CANADIAN NATURAL RESOURCES LTD
Form 40-F/A
April 30, 2010

United States
Securities and Exchange Commission

Washington, D.C. 20549

FORM 40-F/A
(AMENDMENT N0. 1)

[ ] 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, 2009 Commission File Number: 333-12138

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

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

1311
(Primary Standard Industrial Classification Code Numbers)

Not Applicable
(I.R.S. Employer Identification Number (if applicable))

2500, 855-2nd Street S.W., Calgary, Alberta, Canada, T2P 4J8
Telephone: (403) 517-7345
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System, 111-Eighth Avenue, New York, New York 10011
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

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

Title of Each Class:	Name of each exchange on which registered:

Common Shares, no par value New York Stock Exchange

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

Title of Each Class: None

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

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

[X] Annual information form [ ] 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.

542,327,240 Common Shares outstanding as of December 31, 2009

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 [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (s.232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes [ ] No [ ]

EXPLANATORY NOTE

This Amendment to the Registrant's Annual Report on Form 40-F filed on April 1, 2010 for the fiscal year ended December 31, 2009 (the "Original Filing"), is being filed for the purpose of amending Canadian Natural's Annual Information Form for the year ended December 31, 2009, in order to make a correction in a table on page 41 in the Probable Forecast Price Case coluumn for the year 2017 and a summation correction in that table in the Thereafter 2020 row.

Other than as expressly set forth above, this Amendment does not, and does not purport to, update or restate the information in the Original Filing or reflect any events that have occurred after the Original Filing was filed. The filing of this Amendment shall not be deemed an admission that the Original Filing, when made, included any known, untrue statement of material fact or knowingly omitted to state a material fact necessary to make a statement not misleading.

Principal Document

The following document has been filed as part of this Amendment to the 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, 2009.

AMENDED

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2009

MARCH 25, 2010

TABLE OF CONTENTS

DEFINITIONS AND ABBREVIATIONS

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

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

“ARO” means Asset Retirement Obligation

“bbl” or “barrel” means 34.972 Imperial gallons or 42 US gallons

“bcf” means one billion cubic feet

“bbl/d” means barrels per day

“boe” means barrel of oil equivalent

“boe/d” means barrel of oil equivalent per day

“CO2” means carbon dioxide

“CO2e” means carbon dioxide equivalents

“Canadian GAAP” means Generally Accepted Accounting Principles in Canada

“Canadian Natural Resources Limited”, “Canadian Natural”, “Company”, or “Corporation” means Canadian Natura Resources Limited and includes, where applicable, reference to subsidiaries of and partnership interests held by Canadian Natural Resources Limited and its subsidiaries

“CBM” means Coal Bed Methane

“crude oil, NGLs and natural gas” includes all of the Company’s crude oil, synthetic crude oil, bitumen, coal bed methane, NGLs and natural gas reserves "development well" means a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive

"dry well" means an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well

"exploratory well" means a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir

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

"GHG" means Greenhouse Gas

"gross acres" means the total number of acres in which the Company has a working interest

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

"Horizon" means Horizon Oil Sands

"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

“net asset value” means the discounted pre-tax value of forecast price proved and probable crude oil and natural gas reserves (net of future development costs and associated material well abandonment costs) plus the value of core undeveloped land, less net debt.

“net wells” refers to gross wells multiplied by the percentage working interest therein owned by the Company

“NYSE” means New York Stock Exchange

“productive well” means an exploratory, development or extension well that is not dry

“PRT” means Petroleum Revenue Tax

“SAGD” means Steam-Assisted Gravity Drainage

“SCO” means Synthetic Crude Oil

“SEC” means United States Securities and Exchange Commission

“TSX” means Toronto Stock Exchange

“undeveloped acreage” refers to lands on which wells have not been drilled or completed to a point that would permit the production of economic quantities of crude oil and natural gas regardless of whether such acreage contains proved reserves.

“UK” means the United Kingdom

“US” means United States

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

"WTI" means West Texas Intermediate

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to the Company in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could" "intend", "may", "potential", "predict", "should "project", "forecast", "goal", "guidance", "outlook", "effort" "seeks", "schedule" or expressions of a similar nature suggesti outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, production volumes, royalties, operating costs, capital expenditures, and other guidance provided in the 2010 outlook section and throughout this document and the documents incorporated herein by reference constitute forward looking statements. Disclosure of plans relating to existing and future developments including but not limited to Horizon, Primrose East, Pelican Lake, Olowi Field (Offshore Gabon), and the Kirby Thermal Oil Sands Project also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts and is reviewed and revised throughout the year if necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

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

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

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

Special Note Regarding Currency, Production and Reserves

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

For the year ended December 31, 2009, the Company retained qualified independent reserves evaluators, Sproule Associates Limited ("Sproule"), and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved, as well as probable crude oil, synthetic crude oil, bitumen, coal bed methane, NGLs and natural gas reserves and prepare Evaluation Reports on these reserves. Sproule evaluated and reviewed all of the Company's crude oil, bitumen, natural gas, coal bed methane and NGLs reserves. GLJ evaluated all of the synthetic crude oil reserves related to the Company's oil sands mine. The Company has been granted an exemption from certain provisions of National Instrument 51-101 – "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute SEC requirements under Regulations S-K and S-X for certain disclosures required under NI 51-101. On December 31, 2008, the SEC released its final rules for the modernization of oil and gas reporting ("Final Rule"). The material changes include the ability to include oil sands mining as an oil and gas activity, ability to use reliable technology to establish undeveloped reserves, the optional ability to report probable reserves, the requirement to track undeveloped locations, as well as the directive to use 12-month average prices and current costs. These resulting changes are more in line with NI 51-101 however there are material differences to the type of volumes disclosed and the basis from which the volumes are determined. NI 51-101 requires gross reserves and future net revenue under forecast pricing and costs, however, the SEC, as discussed, requires disclosure of net reserves, after royalties, under 12-month average prices and current costs. The difference between the reported numbers under the two disclosure standards can be material.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with Sproule and GLJ as to the Company's reserves.

The Company annually discloses proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs as mandated by the SEC in the supplementary crude oil and natural gas information section of the Company's Annual Report and in its annual Form 40-F filing with the SEC.

Special Note Regarding Non-GAAP Financial Measures

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

RISK FACTORS

Volatility of Crude Oil and Natural Gas Prices

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

Approximately 26% of the Company's 2009 production on a boe basis was primary and thermal heavy crude oil. The market prices for heavy crude oil differ from the established market indices for light and medium grades of crude oil due principally to the quality difference and the mix of product obtained in the refining process referred to as the "quality differential". As a result, the price received for heavy crude oil is generally lower than the price for medium and light crude oil, and the production costs associated with heavy crude oil may be higher than for lighter grades. Future quality differentials are uncertain and a significant increase in the heavy crude oil differentials could have a material adverse effect on the Company's financial condition.

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

Need to Replace Reserves

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

Uncertainty of Reserve Estimates

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

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

Completion Risk

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

Competition in Energy Industry

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

Access to Sources of Liquidity

The ability of the Company to fund current and future capital projects and carry out our business plan is dependent on our ability to raise capital in a timely manner under favourable terms and conditions.

