and natural gas production to 20%. If enacted, the increased North Sea supplementary charge would increase the Company's income tax rate in the North Sea from 40% to 50%. The supplementary charge excludes any deduction for financing costs. A charge has not been reflected in 2005 net earnings as the proposed change has not been substantively enacted. If enacted in 2006, the Company anticipates that this rate change will result in a charge to future income taxes in the amount of $111 million.

During 2005, the province of British Columbia enacted legislation to reduce its corporate income tax rate by 1.5% effective July 1, 2005. As a result, the North America future income tax liability was reduced by $19 million. In 2004, the North America future tax liability was reduced by $66 million as a result of a reduction in the Alberta corporate income tax rate from 12.5% to 11.5%. In 2003, the Federal Government enacted legislation to reduce the corporate income tax rate on income from resource activities over a five-year period starting January 1, 2003, bringing the resource industry in line with the general corporate income tax rate. As part of the corporate income tax rate reduction, the legislation also provides for the phased elimination of the existing 25% resource allowance and the introduction of a deduction for actual provincial and other crown royalties paid.

The following table shows the effect of non-recurring benefits on income taxes:

($ millions, except income tax rates)	2005	2004	2003
Income tax as reported			
Current income tax	$ 286	$ 116	$ 92
Future income tax expense	353	474	338
	639	590	430
Provincial corporate tax rate reductions	19	66	31
Federal corporate tax rate reductions	--	--	247
Total	$ 658	$ 656	$ 708
Expected effective income tax rate before non-recurring benefits	39.0%	32.9%	38.6%

The effective income tax rate for 2005 increased over 2004 due to the effects of the phased elimination of the resource allowance and the phased deductibility of crown royalties. It is anticipated that in 2006, based on budgeted prices and the current availability of tax pools, the Company is expected to be cash taxable in Canada in the amount of $110 million to $170 million.

CAPITAL EXPENDITURES (1)

($ millions)	2005	2004	2003

Expenditures on property, plant and equipment			
Net property acquisitions (2)	$ (320)	$ 1,835	$ 336
Land acquisition and retention	254	120	154
Seismic evaluations	132	89	77
Well drilling, completion and equipping	2,000	1,394	1,194
Pipeline and production facilities	1,295	821	522
Total net reserve replacement expenditures	3,361	4,259	2,283
Horizon Project:			
Phase 1 construction costs	1,329	--	--
Capitalized interest and other	170	291	152
Total Horizon Project	1,499	291	152
Midstream	4	16	11
Abandonments (3)	46	32	40
Head office	22	35	20
Total net capital expenditures	$ 4,932	$ 4,633	$ 2,506
By segment			
North America	$ 2,530	$ 3,355	$ 1,769
North Sea	387	608	338
Offshore West Africa	439	295	176
Other	5	1	--
Horizon Project	1,499	291	152
Midstream	4	16	11
Abandonments (3)	46	32	40
Head office	22	35	20
Total	$ 4,932	$ 4,633	$ 2,506

(1) The net capital expenditures do not include non-cash property, plant and equipment additions or disposals.
(2) Includes Business Combinations. The 2004 comparative figure includes $26 million in non-cash consideration.
(3) Abandonments represent expenditures to settle asset retirement obligations 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 focuses its activities in core regions where it can dominate the land base and infrastructure. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for the year ended December 31, 2005 were $4,932 million compared to $4,633 million for the year ended December 31, 2004 (2003 - $2,506 million). During 2005, the Company continued to make significant progress on its larger, future-growth projects, most notably the Horizon Project, while maintaining its focus on existing assets. The Company drilled a total of 1,882 net wells in 2005 consisting of 890 natural gas wells, 627 crude oil wells, 248 stratigraphic test and service wells, and 117 wells that were dry. This compared to 1,449 net wells drilled in 2004 (2003 - 1,793 net wells). The Company achieved an overall success rate of 93%, excluding stratigraphic test and service wells (2004 and 2003 - 91%).

NORTH AMERICA

North America accounted for approximately 83% of the total capital expenditures for the year ended December 31, 2005 compared to approximately 80% in 2004 (2003 - 79%).

During 2005, the Company drilled 975 net wells targeting natural gas, including 228 wells in Northeast British Columbia, 238 wells in the Northern Plains region, 166 wells in Northwest Alberta, and 343 wells in the Southern Plains region. The Company also drilled 642 net wells targeting crude oil during 2005. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 360 heavy crude oil wells, 84 Pelican Lake crude oil wells, 109 thermal crude oil wells, and 7 light crude oil wells were drilled. Another 82 light crude oil wells were drilled during the year in the Company's other regions.

As part of the development of the Company's heavy crude oil resources, the Company is continuing with its Primrose thermal projects, which includes the Primrose North expansion project and drilling additional wells in the Primrose South project to augment existing production. The Primrose North expansion was substantially completed in 2005 with total capital expenditures of approximately $300 million incurred. Initial steaming commenced in November 2005 and first crude oil production began in January 2006.

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 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 expects construction to begin in 2007, with initial steaming scheduled for January 2009.

Development at Pelican Lake continued on track in 2005, with 84 wells being drilled and production increasing from approximately 18,000 bbl/d to approximately 28,000 bbl/d over the course of the year. The waterflood conversion project is on schedule with production response exceeding expectations. The Company plans to enhance the waterflood process through utilization of Polymer Flood technology. A Polymer Flood pilot has been in operation since May 2005 with positive results. The drilling of 150 horizontal wells is planned for 2006.

During 2005, the Company sold a large portion of its overriding royalty interests on various producing properties throughout Western Canada and Ontario that were considered non-core to its operations, for proceeds of approximately $345 million, after giving effect to anticipated adjustments.

Above average temperatures have continued into 2006. Accordingly, the Company is leveraging its deep drilling inventory and optimizing drilling plans to adjust for road bans and/or site access issues. Despite these challenges the Company still expects to complete the majority of its winter drilling program. However, the risk remains for an early spring breakup which could significantly delay tie-ins of many of these new wells. In 2006, the Company's overall drilling activity in North America is expected to be comprised of approximately 1,139 net natural gas wells and 697 net crude oil wells excluding stratigraphic test/service wells.