Environmental Risks

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

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

The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation, particularly in North America and the North Sea. Existing and expected legislation and regulations may require the Company to address and mitigate the effect of its activities on the environment. Increasingly stringent laws and regulations, including any new regulations the US may impose to limit purchases of crude oil in favour of less energy intensive sources, may have a material adverse effect on the Company’s financial condition.

Greenhouse Gas and Other Air Emissions

There are a number of unresolved issues in relation to Canadian federal and provincial GHG regulatory requirements. Key among them is the form of regulation, an appropriate common facility emissions threshold, availability and duration of compliance mechanisms and resolution of federal/provincial harmonization agreements. The Company continues to pursue GHG emissions reduction initiatives including solution gas conservation, compressor optimization to improve fuel gas efficiency, CO2 capture and sequestration in oil sands tailings, CO2 capture and storage in association with enhanced oil recovery and participation in an industry initiative to promote an integrated CO2 capture and storage network.

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

In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in the near term to address industrial GHG emissions, as part of the national GHG reduction target. The Federal Government has also outlined national and sectoral reduction targets for several categories of air pollutants.

In Alberta, GHG regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO2e annually. Two of the Company’s facilities, the Primrose/Wolf Lake in-situ heavy crude oil facilities and the Hays sour natural gas plant, fall under the regulations. The British Columbia carbon tax is currently being assessed at $15/tonne of CO2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $20/tonne on July 1, 2010, and to $30/tonne by July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia has also announced that certain upstream oil and gas facilities will be included in a regional cap and trade system beginning in 2012. It is estimated that six facilities in BC will be included under the cap and trade system, based on a proposed 25 kilotonne of CO2e threshold. Saskatchewan is expected to release GHG regulation in 2010 that may require the North Tangleflags in-situ heavy oil facility to meet a reduction target for its GHG emissions intensity. In the UK, GHG regulations have been in effect since 2005. During Phase 1 (2005 – 2007) of the UK National Allocation Plan, the Company operated below its CO2 allocation. For Phase 2 (2008 – 2012) the Company’s CO2 allocation has been decreased below the Company’s estimated current operations emissions. The compliance costs to the Company relating to the above regulations for 2009 are approximately $26 million.

Legislation to regulate GHGs in the United States through a cap and trade system is currently before the US Congress, although there is no certainty as to the form or stringency of the final legislation. In the absence of legislation, the US Environmental Protection Agency (EPA) is authorized under the Clean Air Act to regulate GHGs, although EPA action would be subject to legal and political challenges. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the US. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oils with higher emissions intensity.

The additional requirements of enacted or proposed GHG legislation on the Company’s operations will increase capital expenditures and production expense, especially those related to Horizon and the Company’s other existing and planned large oil sands projects. Depending on the legislation enacted, this may have an adverse effect on the Company's financial condition.

Hedging Activities

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

Operational Risk

Exploring for, producing and transporting petroleum substances involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. These activities are subject to a number of hazards which may result in fires, explosions, spills, blow-outs or other unexpected or dangerous conditions causing personal injury, property damage, environmental damage and interruption of operations. The Horizon operations are subject to loss of production, potential shutdowns and increased production costs due to the integration of the various component parts, as well as severe winter weather conditions.

Foreign Investments

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

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

Other Business Risks

Other business risks relate to the dependency on third party operators for some of the Company's assets, timing and success of integrating the business and operations of acquired companies, credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, risk of litigation, regulatory issues, and risk of increases in government taxes and changes to the royalty regime. The majority of the Company's assets are held in one or more corporate subsidiaries or partnerships. The results of operations and ability to service indebtedness, including debt securities, are dependent upon the results of operations of these subsidiaries and partnerships and, in the case of subsidiaries, the payment of funds to the Company in the form of loans, dividends or other means utilized for the payment of funds to the Company. In the event of the liquidation of any corporate 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 Canada and the UK review the operations of the Company's world-wide interests and report on a regular basis to the senior management of the Company, which in turn reports on environmental matters directly to the Health, Safety and Environmental Committee of the Board of Directors.

The Company regularly meets with and submits to inspections by the various governments in the regions where the Company operates. The Company believes that it meets all existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. Since these requirements apply to all operators in the crude oil and natural gas industry, it is not anticipated that the Company's competitive position within the industry will be adversely affected by changes in applicable legislation. The Company has internal procedures designed to ensure that the environmental aspects of new acquisitions and developments are taken into account prior to proceeding. The Company's environmental management plan and operating guidelines focus on minimizing the environmental impact of field operations while meeting regulatory requirements and corporate standards. The Company's proactive program includes: an internal environmental compliance audit and inspection program of its operating facilities; a suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an effective surface reclamation program; a due diligence program related to groundwater monitoring; an active program related to preventing spills and reclaiming spill sites; a solution gas conservation program; a program to replace the majority of fresh water for steaming with brackish water; water management programs to improve efficiency of use, recycle rates and water storage; environmental planning for all projects to assess environmental impacts and to implement avoidance, and mitigation programs; reporting for environmental liabilities; a program to optimize efficiencies at the Company's operating facilities; continued evaluation of new technologies to reduce environmental impacts; development of a tailings management plan; and CO2 reduction programs including the injection of CO2 into tailings and for use in enhanced oil recovery. The Company has also established operating standards in the following areas: exercising care with respect to all waste produced through effective waste management plans; using water-based, environmentally friendly drilling muds whenever possible; and minimizing produced water volumes offshore through cost-effective measures. Canadian Natural participates in both the Canadian federal and provincial regulated GHG emissions reporting programs. The Company continues to quantify annual GHG emissions for internal reporting purposes. The Company has participated in the Canadian Association of Petroleum Producers ("CAPP") Stewardship Program since 2000. Canadian Natural continues to invest in proven and new technologies and in improved operating strategies to help us achieve the Company's overall GHG management goals.

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

The Company continues to focus on reducing GHG emissions through improved efficiency, and on trading mechanisms to ensure compliance with requirements now in effect. Canadian Natural is committed to managing air emissions through an integrated corporate approach which considers opportunities to reduce both air pollutants and GHG emissions. Air quality programs continue to be an essential part of the Company's environmental work plan and are operated within all regulatory standards and guidelines. The Company strategy for managing GHG emissions is based on six core principles: improving energy conservation and efficiency; reducing emission intensity; developing and adopting innovative technology and supporting associated research and development; trading capacity, both domestically and globally; offsetting emissions; and considering life cycle costs of emission reductions in decision-making about project development.

The Company continues to implement flaring, venting and fuel and solution gas conservation programs. In 2009 the Company completed approximately 93 gas conservation projects in its primary heavy oil operations, resulting in a reduction of 1.35 million tonnes/year of CO_2e. Over the past five years the Company has spent over $64.3 million in its primary heavy crude oil and in-situ oil sands operations to conserve the equivalent of over 8.7 million tonnes of CO_2e. The Company also monitors the performance of its compressor fleet which is continually modified and optimized for maximum efficiency. These programs also influence and direct the Company's plans for new projects and facilities. Horizon has incorporated advancements in technology to further reduce GHG emissions through maximizing heat integration, the use of cogeneration to meet steam and electricity demands and the design of the hydrogen production facility to enable CO_2 capture and the sequestration of CO_2 in oil sands tailings.

In its North Sea operations the Company continues to focus on implementing reduction programs based on efficiency audits of its major facilities. A number of CO2 reduction initiatives were carried out in 2009 including turbine washing on Ninian Northern Platform and an operational focus on reducing flaring. The Produced Water Re-injection on Ninian Central was made permanent in 2008. The Company continues to work at improving produced water quality and reducing oil discharged to sea.

For 2009, the Company's capital expenditures included $48 million for abandonment expenditures (2008 - $38 million).

The Company's estimated undiscounted ARO at December 31, 2009 was as follows:

Estimated ARO, undiscounted ($millions)	2009	2008
North America	$ 3,346	$ 3,072
Oil Sands Mining and Upgrading (1)	1,485	93
North Sea	1,522	1,216
Offshore West Africa	253	93
	6,606	4,474
North Sea PRT recovery	(568)	(529)
	$ 6,038	$ 3,945

(1) Prior period amounts have been reclassified to conform to the presentation adopted in 2009.

The estimate of ARO is based on estimates of future costs to abandon and restore the wells, production facilities and offshore production platforms. Factors that affect costs include number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs in accordance with present legislation and industry operating practice. The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production, lowering costs and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates. The future abandonment costs incurred in the North Sea are estimated to result in a PRT recovery of $568 million (2008 - $529 million), as abandonment costs are an allowable deduction in determining PRT and may be carried back to reclaim PRT previously paid. The expected PRT recovery reduces the Company's net undiscounted abandonment liability to $6,038 million (2008 - $3,945 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 crude oil and natural gas industry in Canada operates under government legislation and regulations, which govern exploration, development, production, refining, marketing, transportation, prevention of waste and other activities.

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

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

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

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

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

Effective January 1, 2009, changes were made to the Alberta royalty regime under the Alberta Royalty Framework ("ARF"). The ARF includes a number of changes to royalty rates for natural gas, conventional crude oil, and oil sands production. Under the ARF, royalties payable are variable according to commodity prices and the productivity and depth of wells. The ARF for conventional crude oil and natural gas operates based on sliding scales ranging up to 50% determined by commodity prices and well productivity.

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

In March 2009, the Government of Alberta announced new incentive programs to stimulate activity in Alberta. These programs provide for:

- A royalty credit of $200 per meter on new conventional crude oil and natural gas wells drilled between April 1, 2009 and March 31, 2010 to a maximum of 10% of conventional Crown royalties paid in Alberta.
- Reduced royalty rates that set the maximum royalty at 5% for the first 12 months of production, up to a maximum of 50,000 boe or 500 mmcfe for new conventional crude oil and natural gas wells that commence production between April 1, 2009 and March 31, 2010.

In June 2009, the Government of Alberta extended the two incentive programs described above by one year, to March 31, 2011.

In March 2010, the Government of Alberta further modified the conventional oil and natural gas royalty rates. These changes, effective January 1, 2011, include:

- Permanently imbedding in the royalty system the reduced royalty rate of a maximum of 5% on new natural gas and conventional oil wells with the same time and volume limits.
- Reducing the maximum royalty rate for conventional crude oil from 50% to 40% and reducing the maximum royalty rate for conventional and unconventional gas from 50% to 36%.

All royalty curves are to be finalized and announced by May 31, 2010.

Effective September 1, 2009, the Province of British Columbia announced an oil and gas stimulus package that includes:

A one-year, 2% royalty rate for all natural gas wells drilled between September 1, 2009 and June 30, 2010. Qualifying wells must commence production before December 31, 2010.

A permanent increase of 15% in the existing royalty holiday credits for the Deep Royalty Program.

A permanent qualification of horizontal wells drilled to a vertical depth between 1,900 and 2,300 meters into the Deep Royalty Program.

An additional $50 million allocation for the Infrastructure Royalty Credit Programs to stimulate investment in oil and gas roads and pipelines.

In addition to government royalties, the Company is subject to federal and provincial income taxes in Canada at a combined rate of approximately 29% after allowable deductions for 2009.

During 2007, the Canadian Federal Government enacted income tax rate changes which decrease the Federal corporate income tax rate over a five year period. The income tax rate in 2009 was 19%, is 18% in 2010 and decreases to 15% in 2012.

United Kingdom

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

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

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

Offshore West Africa

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

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

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

THE COMPANY

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

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

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

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

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

On January 1, 2004, CanNat and the Company amalgamated pursuant to the Business Corporations Act (Alberta) under the name Canadian Natural Resources Limited.

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

On January 1, 2008 Ranger Oil (International) Ltd., 764968 Alberta Inc., CNR International (Norway) Limited, Renata Resources Inc. and the Company amalgamated pursuant to the Business Corporations Act (Alberta) under the name Canadian Natural Resources Limited.

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

	Jurisdiction of Incorporation	% Ownership
Subsidiary		
CanNat Energy Inc.	Delaware	100
CNR (ECHO) Resources Inc.	Alberta	100
CNR International (U.K.) Investments Limited	England	100
CNR International (U.K.) Limited	England	100
CNR International Côte d'Ivoire SARL	Côte d'Ivoire	100
CNR International (Olowi) Limited	Bahamas	100
Horizon Construction Management Ltd.	Alberta	100
Partnership		
Canadian Natural Resources	Alberta	100
Canadian Natural Resources Northern Alberta Partnership	Alberta	100
Canadian Natural Resources 2005 Partnership	Alberta	100

Canadian Natural, as the managing partner, CNR (ECHO) Resources Inc. and Canadian Natural Resources 2005 Partnership are the partners of Canadian Natural Resources, a general partnership. Canadian Natural, as the managing partner, CNR (ECHO) Resources Inc., Canadian Natural Resources and Canadian Natural Resources 2005 Partnership are partners of Canadian Natural Resources Northern Alberta Partnership, a general partnership. Canadian Natural, as the managing partner, and CNR (ECHO) Resources Inc. are the partners of Canadian Natural Resources 2005 Partnership.

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

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

GENERAL DEVELOPMENT OF THE BUSINESS – THREE YEAR HISTORY

2007

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

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

The Company completed 67 transactions in the normal course to acquire additional interests in crude oil and natural gas properties. The aggregate net expenditure of the transactions was $71 million. The properties acquired are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. As well, the Company participated in 27 transactions to dispose of non-core operated and non-operated properties for proceeds of $110 million.

2008

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

In the third quarter of 2008, the Company committed 120,000 bbl/d to the Keystone Pipeline US Gulf Coast Expansion for a 20 year period, subject to regulatory approval. Concurrently the Company entered into a 20 year supply agreement with a major US refiner for 100,000 bbl/d of heavy crude oil to US Gulf Coast refineries. Deliveries under the agreements are expected to commence in 2012 contingent upon Keystone receiving the regulatory approvals for the pipeline expansion and subsequent completion of the expansion.