HORIZON PROJECT

On February 9, 2005 the Board of Directors of the Company unanimously approved the Company to proceed with Phase 1 of the Horizon Project.

The Horizon Project has continued on schedule and on budget. Specifically, as at December 31, 2005:

- Phase 1 Horizon Project construction was 19% complete;
- The detailed engineering work was on schedule, with 3-D engineering models progressing as planned;
- The Company awarded $3.8 billion of contracts and purchase orders, with a further $600 million in various stages of the tender process; and
- Approximately 1,700 people were on site and functional.

Major activities for 2006 will include:

- Substantial completion of detailed engineering;
- Completion and setting of main piperack modules;
- Receiving and erecting of critical equipment;
- Beginning construction of ore preparation plant; and
- Substantial completion of foundations in each area.

First production of light, sweet Synthetic Crude Oil from Phase 1 construction is targeted to commence in the second half of 2008. The Horizon Project is in the early stages of construction.

NORTH SEA

The Company continued in 2005 with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During 2005, 14 net wells were drilled, consisting of 12 net crude oil wells, 1 net dry well and 1 net service well, with an additional 2.9 net wells drilling at quarter-end.

In anticipation of the 2005 program of infill drilling, workovers, and third party business on the T and B Blocks, the Company completed a major refurbishment of the Tiffany platform drilling rig, which is facilitating a two-well program targeting unswept areas of the field. The first of these two wells was drilled and completed late in 2005.

Production from the Kyle Field was diverted to the Banff FPSO during 2005. Under the terms of an early termination agreement, the existing Kyle FPSO was released in September 2005. The consolidation of these production facilities is expected to result in lower combined operating costs from these fields and may ultimately extend field lives for both fields.

OFFSHORE WEST AFRICA

Offshore West Africa capital expenditures include the development of the 57.61% owned and operated Baobab Field, which commenced production on August 9, 2005 at approximately 30,000 bbl/d net to the Company. Upon completion of drilling additional wells in 2006, production levels are expected to achieve approximately 35,000 bbl/d net to the Company.

In East Espoir, two of the four infill wells scheduled for drilling were completed during 2005, with the remainder expected to be completed in 2006. The drilling of these wells was a result of additional testing and evaluation that revealed a larger quantity of crude oil in place, based upon reservoir studies and production history to date. These new producer wells will effectively exploit this additional potential and could increase the recoverable resources and production. The West Espoir drilling tower, which will facilitate development drilling of the reservoir, is on site and was installed in late 2005. This project is progressing on time and on budget with first crude oil expected in 2006, increasing to approximately 13,000 boe/d once fully developed.

The Company purchased a 100% operator interest in the Olowi PSC offshore Gabon in October 2005 and received approval of its development plan for this acquisition subsequent to year end. Development plans include a FPSO handling input from two or three shallow-water producing platforms. Development is expected to begin late in 2006, with first oil expected late in 2008 at a rate of approximately 20,000 bbl/d.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	2005	2004	2003
Working capital deficit (1)	$ 1,774	$ 652	$ 505
Long-term debt	$ 3,321	$ 3,538	$ 2,748
Shareholders' equity			
Share capital	$ 2,442	$ 2,408	$ 2,353
Retained earnings	5,804	4,922	3,650
Foreign currency translation adjustment	(9)	(6)	3
Total	$ 8,237	$ 7,324	$ 6,006
Debt to cash flow (2)	0.7x	1.0x	0.9x
Debt to EBITDA (3)	0.6x	0.9x	0.8x
Debt to book capitalization (4)	28.7%	33.8%	32.8%
Debt to market capitalization	9.7%	21.4%	25.1%
After tax return on average common shareholders' equity (5)	14.3%	21.4%	25.6%
After tax return on average capital employed (6)	10.4%	15.3%	17.1%

(1) Calculated as current assets less current liabilities.
(2) Calculated as current and long-term debt; divided by cash flow from operations for the year.
(3) Calculated as current and long-term debt; divided by earnings before interest, taxes, depreciation, depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activities for the year.
(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.
(5) Calculated as net earnings for the year as a percentage of average common shareholders' equity for the period.
(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 current and long-term debt for the year.

The Company's capital resources at December 31, 2005 consist primarily of cash flow from operations and available credit facilities. 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 dependent upon these factors, 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 five and ten year financial plans, the Company's existing credit facilities and the Company's ability to raise new debt, will be sufficient to sustain its operations and support its growth strategy.

At December 31, 2005 the Company had undrawn bank lines of credit of $3,285 million. These credit lines are supported by credit facilities, which if not extended, mature in 2008, 2009 and 2010.

At December 31, 2005, the Company's working capital deficit was $1,774 million and included the current portion of other long-term liabilities of $1,471 million, comprised of stock-based compensation of $629 million and the mark-to-market valuation of non-designated risk management financial derivative instruments of $842 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 financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at December 31, 2005.

The Company is committed to maintaining a strong financial position. In 2005, strong operational results and high commodity prices resulted in debt to book capitalization levels of 28.7%. The Company believes it has the necessary financial capacity to complete the

Horizon Project while at the same time not compromising delivery of 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. Existing proved development projects, which have largely been funded prior to December 31, 2005, such as Baobab, Primrose North and West Espoir should provide identified growth in production volumes in 2006 through 2008, and are expected to generate incremental free cash flows during this period.

In January 2005, the Board of Directors authorized the expansion of the Company's commodity hedging program to reduce the risk of volatility in commodity price markets and to underpin the Company's cash flow for its capital expenditures program through the Horizon Project construction period. This expanded 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 through the use of derivative financial instruments. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. As a result, approximately 75% of budgeted 2006 crude oil volumes have been hedged through the use of collars. Approximately 60% of budgeted 2006 natural gas volumes have similarly been hedged through the use of collars. In addition, for 2007, put options have been acquired on 200,000 bbl/d at an average floor price of US$47.50 and a further 100,000 bbl/d at an average floor price of US$28.00. The Company has not hedged any production volumes beyond 2007. The Company continues to evaluate the need for further hedging in 2007 and beyond, given continuing capital requirements for Horizon and other capital projects.

LONG-TERM DEBT

Long-term debt at December 31, 2005 amounted to $3,321 million. The debt to EBITDA ratio decreased to 0.6x and the debt to book capitalization decreased to 28.7% compared to a debt to EBITDA ratio of 0.9x and a debt to book capitalization of 33.8% in 2004. These ratios are currently below the Company's guidelines for balance sheet management of debt to EBITDA of 1.5x to 2.0x and debt to book capitalization of 35% to 45%.

OPERATING FACILITIES

As at December 31, 2005 the Company had in place unsecured syndicated bank credit facilities of $3,425 million, comprised of:

- a $100 million operating demand facility;
- a two-tranche revolving credit and term loan facility of $1,825 million; and
- a 5-year revolving and term loan facility of $1,500 million.

The first $1,000 million tranche of the $1,825 million facility is fully revolving for a period of three years to June 2008. The second tranche of $825 million is fully revolving for a period of five years to June 2010. Both tranches are extendible annually for one-year periods at the mutual agreement of the Company and the lenders. If not extended, the full amount of the outstanding principal would be repayable at the end of year two following the initiation of the term period. The $1,500 million revolving credit and term loan facility has a five-year term, with three, one-year extension provisions. If the facility is not extended, the amount outstanding would be repayable in December 2009. These facilities provide that the borrowings may be made by way of operating advances, prime loans, bankers' acceptances, US base rate loans or US dollar LIBOR advances, which bear interest at the bank's prime rates or at money market rates plus applicable margins.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2005, was 5.44% (2004 - 3.47%).

The Company also has an unsecured (pound)15 million demand overdraft credit facility for the Company's North Sea operations. At December 31, 2005 there were no amounts drawn on this facility.

In addition to the outstanding debt, as at December 31, 2005 letters of credit aggregating $24 million have been issued.

MEDIUM-TERM NOTES

In May 2005, the Company issued $400 million of debt securities maturing June 2015, bearing interest at 4.95%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

In May 2004, the Company repaid the $125 million 6.85% unsecured debentures due May 2004, which were issued under a previous medium-term note program.

In January 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. After issuing these securities, the Company has $1.6 billion remaining on its $2 billion shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

SENIOR UNSECURED NOTES

In December 2005, the Company repaid the US$125 million 7.69% senior unsecured notes. The 6.42% senior unsecured notes were repaid in May 2004.

The adjustable rate senior unsecured notes bear interest at 6.54% and have annual principal repayments of US$31 million commencing in May 2007, through May 2009.

PREFERRED SECURITIES

In September 2005, the Company redeemed the US$80 million 8.30% preferred securities due May 25, 2011 for cash consideration of US$91 million, including an early repayment premium of US$11 million as required under the Note Purchase Agreement.

US DOLLAR DEBT SECURITIES

In June 2005, the Company filed a short form shelf prospectus that allows for the issue of up to US$2 billion of debt securities in the United States until July 2007. If issued, these securities will bear interest as determined at the date of issuance.

In December 2004, the Company issued US$350 million of debt securities maturing December 2014, bearing interest at 4.90% and US$350 million of debt securities maturing February 2035, bearing interest at 5.85%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. The Company has entered into interest rate swap contracts to convert the fixed rate interest coupon into a floating interest rate on the securities due December 2014.

The ratings of the Company's debt securities and its relationships with principal banks are important to the Company as it continues to expand and grow. Hence, it is the Company's management intention to maintain a strong balance sheet and financial position. The Company's debt securities are rated "Baa1" with a stable outlook by Moody's Investor Services Inc., "BBB+" by Standard & Poors Corporation ("S&P") and "BBB(high)" with a stable trend by Dominion Bond Rating Services Limited. S&P assigns a rating outlook to the Company and not to the individual debt instruments. S&P has assigned a negative outlook to the Company.

SHARE CAPITAL

Shareholders of the Company approved a subdivision or share split of its issued and outstanding common shares on a two-for-one basis at the Company's Annual and Special Meeting held on May 5, 2005. As at December 31, 2005, there were 536,348,000 common shares outstanding. As at February 21, 2006, the Company had 537,156,000 common shares outstanding.

In January 2005, the Company renewed its Normal Course Issuer Bid allowing it to purchase up to 26,818,012 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2005 and ending January 23, 2006. As at December 31, 2005, the Company had purchased 850,000 common shares at an average price of $53.29 per common share for a total cost of $45 million.

In January 2006, the Company announced the renewal of its Normal Course Issuer

Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase up to 26,852,545 common shares or 5% of the outstanding common shares of the Company on the date of the announcement, during the 12-month period beginning January 24, 2006 and ending January 23, 2007. As at February 21, 2006, the Company had not purchased any additional shares under the Normal Course Issuer Bid.

In February 2005, the Board of Directors approved an increase in the annual dividend paid by the Company to $0.225 per common share. In May 2005, the Board of Directors approved an increase in the annual dividend paid by the Company to $0.24 per common share. In February 2004, the Board of Directors increased the annual dividend paid by the Company to $0.20 per common share, up from the previous level of $0.15 per common share.

In February 2006, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.30 per common share for 2006. The increase represents a 27% increase from the prior year, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. This is the sixth consecutive year in which the Company has paid dividends and the fifth consecutive year of an increase in the distribution paid to its Shareholders.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various contractual arrangements and commitments that will have an impact on the Company's future operations. These contractual obligations and commitments primarily relate to debt repayments, operating leases relating to office space and offshore production and storage vessels, and firm commitments for gathering, processing and transmission services, as well as expenditures relating to asset retirement obligations. The Company has not entered into any contracts that would require consolidation under CICA Accounting Handbook, AcG-15, Consolidation of Variable Interest Entities. The following table summarizes the Company's commitments as at December 31, 2005:

($ millions)	2006	2007	2008	2009	2010	Ther
Product transportation and pipeline (1)	$ 195	$ 133	$ 148	$ 94	$ 85	$
Offshore equipment operating lease	$ 51	$ 51	$ 52	$ 51	$ 51	$
Offshore drilling	$ 132	$ 100	$ 35	$ --	$ --	$
Asset retirement obligations (2)	$ 82	$ 4	$ 4	$ 4	$ 7	$
Long-term debt (3)	$ --	$ 161	$ 36	$ 36	$ --	$
Other (4)	$ 61	$ 62	$ 21	$ 29	$ 23	$

(1) During the year, the Company entered into a 25 year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, annual toll payments before operating costs will be approximately $35 million.
(2) Represents management's estimate of the future payments to settle asset retirement obligations related to resource properties, facilities, production platforms and gathering systems, based on current legislation

and industry operating practices.
(3) No debt repayments are reflected for the bank credit facilities due to the extendable nature of the facilities.
(4) Consists of future expenditures related primarily to office lease, electricity and crude oil processing.