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

The Company completed 55 transactions in the normal course to acquire additional interests in crude oil and natural gas properties. The aggregate net expenditure of the transactions was $356 million. The properties acquired are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. As well, the Company participated in 22 transactions to dispose of non-core operated and non-operated properties for proceeds of $20 million.

2009

Construction of Phase 1 of Horizon was completed and commercial operations began.

The Company repaid the $2,350 million remaining on the non-revolving syndicated credit facility related to the 2006 acquisition of ACC and cancelled the facility.

The Company completed 59 transactions in the normal course to acquire additional interests in crude oil and natural gas properties. The aggregate net expenditure of the transactions was $42 million. The properties acquired are located in the Company's principal operating regions and are comprised of producing and non-producing leases together with related facilities. As well, the Company participated in 24 transactions to dispose of non-core operated and non-operated properties and seismic for proceeds of $36 million.

2010 Outlook

In January 2010, the Company announced that, together with North West Upgrading Inc. (“NWU”), it had submitted a joint proposal to the Alberta Government to construct and operate a bitumen refinery near Redwater, Alberta. This proposal was submitted in response to a request for proposal under the Alberta Royalty Framework’s Bitumen Royalty in Kind (BRIK) program. Canadian Natural agreed, subject to a number of conditions, to acquire 50% of the assets of NWU and form a partnership to construct and operate the facility. Closing of the acquisition is targeted for later in 2010 and remains subject to the satisfaction of a number of conditions. Phase 1 of the proposed facility includes a one step conversion process of 50,000 bbl/d of bitumen to finished products and an integrated CO2 management solution. The proposed facility can be expanded in two additional identical phases of 50,000 bbl/d of bitumen, provided economics justify the investment. Canadian Natural has agreed to supply 12,500 bbl/d of its own bitumen production to Phase 1 of the proposed facility.

For 2010, the Company’s overall conventional drilling activity in North America is expected to comprise approximately 93 natural gas wells and 966 crude oil wells, excluding stratigraphic and service wells. Conventional capital expenditures in North America for 2010 are currently expected to be approximately $2.6 billion, excluding property acquisitions and dispositions. Capital expenditures related to Oil Sands Mining and Upgrading are expected to be $738 million excluding capitalized interest.

For 2010, capital expenditures in the North Sea are estimated to be $199 million and are expected to be $264 million for Offshore West Africa.

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, and natural gas production. The Company’s principal core regions of operations are western Canada, the United Kingdom sector of the North Sea and Offshore West Africa.

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

The Company has a full complement of management, technical and support staff to pursue these objectives. As at December 31, 2009, the Company had 3,827 full time equivalent permanent employees in North America and 337 full time equivalent permanent employees in its international operations.

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

The Company’s business approach is to maintain large project inventories and production diversification among each of the commodities it produces namely: natural gas, light/medium crude oil and NGLs, Pelican Lake crude oil (14-17º API oil, which receives medium quality crude netbacks due to lower production costs and lower royalty rates), primary heavy crude oil, thermal heavy crude oil and SCO. The Company’s operations are centered 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 38% of 2009 production. Virtually all of the Company's natural gas and NGLs production is located in the Canadian provinces of Alberta, British Columbia and Saskatchewan and is marketed in Canada and the United States. Light/medium crude oil and NGLs, representing 21% of 2009 production, is located principally in the Company's North Sea and Offshore West Africa properties, with additional production in the provinces of Saskatchewan, British Columbia and Alberta. Primary and thermal heavy crude oil operations in the provinces of Alberta and Saskatchewan account for 26% of 2009 production. SCO accounts for approximately 9% of 2009 production. Pelican Lake crude oil, which accounts for 6% of 2009 production, is produced from the Pelican Lake area in northern Alberta. This production is developed through a staged horizontal drilling program complimented by water and polymer flooding. Midstream assets, comprised of three crude oil pipelines and an electricity co-generation facility, provide cost effective infrastructure supporting the primary and thermal heavy and Pelican Lake crude oil operations.

With approximately 11 million net acres of core undeveloped land base, the Company believes it has sufficient project portfolios in each of the product offerings to provide growth for the next several years.

A. PRINCIPAL CRUDE OIL AND NATURAL GAS PROPERTIES

Daily Production

Set forth below is a summary of the crude oil, NGLs and natural gas properties for the fiscal years ended December 31, 2009 and 2008.

	2009 Average Daily Production Rates		2008 Average Daily Production Rates	
Region	Crude oil & NGLs (mbbl)	Natural gas (mmcf)	Crude oil & NGLs (mbbl)	Natural gas (mmcf)
North America				
Northeast British Columbia	5.5	329	5.9	377
Northwest Alberta	14.8	455	16.4	531
Northern Plains	194.6	341	200.7	382
Southern Plains	11.4	158	12.2	177
Southeast Saskatchewan	7.9	3	8.4	3
Oil sands Mining & Upgrading	50.3	-	-	-
Non-core regions	0.3	1	0.2	2
North America Total	284.8	1,287	243.8	1,472
International				
North Sea UK Sector	37.8	10	45.3	10
Offshore West Africa				
Côte d'Ivoire	30.3	18	26.6	13
Gabon	2.6	-	-	-
International Total	70.7	28	71.9	23
Company Total	355.5	1,315	315.7	1,495

Developed and Undeveloped Acreage

The following table summarizes the Company's landholdings as at December 31, 2009.

	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
Region (thousands of acres)	Gross	Net	Gross	Net	Gross	Net	%
North America							
Northeast British Columbia	1,493	1,132	2,838	2,068	4,331	3,200	74
Northwest Alberta	1,229	883	1,531	1,154	2,760	2,037	74
Northern Plains	4,111	3,351	6,696	5,885	10,807	9,236	85
Southern Plains	1,530	1,216	950	804	2,480	2,020	81
Southeast Saskatchewan	93	76	154	139	247	215	87
Thermal In-Situ Oil Sands	29	29	588	486	617	515	83
Oil Sands Mining & Upgrading	1	1	115	115	116	116	100
Non-core regions	42	14	1,341	201	1,383	215	16
North America Total	8,528	6,702	14,213	10,852	22,741	17,554	77
International							
North Sea UK Sector	68	57	184	150	252	207	82
Offshore West Africa							
Côte d'Ivoire	10	6	92	54	102	60	59
Gabon	2	2	150	138	152	140	92
Non-core regions							
South Africa	-	-	4,002	4,002	4,002	4,002	100
International Total	80	65	4,428	4,344	4,508	4,409	98
Company Total	8,608	6,767	18,641	15,196	27,249	21,963	81

Drilling Activity

Set forth below are summaries of crude oil, NGLs and natural gas drilling activities of the Company for the fiscal years ended December 31, 2009, 2008 and 2007 by geographic region.