The Board of Directors has approved the construction costs for Phase 1 of the Horizon Project, which are budgeted to be $6.8 billion, including a contingency fund of $700 million, with $1.3 billion incurred in 2005, $2.6 billion to be incurred in 2006 and $2.9 billion to be incurred in 2007 and 2008.

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The Company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

RESERVES

For the year ended December 31, 2005, 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 and probable crude oil, natural gas liquids ("NGL") and natural gas reserves (1) and prepare Evaluation Reports on these reserves. Sproule evaluated the Company's North America conventional assets and Ryder Scott evaluated its 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 United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. There are two principal differences between the two standards. The first is the additional 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 Company has disclosed 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 this Annual Report. The Company has elected to provide the net present value (2) of these same conventional proved reserves as well as the 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 most recent Annual Information Form.

Reserves and net present values presented for years prior to 2003 were evaluated in accordance with the standards of National Policy 2-B which has now been replaced by NI 51-101. The stated reserves were reasonably evaluated as economically productive using year-end costs and prices escalated at appropriate rates throughout the productive life of the properties.

For the year ended December 31, 2005, 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 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 probable crude oil, NGL and natural gas reserves.

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, NGL and natural gas reserves as well as the Company's quantity of oil sands mining reserves.

Additional reserve disclosure is contained in the supplementary oil and gas information of this Annual Report and the Company's most recent Annual Information Form.

(1) Conventional crude oil, NGL and natural gas includes all of the Company's light and medium, heavy, and thermal crude oil, natural gas, coal bed methane and natural gas liquid 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 with the exception of Offshore West Africa where all abandonment liabilities have been included.

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. These inherent risks include, but are not limited to, the following items:

- Economic risk of finding and producing 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 and depletion rates.

- Pricing risk of marketing reserves at an acceptable price given current market conditions.

- 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.

- 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 at commercially acceptable terms.

- Foreign exchange risk due to fluctuating exchange rates, as the majority of sales are based in US dollars.

- Environmental impact risk associated with exploration and development activities.

- Risk of catastrophic loss due to fire, explosion or acts of nature.

- Other risks associated with changing governmental policies, social instability and other political, economic or diplomatic developments in the Company's international operations.

The Company uses a variety of means to help 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 regions with high working interests and by assuming operatorship of all key facilities. Product mix is diversified, ranging from the production of natural gas to the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Sales of crude oil and natural gas are aimed at various markets to ensure that undue exposure to any one market does not exist. 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 risks by entering into sales contracts and financial derivatives with only highly rated entities and financial institutions. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions. Refer to the "Risk management activities" section of this MD&A. In addition, 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.

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 most recent Annual Information Form.

ENVIRONMENT

The Company continues to employ an Environmental Management Plan (the "Plan") to ensure the welfare of its employees, the communities in which it operates, and the environment as a whole. Environmental protection is of fundamental importance and is undertaken in accordance with guiding principles approved by the Company's Board of Directors. A detailed copy of the Company's Plan is presented to, and reviewed by, the Board of Directors annually. The Plan is updated quarterly at the Directors' meetings.

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

- An annual internal environmental compliance audit and inspection program of the Company's 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; and
- A program to replace the majority of fresh water for steaming with brackish water.

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 greenhouse natural gas emissions 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.

In 2005, the Company's capital expenditures included $46 million for abandonment expenditures, an increase from $32 million in 2004 (2003 - $40 million).

Estimated asset retirement obligation, undiscontinued ($ millions)	2005	2004
North America	$ 2,050	$ 1,770
North Sea	1,185	1,265
Offshore West Africa	90	25
	3,325	3,060
North Sea PRT recovery	(370)	(600)
	$ 2,955	$ 2,460

The estimate of the future site restoration liability is based on estimates of future costs to abandon and restore the wells, production facilities and offshore production platforms. There are numerous factors that affect these costs including such things as the number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs and technology in accordance with present legislation and industry operating practice. The future abandonment costs to be incurred by the Company in the North Sea will result in an estimated recovery of PRT of $370 million (2004 - $600 million, 2003 - $330 million), as abandonment costs are an allowable deduction in determining PRT and may be carried back to reclaim PRT previously paid. The PRT recovery reduces the net abandonment liability of the Company to $2,955 million (2004 - $2,460 million, 2003 - $1,950 million). The North Sea PRT recovery has decreased substantially from 2004 primarily due to improved economics related to the various fields, including a higher pricing environment and stronger Canadian dollar at December 31, 2005. Under these economic conditions, end of field losses at Tiffany previously assumed to be available for relief against PRT due from other fields is significantly reduced. 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.

KYOTO PROTOCOL

In December 2002, the Canadian Federal Government ratified the Kyoto Protocol ("Kyoto"). The Company continues to work with the Federal and Provincial governments on the regulatory framework for greenhouse gases for larger emitters. The framework under development would see harmonized regulation between the two levels of government. Both levels of government have indicated that existing legislation will be amended in 2006 to create further requirements for reporting emissions, facility-based emission intensity targets and regulatory compliance. Compliance with emission intensity targets is expected for 2008, which is the first year of the compliance period for the Kyoto Protocol.

The Company will continue to develop strategies that will enable it to deal with the risks and opportunities associated with new climate change policies. In addition, the Company will work with relevant parties to ensure that new policies encourage innovation, energy efficiency, targeted research and development while not impacting Canada's competitive position.

Due to the high degree of cost uncertainty when the Federal Government ratified Kyoto, maximum per tonne cost assurances were agreed with large emitters for 2008 - 2012. Beyond 2012 investment concerns were addressed by the Federal Government as outlined in eight principles that would guide its negotiations and policies for this later stage.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the Company's financial position and operations. 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 profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country. Under Canadian GAAP, 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 higher 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 probable crude oil and natural gas reserves. In 2005, 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, future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. 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 reserve estimate 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 OBLIGATION

Under CICA Handbook Section 3110, Asset Retirement Obligations ("ARO"), the Company is required to recognize a liability for the future retirement obligations associated with the Company's 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 based on experience.

The estimated fair values of asset retirement obligations 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 asset retirement obligations 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 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 of 6.8%. In subsequent periods, the asset retirement obligation 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 asset retirement obligation, timing of cash flows to settle the obligation and future inflation rates could result in gains or losses on the final settlement of the asset retirement obligations.

An ARO is not recognized for assets with an indeterminate useful life (e.g. pipeline assets) because an amount cannot be reasonably estimated. An ARO for these assets will be recorded in the first period in which the lives of these assets are determinable.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various instruments to manage its commodity price and foreign currency exposures on revenue, and interest rate exposures on US dollar denominated debt. These derivative and financial instruments are not used for trading or speculative purposes.

On January 1, 2004, the Company prospectively adopted the Canadian Institute of Chartered Accountants' ("CICA") Accounting Guideline ("AcG") 13, "Hedging Relationships" and Emerging Issues Committee ("EIC") 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial instruments". Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded on the consolidated balance sheet as either an asset or liability with changes in fair value recognized in net earnings. The estimate of fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indications. The cash settlement amount of the risk management financial derivative instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their mark-to-market value at December 31, 2005.

PURCHASE PRICE ALLOCATIONS

The costs of corporate and asset acquisitions are allocated to the 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 amount 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 made 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 future price forecasts amongst 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

Based on their evaluation as of December 31, 2005, the Company's President and the Chief Financial Officer concluded, pursuant to Canadian Multilateral Instrument 52-109 Part 2.1, that the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings is recorded, processed, summarized and reported within the time periods that meet the regulatory requirements. In addition, as of December 31, 2005, there were no changes in the Company's internal controls over financial reporting that occurred during 2005 that have materially affected, or are reasonably likely to materially affect its internal controls over financial reporting. The Company will continue to periodically evaluate its disclosure controls and procedures and internal controls over financial reporting and will make any modifications from time to time as deemed necessary.

NEW ACCOUNTING STANDARDS

In January 2005, the CICA issued four new standards relating to the recognition, measurement and disclosure of financial instruments.

- Section 3855 - "Financial Instruments - Recognition and Measurement" prescribes when a financial asset, financial liability, or non-financial derivative is to be recognized on the balance sheet as well as its measurement amount. This Section also specifies how financial instruments gains and losses are to be presented. Transitional provisions for this Section vary based on the type of financial instruments under consideration.

- Section 3865 - "Hedges" expands on existing AcG 13 - "Hedging Relationships", and Section 1650 "Foreign Currency Translation", by specifying how hedge accounting is to be applied and what disclosures are necessary when it is applied. Retroactive application of this Section is not permitted.

- Section 1530 - "Comprehensive Income" introduces new standards for reporting and disclosure of comprehensive income. 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 those resulting from investments by owners and distributions to owners. Financial statements of prior periods are required to be restated only for non-financial instrument items.

- Section 3251 - "Equity" replaces Section 3250 "Surplus" and establishes standards for the presentation of equity and changes in equity during a reporting period. Financial statements of prior periods are required to be restated only for non-financial instrument items. For all other items, comparative financial statements presented are not restated, but an adjustment to the opening balance of accumulated other comprehensive income may be required.

The Company plans to adopt these new standards effective January 1, 2007. The effect on the Company's consolidated financial statements cannot be reasonably determined at this time as the financial derivatives outstanding at December 31, 2006 and their related fair values are not known.

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 high shareholder returns. Annual budgets are developed, scrutinized throughout the year and changed if necessary in the context of 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 2006 to average 1,468 mmcf/d to 1,551 mmcf/d of natural gas and 335,000 bbl/d to 373,000 bbl/d of crude oil and NGLs.

The budgeted capital expenditures in 2006 are currently expected to be as follows: Drilling will comprise both deep and conventional targets, with new production growth coming from the Company's Northeast British Columbia and Northwest Alberta areas.

($ millions)	2006 Budget
North America natural gas	$ 1,741
North America crude oil and NGLs	1,097
North Sea	733
Offshore West Africa	187
Property acquisitions, dispositions and midstream	63
	3,821
Horizon Project Phase 1 Construction	2,561
Capitalized interest and other items	222
Horizon Project Phases 2/3 engineering	128
Canadian Natural Upgrader engineering	30
Total	$ 6,762

NORTH AMERICA NATURAL GAS

The 2006 North American natural gas program will be as follows:

(number of wells)	2006 Budget
Northeast British Columbia	262
Northwest Alberta	147
Northern Plains	251
Southern Plains	479

Total	1,139

NORTH AMERICA CRUDE OIL AND NGLS

The 2006 North America crude oil drilling program is highlighted by continued development of Primrose North thermal production and another strong conventional heavy program, as follows:

(number of wells)	2006 Budget
Conventional heavy crude oil	344
Thermal heavy crude oil	92
Light crude oil	111
Pelican Lake crude oil	150
Total	697

The Company continues the disciplined development of its heavy crude oil resources. Conventional heavy crude oil drilling is expected to increase, reflecting favourable crude oil prices and new opportunities identified in the property acquisitions made during 2004. Due to the nature of heavy crude oil production patterns, where production volumes ramp up during the first months of production, much of the production resulting from the expanded drill program will not be realized until late 2007.

In 2006, the Company expects to continue its Primrose thermal crude oil expansion plans. Activity in 2006 will be focused on the Primrose South expansion. Production from this project is subject to the cycling of steam injection and crude oil production and is expected to remain at similar levels to the 2005 production. The waterflood conversion project is on schedule with production response exceeding expectations. The Polymer Flood pilot project has yielded positive results to date and will continue in 2006.