		2009									
		Exploratory					Development				
		Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total	Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total
North America											
Northeast British Columbia	Gross	-	1.0	3.0	-	4.0	-	20.0	1.0	-	21.0
	Net	-	0.5	2.4	-	2.9	-	17.6	1.0	-	18.6
Northwest Alberta	Gross	4.0	24.0	-	-	28.0	4.0	24.0	1.0	-	29.0
	Net	3.5	22.3	-	-	25.8	3.3	23.4	1.0	-	27.7
Northern Plains	Gross	39.0	8.0	6.0	7.0	60.0	601.0	37.0	35.0	203.0	876.0
	Net	38.5	7.1	6.0	7.0	58.6	565.9	27.9	33.5	203.0	830.3
Southern Plains	Gross	3.0	2.0	1.0	-	6.0	5.0	25.0	1.0	1.0	32.0
	Net	2.1	2.0	1.0	-	5.1	3.6	8.3	1.0	1.0	13.9
Southeast Saskatchewan	Gross	3.0	-	-	-	3.0	20.0	-	-	2.0	22.0
	Net	2.1	-	-	-	2.1	18.4	-	-	2.0	20.4
Oil Sands Mining and Upgrading	Gross	-	-	-	-	-	-	-	-	115.0	115.0
	Net	-	-	-	-	-	-	-	-	115.0	115.0
Non-core Regions	Gross	-	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-	-
North America Total	Gross	49.0	35.0	10.0	7.0	101.0	630.0	106.0	38.0	321.0	1,095.0
	Net	46.2	31.9	9.4	7.0	94.5	591.2	77.2	36.5	321.0	1,025.9
North Sea UK Sector	Gross	-	-	1.0	-	1.0	1.0	-	-	-	1.0
	Net	-	-	0.3	-	0.3	0.9	-	-	-	0.9
Offshore West Africa	Gross	-	-	-	-	-	6.0	-	-	1.0	7.0
	Net	-	-	-	-	-	5.2	-	-	0.9	6.1
Company Total	Gross	49.0	35.0	11.0	7.0	102.0	637.0	106.0	38.0	322.0	1,103.0
	Net	46.2	31.9	9.7	7.0	94.8	597.3	77.2	36.5	321.9	1,032.9

Total success rate excluding service and stratigraphic test wells for 2009 is 94% (2008 - 96%, 2007 - 91%)

At December 31, 2009, Canadian Natural was in the process of drilling 10 gross wells (9.5 net wells) in Canada and 1 gross well (0.93 net wells) in Offshore West Africa.

		2008									
		Exploratory					Development				
		Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total	Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total
North America											
Northeast British Columbia	Gross	-	2.0	2.0	-	4.0	-	26.0	4.0	-	30.0
	Net	-	1.5	1.5	-	3.0	-	22.5	1.9	-	24.4
Northwest Alberta	Gross	1.0	14.0	1.0	-	16.0	14.0	62.0	3.0	3.0	82.0
	Net	0.6	12.6	0.9	-	14.1	8.9	54.0	2.6	2.2	67.7
Northern Plains	Gross	27.0	14.0	5.0	-	46.0	583.0	131.0	22.0	33.0	769.0
	Net	26.3	11.4	5.0	-	42.7	557.3	88.4	21.5	32.4	699.6
Southern Plains	Gross	4.0	6.0	1.0	-	11.0	29.0	153.0	1.0	-	183.0
	Net	4.0	6.0	1.0	-	11.0	26.9	72.8	1.0	-	100.7
Southeast Saskatchewan	Gross	6.0	-	2.0	-	8.0	57.0	-	-	2.0	59.0
	Net	4.6	-	2.0	-	6.6	48.9	-	-	1.7	50.6
Oil Sands Mining and Upgrading	Gross	-	-	-	-	-	-	-	-	92.0	92.0
	Net	-	-	-	-	-	-	-	-	92.0	92.0
Non-core Regions	Gross	-	-	-	-	-	-	3.0	2.0	-	5.0
	Net	-	-	-	-	-	-	0.1	0.4	-	0.5
North America Total	Gross	38.0	36.0	11.0	-	85.0	683.0	375.0	32.0	130.0	1,220.0
	Net	35.5	31.5	10.4	-	77.4	642.0	237.8	27.4	128.3	1,035.5
North Sea UK Sector	Gross	1.0	-	-	-	1.0	2.0	-	1.0	1.0	4.0
	Net	0.8	-	-	-	0.8	1.6	-	0.8	0.9	3.3
Offshore West Africa	Gross	-	-	-	-	-	4.0	-	-	2.0	6.0
	Net	-	-	-	-	-	2.3	-	-	1.8	4.1
Company Total	Gross	39.0	36.0	11.0	-	86.0	689.0	375.0	33.0	133.0	1,230.0
	Net	36.3	31.5	10.4	-	78.2	645.9	237.8	28.2	131.0	1,042.9

		2007									
		Exploratory					Development				
		Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total	Crude Oil	Natural Gas	Dry	Service/ Stratigraphic	Total
North America											
Northeast British Columbia	Gross	-	7.0	7.0	-	14.0	3.0	45.0	12.0	-	60.0
	Net	-	7.0	6.0	-	13.0	2.9	35.1	10.1	-	48.1
Northwest Alberta	Gross	1.0	23.0	5.0	-	29.0	21.0	102.0	14.0	2.0	139.0
	Net	1.0	16.4	3.8	-	21.2	12.1	82.1	8.9	1.5	104.6
Northern Plains	Gross	26.0	31.0	20.0	97.0	174.0	545.0	82.0	44.0	49.0	720.0
	Net	23.8	24.7	19.4	97.0	164.9	500.6	70.9	42.4	48.8	662.7
Southern Plains	Gross	1.0	14.0	1.0	-	16.0	19.0	174.0	2.0	1.0	196.0
	Net	1.0	13.4	1.0	-	15.4	18.1	134.1	0.6	1.0	153.8
Southeast Saskatchewan	Gross	1.0	-	-	-	1.0	27.0	-	2.0	4.0	33.0
	Net	1.0	-	-	-	1.0	23.0	-	0.4	4.0	27.4
Oil Sands Mining and Upgrading	Gross	-	-	-	-	-	-	-	-	98.0	98.0
	Net	-	-	-	-	-	-	-	-	98.0	98.0
Non-core Regions	Gross	-	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-	-
North America Total	Gross	29.0	75.0	33.0	97.0	234.0	615.0	403.0	74.0	154.0	1,246.0
	Net	26.8	61.5	30.2	97.0	215.5	556.7	322.2	62.4	153.3	1,094.6
North Sea UK Sector	Gross	-	-	-	-	-	4.0	-	-	4.0	8.0
	Net	-	-	-	-	-	3.7	-	-	3.5	7.2
Offshore West Africa	Gross	-	-	-	-	-	7.0	-	-	1.0	8.0
	Net	-	-	-	-	-	4.1	-	-	0.6	4.7
Company Total	Gross	29.0	75.0	33.0	97.0	234.0	626.0	403.0	74.0	159.0	1,262.0
	Net	26.8	61.5	30.2	97.0	215.5	564.5	322.2	62.4	157.4	1,106.5

Productive Crude Oil & Natural Gas Wells

Set forth below is a summary of the number of gross and net wells of the Company that were producing or mechanically capable of producing as of December 31, 2009.