THE 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 expected to commence in the second half of 2008 at 110,000 bbl/d of 34(degree) API light, sweet synthetic crude oil ("SCO"). 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.

Construction costs for Phase 1 of the Horizon Project are estimated at $6.8 billion including a contingency reserve of $700 million, with $1.3 billion incurred in 2005, $2.6 billion to be incurred in 2006 and $2.9 billion to be incurred in 2007 and 2008.

Extensive front end design and the high degree of project definition have enabled the Company to obtain approximately 68% of Phase 1 costs on a fixed price basis. The high degree of up front project engineering and pre-planning is expected to reduce the risks associated with scope changes.

NORTH SEA

The capital budget in 2006 for the North Sea is $733 million and includes the drilling of approximately 12 net platform wells on Ninian, Murchison and

Tiffany. The Company will also conduct a mobile drilling program for which 6 subsea producer wells will be drilled at Columba E, Lyell, Toni and Thelma. Average crude oil production is expected to increase from 2005 production levels; however, natural gas volumes are expected to be flat as natural gas production at the Banff Field is diverted to reinjection.

OFFSHORE WEST AFRICA

In 2006, the capital budget for Offshore West Africa is set at $187 million, of which the Company anticipates $79 million to be spent on completing infill drilling at East Espoir and developing the West Espoir Field. West Espoir development is expected to yield first oil by mid-2006 at approximately 13,000 boe/d. Two additional wells will be completed at Baobab in 2006, allowing production to ramp to approximately 35,000 bbl/d net to the Company. $32 million will be expended on development of the Olowi Field offshore Gabon in 2006, with first oil expected late in 2008.

SENSITIVITY ANALYSIS (1)

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 2005. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant.

	CASH FLOW FROM OPERATIONS ($ millions)	CASH FLOW FROM OPERATIONS ($/share, basic)	NET EARNINGS ($ millions)	N ($/s
Price changes				
Crude oil - WTI US$1.00/bbl (2)				
Excluding financial derivatives	$ 113	$ 0.21	$ 79	
Including financial derivatives	$ 60	$ 0.11	$ 40	
Natural gas - AECO C$0.10/mcf (2)				
Excluding financial derivatives	$ 38	$ 0.07	$ 24	
Including financial derivatives	$ 14	$ 0.03	$ 8	
Volume changes				
Crude oil - 10,000 bbl/d	$ 104	$ 0.19	$ 53	
Natural gas - 10 mmcf/d	$ 32	$ 0.06	$ 17	
Foreign currency rate change				
$0.01 change in C$ in relation to US$ (2)	$ 82-84	$ 0.15-0.16	$ 32-33	
Interest rate change - 1%	$ 7	$ 0.01	$ 7	

(1) The sensitivities are calculated based on 2005 fourth quarter results excluding mark-to-market gains (losses) on risk management activities.
(2) For details of financial instruments in place, refer to note 10 to the Company's audited annual consolidated financial statements as at December 31, 2005.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES (1)

	Q1	Q2	Q3	Q4	2005	2004	
Crude oil and NGLs (bbl/d)							
North America	209,125	215,693	231,260	230,263	221,669	206,225	1
North Sea	71,139	62,884	73,543	66,798	68,593	64,706	
Offshore West Africa	7,539	10,487	29,921	43,207	22,906	11,558	
Total	287,803	289,064	334,724	340,268	313,168	282,489	2
Natural gas (mmcf/d)							
North America	1,430	1,434	1,400	1,402	1,416	1,330	
North Sea	23	17	18	15	19	50	
Offshore West Africa	2	3	5	6	4	8	
Total	1,455	1,454	1,423	1,423	1,439	1,388	
Barrels of oil equivalent (boe/d)							
North America	447,446	454,602	464,607	463,869	457,695	427,936	3
North Sea	74,956	65,751	76,545	69,361	71,651	73,093	
Offshore West Africa	7,914	11,027	30,759	44,275	23,614	12,806	
Total	530,316	531,380	571,911	577,505	552,960	513,835	4

(1) The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. For production where revenue has not yet been recognized, the related crude oil inventory volumes, by segment, were as follows at December 31, 2005:

(bbls)	
North America, related to Corsicana pipeline line fill	4
North Sea, related to timing of liftings	7
Offshore West Africa, related to timing of liftings, net of government entitlement to profit oil	4
	1,6

At December 31, 2004, variances between production volumes and liftings were not significant.

PER UNIT RESULTS (1)

	Q1	Q2	Q3	Q4	2005	2004
Crude oil and NGLs ($/bbl)						
Sales price (2)	$ 39.81	$ 42.51	$ 57.35	$ 46.38	$ 46.86	$ 37.99
Royalties	3.39	3.33	5.11	3.89	3.97	3.16

Production expense	11.30	11.66	11.48	10.33	11.17	10.05
Netback	$ 25.12	$ 27.52	$ 40.76	$ 32.16	$ 31.72	$ 24.78
Natural gas ($/mcf)						
Sales price (2)	$ 6.68	$ 7.33	$ 8.61	$ 11.67	$ 8.57	$ 6.50
Royalties	1.30	1.48	1.93	2.30	1.75	1.35
Production expense	0.69	0.71	0.76	0.76	0.73	0.67
Netback	$ 4.69	$ 5.14	$ 5.92	$ 8.61	$ 6.09	$ 4.48
Barrels of oil equivalent ($/boe)						
Sales price (2)	$ 39.94	$ 43.05	$ 54.87	$ 56.08	$ 48.77	$ 38.45
Royalties	5.42	5.85	7.84	8.01	6.82	5.37
Production expense	8.04	8.29	8.56	7.93	8.21	7.35
Netback	$ 26.48	$ 28.91	$ 38.47	$ 40.14	$ 33.74	$ 25.73

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

NETBACK ANALYSIS

($/boe) (1)	2005	2004
Sales price (2)	$ 48.77	$ 38.45
Royalties	6.82	5.37
Production expense (3)	8.21	7.35
Netback	33.74	25.73
Midstream contribution (3)	(0.26)	(0.26)
Administration (4)	0.75	0.66
Interest, net	0.74	1.01
Realized risk management activities loss	5.13	2.52
Realized foreign exchange (gain) loss	(0.15)	0.02
Taxes other than income tax - current	1.01	1.12
Current income tax - North America	0.41	0.47
Current income tax - Large Corporations Tax	0.08	0.05
Current income tax - North Sea	0.77	0.01
Current income tax - Offshore West Africa	0.17	0.07
Current income tax - other	0.01	0.01
Cash flow	$ 25.08	$ 20.05

(1) Amounts expressed on a per unit basis are based on sales volume.
(2) Including transportation costs and excluding risk management activities.
(3) Excluding inter-segment eliminations.
(4) Restated to conform to current year presentation.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2
TSX - C$					
Trading volume (thousands)	169,018	155,274	160,121	153,579	

Share price ($/share)				
High	$ 37.38	$ 46.98	$ 60.00	$ 62.00
Low	$ 24.28	$ 30.54	$ 45.52	$ 43.55
Close	$ 34.18	$ 44.40	$ 52.50	$ 57.63
Market capitalization at December 31 ($ millions)				
Shares outstanding (thousands)				
NYSE - US$				
Trading volume (thousands)	48,333	68,743	66,802	67,676
Share price ($/share)				
High	$ 30.37	$ 38.03	$ 50.73	$ 54.05
Low	$ 19.74	$ 24.49	$ 36.87	$ 36.65
Close	$ 28.41	$ 36.38	$ 45.19	$ 49.62
Market capitalization at December 31 ($ millions)				
Shares outstanding (thousands)				

(1) Restated to reflect two-for-one share split in May 2005.

TEN-YEAR REVIEW

Years ended December 31	2005	2004	2003	2002	2001	2000	
FINANCIAL INFORMATION							
(C$ millions, except per share amounts)							
Net earnings	1,050	1,405	1,403	539	639	758	
Per share - basic (1)	$ 1.96	$ 2.62	$ 2.62	$ 1.06	$ 1.32	$ 1.62	$
Cash flow from operations (2)	5,021	3,769	3,160	2,254	1,290	1,884	
Per share - basic (1)	$ 9.36	$ 7.03	$ 5.88	$ 4.41	$ 3.96	$ 4.04	$
Capital expenditures, net of dispositions (including business combinations)	4,932	4,633	2,506	4,069	1,885	2,823	1
Balance Sheet information							
Working capital (deficiency) surplus	(1,774)	(652)	(505)	(14)	(6)	(77)	
Property, plant and equipment, net	19,694	17,064	13,714	12,934	8,766	7,439	4
Total assets	21,852	18,372	14,643	13,793	9,290	8,051	4
Long-term debt	3,321	3,538	2,748	4,200	2,788	2,573	2
Shareholders' equity	8,237	7,324	6,006	4,754	3,928	3,297	1
SHARE INFORMATION							
Common shares outstanding (thousands)	536,348	536,361	534,926	535,104	484,804	489,116	445
Weighted average shares outstanding (thousands)	536,650	536,223	536,940	511,532	485,200	466,804	415
Dividends declared per common share	$ 0.24	$ 0.20	$ 0.15	$ 0.13	$ 0.10	$ -	$
Trading statistics (1)							
TSX-C$							
Trading volume (thousands)	637,992	606,024	590,702	619,316	534,976	567,412	430
Share Price ($/share)							
High	$ 62.00	$ 27.58	$ 16.81	$ 13.64	$ 13.09	$ 14.05	$
Low	$ 24.28	$ 15.96	$ 11.30	$ 9.40	$ 8.98	$ 7.45	$
Close	$ 57.63	$ 25.63	$ 16.34	$ 11.70	$ 9.58	$ 10.38	$

NYSE-US$							
Trading volume (thousands)	251,554	125,468	46,916	31,864	20,764	3,172	
Share Price ($/share)							
High	$ 54.05	$ 22.37	$ 12.85	$ 8.72	$ 8.63	$ 9.46	$
Low	$ 19.74	$ 11.94	$ 7.32	$ 5.89	$ 5.70	$ 6.19	$
Close	$ 49.62	$ 21.39	$ 12.61	$ 7.42	$ 6.10	$ 6.88	$
RATIOS							
Debt to cash flow (3)	0.7x	1.0x	0.9x	1.9x	1.5x	1.4x	
Debt to book capitalization (3)	28.7%	33.8%	32.8%	47.1%	41.7%	44.0%	5
Return on average common shareholders' equity, after tax (3)	14.3%	21.4%	25.6%	13.0%	17.7%	28.8%	1
Debt to EBITDA (3)	0.6x	0.9x	0.8x	1.7x	1.4x	1.2x	
Daily production before royalties per ten thousand common shares (boe/d)	10.3	9.6	8.5	8.2	7.4	6.6	
Conventional proved and probable reserves per common share (boe) (4)	4.8	4.3	4.0	3.3	3.1	2.9	
Net asset value per common share (1)(5)	60.44	33.13	23.35	19.57	16.88	20.54	1

(1) Restated to reflect two-for-one share splits in May 2004 and May 2005.
(2) Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. The Company evaluates its performance based on earnings and cash flow. Cash flow from operations may not be comparable to similar measures used by other companies.
(3) Refer to the MD&A, page 62, "Liquidity and Capital Resources", for the definitions of these items.
(4) Based upon constant dollar Company gross reserves (before royalties), using year-end common shares outstanding.
(5) Based upon 10% discounted, forecast price pre-tax proved and probable net present values as reported in the Company's AIF for conventional reserves, with $250/acre added for core undeveloped land in 2005 and $75/acre for all years prior, less long-term debt and existing asset liabilities and adjusted for working capital. See reserves disclosures on pages 40 to 44.