	Natural gas wells		Crude oil wells		Total wells	
	Gross	Net	Gross	Net	Gross	Net
Canada						
Northeast British Columbia	1,545	1,281.2	218	187.4	1,763	1,468.6
Northwest Alberta	2,138	1,677.5	555	342.4	2,693	2,019.9
Northern Plains	3,788	3,077.9	6,009	5,529.6	9,797	8,607.5
Southern Plains	7,366	6,094.4	1,227	1,121.5	8,593	7,215.9
Southeast Saskatchewan	-	-	1,198	876.6	1,198	876.6
Non-core regions	77	20.9	121	24.8	198	45.7
Total Canada	14,914	12,151.9	9,328	8,082.3	24,242	20,234.2
United States	3	0.3	2	0.3	5	0.6
North Sea UK Sector	2	0.1	108	91.1	110	91.2
Offshore West Africa						
Gabon	-	-	5	4.6	5	4.6
Côte d'Ivoire	-	-	23	13.4	23	13.4
Total	14,919	12,152.3	9,466	8,191.7	24,385	20,344.0

Any reserves data in the following property report is based on the applicable independent engineering report. See the section entitled "Crude Oil, NGLs and Natural Gas Reserves" in this Annual Information Form.

Northeast British Columbia

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

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

Northwest Alberta

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

Northern Plains

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

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

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

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

Included in the northern part of this region, approximately 200 miles north of Edmonton, are the Company's holdings at Pelican Lake. These assets produce crude oil from the Wabasca formation with gravities of 14°-17° API. Production costs are low due to the absence of sand production, its associated disposal requirements and the gathering and pipeline facilities in place. The Company has the major ownership position in the necessary infrastructure, including roads, drilling pads, gathering and sales pipelines, batteries, gas plants and compressors, to ensure economic development of the large crude oil pool located on the lands, including the 62% owned and operated Pelican Lake Pipeline. The Company holds and controls approximately 75% of the known Wabasca crude oil pool in the Pelican Lake area. It is estimated the Wabasca pool contains approximately four billion barrels of original crude oil in place but is only expected to achieve less than a 5% average recovery factor using primary production on the Company's developed leases. The Company is using an Enhanced Oil Recovery ("EOR") scheme through both water and polymer flooding to increase the ultimate recoveries from the field. To date approximately 28% of the field has been converted to waterflood and there are 227 polymer injection wells supporting approximately 259 production wells. Pelican Lake production averaged approximately 37,000 bbl/d in 2009 (2008-37,000 bbl/d). The Company is continuing to drill and convert wells in 2010 and anticipates approximately 40% of the field will be converted to polymer injection by the end of 2010.

Production from the 100% owned Primrose and Wolf Lake Fields located near Bonnyville, Alberta involves processes that utilize steam to increase the recovery of the heavy (10°-11°API) crude oil. The two processes employed by the Company are Cyclic Steam Stimulation ("CSS") and Steam Assisted Gravity Drainage ("SAGD"). Both recovery processes inject steam to heat the heavy crude oil deposits, reducing the oil viscosity and thereby improving its flow characteristics. There is also an infrastructure of gathering systems, a processing plant with a capacity of 119,500 bbl/d, and the 15% Company owned Cold Lake Pipeline. The Company also holds a 50% interest in a co-generation facility capable of producing 84 megawatts of electricity for the Company's use and sale into the Alberta power grid at pool prices. Since acquiring the assets from BP Amoco in 1999, the Company has successfully converted the field from low-pressure steaming to high-pressure steaming. This conversion resulted in a significant improvement in well productivity and in ultimate oil recovery. A mature SAGD heavy oil project in which the Company holds a 50% interest is also in operation in the Saskatchewan portion of this region. The Regulatory application for the Kirby In-Situ Oil Sands Project located approximately 85 km northeast of Lac La Biche was submitted in September 2007 outlining the Company's plan to build a 45,000 bbl/d in-situ oil sands project. Canadian Natural is proceeding with the detailed engineering and design work and project sanction and scope is targeted for late 2010.

In 2007, the Company received regulatory approval for its Primrose East expansion, a new facility located about 15 kilometers from its existing Primrose South steam plant and 25 kilometers from its Wolf Lake central processing facility. The Company began construction in 2007 and first oil production was achieved in late October 2008. The expansion added 40,000 bbl/d of capacity. During the first quarter of 2009, operational issues on one of the pads caused steaming to cease on all well pads resulting in the Company switching from the steaming cycle to the production cycle ahead of schedule. The Company formalized and received approval for a plan to begin diagnostic steaming which commenced in August 2009 and is proceeding according to plan with steaming targeted to ramp up again in 2010.

Southern Plains and Southeast Saskatchewan

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

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

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

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

Oil Sands Mining and Upgrading

Canadian Natural owns a 100% working interest in its Athabasca Oil Sands leases in northern Alberta, of which a portion (being lease 18) is subject to a 5% net carried interest in the bitumen development. Horizon is located on these leases, about 70 kilometers north of Fort McMurray. Figure 1 shows the location of Horizon within Alberta and within the region. Figure 2 shows the mining area associated with the reserves and the general layout of the site. Table 1 describes the leases the Company holds in the region.

Figure 1 - Location of Horizon Oil Sands

Figure 2 - Horizon Oil Sands Resource Areas and General Layout

Table 1 - Canadian Natural Athabasca Region Oil Sand Leases

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

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

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

Horizon Oil Sands includes surface oil sands mining, bitumen extraction, bitumen upgrading and associated infrastructure. Mining of the oil sands is done using conventional truck and shovel technology. The ore is then processed through extraction and froth treatment facilities to produce bitumen, which is upgraded on-site into 34o API SCO. The upgrader capacity is 110,000 bbl/day of SCO. The SCO is transported from the site by the Horizon Pipeline with a design capacity of 232,000 bbl/day to the Edmonton area for distribution. An on-site cogeneration plant with a design capacity of 115 MW provides power and steam for the operation.

In June 2002, Canadian Natural filed an application with the Energy Resources Conservation Board (ERCB) (formerly the Alberta Energy and Utilities Board) for regulatory approval of Horizon. 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”) established by the ERCB and the Government of Canada examined the project in a public hearing in September 2003. The Panel issued its decision report in January 2004, finding Horizon was in the public interest. An Alberta Order-in-Council approval was received from the ERCB 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. In 2009, Canadian Natural submitted an administrative amendment to its ERCB approval to incorporate changes to development timing at Horizon and approval is expected in 2010. A Tailings Management Plan was also submitted to the ERCB in September 2009 and approval is expected in 2010.

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

First SCO production was achieved during 2009 and the Company continues to ramp up to sustainable production of 110,000 bbl/d of SCO which is expected to be achieved in 2010.

Engineering and procurement for Tranche 2 of the Phase 2/3 expansion is progressing with a focus on increasing reliability and uptime. Tranches 3 and 4 of Phase 2/3 continue to be re-profiled with the Company continuing to work on completing its lessons learned from the construction of Phase 1 and implementing these into the development of future expansions.

Regional and Horizon Oil Sands Geology

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

In the area of Horizon, 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 clays that reside above the unconformity with the underlying Upper Devonian carbonates (limestone) of the Waterways Formation. The McMurray Formation at the site of Horizon 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 Horizon’s oil sands resource is found within the lower and middle McMurray. The general stratigraphy of Horizon is shown in Figure 3.

Figure 3 - General Stratigraphy of Horizon

United Kingdom North Sea

Through its wholly owned subsidiary CNR International (U.K.) Limited, formerly Ranger Oil (U.K.) Limited, the Company has operated in the North Sea for over 30 years and has developed a significant database, extensive operating experience and an experienced staff. In 2009, the Company produced from 13 crude oil fields.

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

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

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

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

During 2009, one production well was completed at Ninian. The Company continued to focus on maturing and high grading infill drilling opportunities in preparation for the restart of platform drilling operations in the second quarter of 2010.

The Company continued with its planned investment in its long-term facilities and infrastructure strategy and successfully carried out maintenance turnarounds at four of the five installations during the year.

In the first quarter 2009, the Company commenced drilling on Deep Banff a high temperature, high pressure, natural gas exploration well which did not find commercial hydrocarbons and was plugged and abandoned early in the third quarter of 2009.

Offshore West Africa

Côte d'Ivoire

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

The Company has a 58.7% operated interested in the Espoir Field in Block CI-26 which is located in water depths ranging from 100 to 700 meters. Production from East Espoir commenced in 2002 and development drilling of West Espoir was completed in 2008. Crude oil from the East and West Espoir Fields is produced to an FPSO with the associated natural gas delivered onshore through a subsea pipeline for local power generation. Progress on the Facility Upgrade Project to increase processing capacity of the FPSO has reverted to the original schedule to accommodate effective utilization of the installation vessel at the Olowi Field. Commissioning is targeted to be complete during the second quarter of 2010.

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

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

Gabon

The Company has a permit comprising a 92.5% operating interest in the production sharing agreement for the block containing the Olowi Field. The field is located about 20 kilometers from the Gabonese coast and in 30 meters water depth. Delays in construction of the FPSO which arrived on location in February 2009, resulted in first oil commencing in the second quarter of 2009. Production to date from the first platform is below expectations. The Company is currently reviewing drilling results and production data in order to develop appropriate remediation strategies and determine the impact on future production from the field, the impact on recoverable reserves and the scope of the overall development plan. The Company continues drilling the next scheduled platform with production targeted for the second quarter of 2010.

B. CRUDE OIL, NGLs, AND NATURAL GAS RESERVES

For the year ended December 31, 2009, the Company retained qualified independent reserves evaluators, Sproule Associates Limited ("Sproule"), and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved, as well as probable crude oil, synthetic crude oil, bitumen, coal bed methane, NGLs and natural gas reserves and prepare Evaluation Reports on these reserves. Sproule evaluated and reviewed all of the Company's crude oil, bitumen, natural gas, coal bed methane and NGLs reserves. GLJ evaluated all of the synthetic crude oil reserves related to the Company's oil sands mine. The Company has been granted an exemption from certain provisions of National Instrument 51-101 – "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute SEC requirements under Regulations S-K and S-X for certain disclosures required under NI 51-101. On December 31, 2008, the SEC released its final rules for the modernization of oil and gas reporting ("Final Rule"). The material changes include the ability to include oil sands mining as an oil and gas activity, ability to use reliable technology to establish undeveloped reserves, the optional ability to report probable reserves, the requirement to track undeveloped locations, as well as the directive to use 12-month average prices and current costs. These resulting changes are more in line with NI 51-101 however there are material differences to the type of volumes disclosed and the basis from which the volumes are determined. NI 51-101 requires gross reserves and future net revenue under forecast pricing and costs, however, the SEC, as discussed, requires disclosure of net reserves, after royalties, under 12-month average prices and current costs. The difference between the reported numbers under the two disclosure standards can be material.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with Sproule and GLJ as to the Company's reserves.

The Company annually discloses proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs as mandated by the SEC in the supplementary crude oil and natural gas information section of the Company's Annual Report and in its annual Form 40-F filing with the SEC.

There is no assurance that the price and cost assumptions contained in either the 12-month average case or forecast case will be attained and variances could be material.

In the ordinary course of business, the Company has a number of delivery commitments to provide crude oil and natural gas under existing contracts and agreements. The Company has sufficient crude oil and natural gas reserves to meet these commitments.

Summary of Crude Oil, NGLs and Natural Gas Net Reserves

The following tables summarize the evaluations of the reserves as at December 31, 2009.

Reserves Category	Crude Oil & NGLs (mmbbl)	Bitumen (mmbbl)	Synthetic Crude Oil (mmbbl)	Total Liquids (mmbbl)	Natural Gas (bcf)	Total Reserves (mmboe)
PROVED						
Developed:						
North America	204	268	1,589	2,061	2,333	2,450
International						
United Kingdom – North Sea	94	-	-	94	45	101
Offshore West Africa	106	-	-	106	81	120
Total Developed:	404	268	1,589	2,261	2,459	2,671
Undeveloped:						
North America	115	427	61	603	694	719
International						
United Kingdom – North Sea	146	-	-	146	22	149
Offshore West Africa	17	-	-	17	4	18
Total Undeveloped:	278	427	61	766	720	886
TOTAL PROVED:	682	695	1,650	3,027	3,179	3,557

Reserves Category	Crude Oil & NGLs (mmbbl)	Bitumen (mmbbl)	Synthetic Crude Oil (mmbbl)	Total Liquids (mmbbl)	Natural Gas (bcf)	Total Reserves (mmboe)
PROBABLE						
Developed:						
North America	72	23	79	174	709	292
International						
United Kingdom – North Sea	35	-	-	35	8	36
Offshore West Africa	5	-	-	5	26	9
Total Developed:	112	23	79	214	743	337
Undeveloped:						
North America	56	495	783	1,334	256	1,377
International						
United Kingdom – North Sea	112	-	-	112	19	116
Offshore West Africa	51	-	-	51	13	53
Total Undeveloped:	219	495	783	1,497	288	1,546
TOTAL PROBABLE:	331	518	862	1,711	1,031	1,883

Undeveloped Reserves

The Company's proved undeveloped reserves make up 25% of our 3,557 mmboe proved reserves. In 2009, the Company spent $774 million to convert 135 mmboe of pre-existing undeveloped reserves to developed reserves. The total estimated future capital, based on 2009 costs, required to develop the Company's 886 mmboe proved undeveloped reserves is $9.4 billion dollars. The total estimated future capital, based on 2009 costs, required to develop the Company's 1,546 mmboe of probable undeveloped reserves is $3.5 billion dollars.

Reserves which have remained undeveloped for 5 years or more are 363 mmboe of proved undeveloped and 404 mmboe of probable undeveloped. Of these reserves, 354 mmboe proved undeveloped and 402 mmboe probable undeveloped are associated with our long life large project thermal reserves. The remaining undeveloped reserves are associated with our offshore international projects and future uphole potential reserves associated with existing producing well bores.