Years ended December 31	2005	2004	2003	2002	2001	2000	1999
OPERATING INFORMATION							
Conventional crude oil and NGLs (mmbbl)							
Company gross proved reserves (before royalties)							
North America	785	695	672	665	644	643	554
North Sea	290	303	222	203	83	102	-
Offshore West Africa	148	125	106	94	61	36	-
	1,223	1,123	1,000	962	788	781	554
Company gross proved and probable reserves (before royalties)							
North America	1,154	992	977	742	740	731	640
North Sea	417	415	317	277	106	134	-

Offshore West Africa	230	214	187	162	111	46	-
	1,801	1,621	1,481	1,181	957	911	640
Conventional natural gas (bcf)							
Company gross proved reserves (before royalties)							
North America	3,378	3,202	3,006	3,048	2,566	2,360	2,183
North Sea	29	27	62	71	94	91	-
Offshore West Africa	83	81	86	90	69	65	-
	3,490	3,310	3,154	3,209	2,729	2,516	2,183
Company gross proved and probable reserves (before royalties)							
North America	4,372	4,100	3,611	3,450	2,915	2,762	2,547
North Sea	69	57	101	89	118	114	-
Offshore West Africa	127	102	111	120	96	84	-
	4,568	4,259	3,823	3,659	3,129	2,960	2,547
Total proved reserves (before royalties) (mmboe)	1,804	1,674	1,526	1,497	1,243	1,200	918
Total proved and probable reserves (before royalties) (mmboe)	2,562	2,330	2,118	1,791	1,479	1,404	1,065
Oil sands, mining (mmbbl)							
Gross proved and probable reserves (before royalties)							
Bitumen	3,430	-	-	-	-	-	-
Synthetic crude oil *	2,878	-	-	-	-	-	-
Daily production (before royalties)							
Crude oil and NGLs (mbbl/d)							
North America	222	206	175	169	167	155	87
North Sea	68	65	57	39	36	17	-
Offshore West Africa	23	12	10	7	3	2	-
	313	283	242	215	206	174	87
Natural gas (mmcf/d)							
North America	1,416	1,330	1,245	1,204	906	793	721
North Sea	19	50	46	27	12	1	-
Offshore West Africa	4	8	8	1	-	-	-
	1,439	1,388	1,299	1,232	918	794	721
Total production (before royalties)(mboe/d)	553	514	459	421	359	306	207
Product pricing							
Average crude oil and NGLs price ($/bbl)	46.86	37.99	32.66	31.22	23.45	31.89	22.26
Average natural gas price ($/mcf)	8.57	6.50	6.21	3.77	5.45	4.92	2.52

* SCO reserves are based upon upgrading of the bitumen reserves. The reserves shown for bitumen and SCO are not additive.

ADDITIONAL DISCLOSURE

DISCLOSURE CONTROLS AND PROCEDURES

As of the end of the registrant's fiscal year ended December 31, 2005, 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 principal executive officer and principal financial officer. Based upon the evaluation, Canadian Natural's principle 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 the 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.

During the fiscal year ended December 31, 2005, there were no changes in the registrant's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the registrant'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 New York Stock Exchange Listed Company Manual.

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, to ensure that Canadian Natural's business is conducted in a consistently legal and ethical manner. Each director and all employees, including each member of senior management and more specifically the principal executive officers, 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. No waivers and no implicit waivers to the Code of Ethics in whole or in part have been asked for or granted to any director, senior officer or employee as of the date of this Annual Report.

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, 2005 and December 31, 2004, for professional services rendered by PwC for the audit of its 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 $1,200,235 and $1,100,548, respectively.

AUDIT-RELATED FEES: The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ending December 31, 2005 and December 31, 2004, for audit-related services by PwC consisting of debt covenant compliance, Crown Royalty Statements, and services related to internal control reviews and assistance with Sarbanes-Oxley Section 404 relating to internal control reporting requirements were, $266,923 and $183,663 respectively. 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, 2005 and December 31, 2004, 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 2005 were $39,331 and $39,330, respectively. 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, 2005 and December 31, 2004 for other services were $7,290 and $nil respectively. The fees for other services paid in 2005 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 2005.

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 65 of Canadian Natural's Management's Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2005, filed herewith, under the caption "Commitments and Off Balance Sheet Arrangements".

CONTRACTUAL OBLIGATIONS

In the normal course of business, the Company has entered into various contractual arrangements and commitments that will have an impact on the Company's future operations. These contractual obligations and commitments primarily relate to debt repayments, operating leases relating to office space and offshore production and storage vessels, and firm commitments for gathering, processing and transmission services, as well as expenditures relating to asset retirement obligations. The Company has not entered into any contracts that would require consolidation under CICA Accounting Handbook, AcG-15, Consolidation of Variable Interest Entities. The following table summarizes the Company's commitments as at December 31, 2005:

($ MILLIONS)	TOTAL	2006	2007	2008	2009
Product transportation and pipline	1,766	195	133	148	94
Offshore equipment and leasing	436	51	51	52	51
Offshore drilling	267	132	100	35	-
Asset Retirement Obligation(1)	3,325	82	4	4	4
Long-term debt(2)	3,199	-	161	36	36
Other(3)	204	61	62	21	29
TOTAL	9,197	521	511	296	214

(1) Represents management's estimate of the future payments to settle asset retirement obligations related to resource properties, facilities, production platforms and pipelines, based on current legislation and industry operating practices.

(2) No debt repayments are reflected for the bank credit facilities due to the extendable nature of the facilities. As at December 31, 2005 there was $122 million outstanding owed under the bank credit facilities.

(3) Consists of future expenditures related primarily to office lease, electricity and crude oil processing.

Total construction costs for the three phases of the Horizon Project development are expected to be approximately $10.8 billion. The Board of Directors has approved the construction costs for Phase 1 of the Horizon Project, which are expected to be $6.8 billion, including a contingency fund of $700 million, with $1.3 billion incurred in 2005, $2.6 billion forecast to be incurred in 2006 and $2.9 billion forecast to be incurred in 2007 and 2008 combined.

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The Company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

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, 2005, 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

The Company 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 29th day of March, 2006.

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 NUMBER	DESCRIPTION
1.	Supplementary Oil & Gas Information for the fiscal year ended December 31, 2005.
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 Rule 13(a)-14(b) and 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 Rule 13(a)-14(b) and 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 Gilbert Laustsen Jung Associates Ltd., independent petroleum engineering consultants.