Sensitivity of Reserves to Prices by Principal Product Type

Price Case	Proved Reserves					
	Crude Oil & NGLs (mmbbl)	Bitumen (mmbbl)	Synthetic Crude Oil (mmbbl)	Total Liquids (mmbbl)	Natural Gas (bcf)	Total Reserves (mmboe)
December 31, 2009 Forecast Pricing	684	652	1,564	2,900	3,491	3,482

Price Case	Probable Reserves					
	Crude Oil & NGLs (mmbbl)	Bitumen (mmbbl)	Synthetic Crude Oil (mmbbl)	Total Liquids (mmbbl)	Natural Gas (bcf)	Total Reserves (mmboe)
December 31, 2009 Forecast Pricing	295	482	820	1,597	1,174	1,793

NOTES

1. "Net" reserves mean the Company's gross reserves less all royalties payable to others plus royalties receivable from others.

2. Bitumen as defined by the SEC, under the Final Rule, "is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis." Under this definition, all the Company's primary and thermal heavy crude oil reserves have been reclassified as bitumen. Prior to December 31, 2009, these reserves would have been classified within the Company's conventional crude oil and NGLs totals.

3. Prior to December 31, 2009, the Company's Horizon SCO reserves were reported separately in accordance to the SEC's Industry Guide 7. With SEC's Final Rule in effect January 1, 2010, for fiscal years ending on or after December 31, 2009, this SCO is now included in the Company's crude oil and natural gas reserve totals.

4. "Proved" oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. Under the Final Rule it is required that these reserves be evaluated using 12-month average prices and current costs and be disclosed net of royalties. The Company has also provided these reserves using forecast prices and costs in a sensitivity table as permitted by the SEC under the Final Rule.

5. "Developed" oil and gas reserves are reserves of any category that are expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of required equipment is relatively minor to the cost of drilling a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

6. "Undeveloped" reserves are reserves of any category that 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 directly offsetting development spacing areas that are reasonably certain of production when drilled unless reliable technology exists that establishes reasonable certainty of economic producibilty at greater distances.

7. ”Probable” reserves estimates are provided as optional disclosure under the Final Rule. Probable reserves are those additional reserves that are less certain to be recovered than proved, however, together with proved are as likely as not to be recovered. Under the Final Rule it is required that these be evaluated using 12-month average prices and current costs and be disclosed net of royalties. The reserve estimates could be materially different from the quantities ultimately realized. The Company has also provided these reserves using forecast prices and costs in a sensitivity table as permitted by the SEC under the Final Rule.

8. The 12-month average price and current cost case assumes that the 2009 average prices adjusted for quality and transportation, as well as the 2009 costs, are held constant over life. The 12-month average prices are determined by calculating the arithmetic unweighted average of the first-day-of-month price for each month of the 12-month period prior to December 31, 2009. These 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 2009 values shown below. In addition, operating and capital costs have not been increased on an inflationary basis. The following table outlines the prices calculated and used (based on a foreign exchange rate of US$0.87/C$1.00):

	Natural gas 12-month average price				Crude oil & NGLs 12-month average price				
(Year)	Company average price (C$/mcf)	Henry Hub Louisiana (US$/mmbtu)	AECO (C$/mmbtu)	Huntingdon/Sumas (C$/mmbtu)	Company average price (C$/bbl)	WTI @ Cushing(1) (US$/bbl)	WCS(2) (C$/bbl)	Edmonton Par(3) (C$/bbl)	North Sea Brent (US$/bbl)
2009	4.02	3.87	3.87	3.92	59.39	61.18	58.49	66.07	59.91

(1) "WTI @ Cushing" refers to the price of West Texas Intermediate crude oil at Cushing, Oklahoma.
(2) "WCS" refers to the price of Western Canada Select at Hardisty, Alberta.
(3) "Edmonton Par" refers to the price of light gravity (40° API), low sulphur content crude oil at Edmonton, Alberta.

9. The forecast price and cost case assumes 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. Capital and operating costs are escalated at 2% per year. Future crude oil, NGLs and natural gas price forecasts were based on Sproule's December 31, 2009 crude oil, NGLs and natural gas pricing model.

The Company's weighted average crude oil and NGLs price and the weighted average natural gas price in the 2009 evaluation for 2010 were $75.92 per barrel and $5.48 per mcf respectively. The crude oil, NGLs and natural gas forecast prices used in the Evaluation Reports are as follows:

	Natural gas				Crude oil & NGLs				
(Year)	Company average price (C$/mcf)	Henry Hub Louisiana (US$/mmbtu)	AECO (C$/mmbtu)	Huntingdon/ Sumas (C$/mmbtu)	Company average price (C$/bbl)	WTI @ Cushing (US$/bbl)	WCS (C$/bbl)	Edmonton Par (C$/bbl)	North Sea Brent (US$/bbl)
2010	5.48	5.70	5.36	5.61	75.92	79.17	74.14	84.25	77.92
2011	6.36	6.48	6.21	6.46	80.82	84.46	78.29	89.99	83.19
2012	6.60	6.70	6.44	6.69	82.83	86.89	76.86	92.61	85.59
2013	7.43	7.43	7.23	7.48	85.32	90.20	78.87	96.19	88.88
2014	8.20	8.12	7.98	8.23	87.11	92.01	79.49	98.13	90.65
2015	8.39	8.28	8.16	8.41	89.18	93.85	81.09	100.11	92.47
2016	8.53	8.45	8.34	8.59	90.73	95.72	82.73	102.13	94.32
2017	8.70	8.62	8.52	8.77	93.64	97.64	84.40	104.19	96.20
2018	8.87	8.79	8.71	8.96	95.97	99.59	86.10	106.30	98.13
2019	9.06	8.96	8.90	9.15	99.53	101.58	87.84	108.44	100.09

2020	9.26	9.14	9.10	9.35	101.42	103.61	89.61	110.63	102.09

Note: Foreign exchange rate used was US$0.92/C$1.00.

10. The estimated total development capital costs, net to the Company, necessary to develop the reported reserves, excluding abandonment and reclamation cost associated with existing assets, are as follows:

	Proved		Probable	
(C$millions)	12-Month Average Price Case	Forecast Price Case	12-Month Average Price Case	Forecast Price Case
2010	2,003	2,033	298	292
2011	2,250	2,382	1,578	1,615
2012	1,868	2,028	2,616	2,735
2013	1,711	1,907	3,552	3,832
2014	1,173	1,331	3,155	3,419
2015	941	1,115	1,557	1,727
2016	1,023	1,200	1,369	1,551
2017	736	894	285	331
2018	564	704	309	346
2019	575	701	283	341
2020	533	655	273	376
Thereafter	8,832	15,742	5,226	6,855

11. 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 GLJ and Sproule to be reasonable.

A report on reserves data by the independent qualified reserves evaluators are provided in Schedule “A” to this Annual Information Form. A report by the Company’s management and directors on crude oil and natural gas disclosure is provided in Schedule “B” to this Annual Information Form. The Company does not file estimates of its total crude oil and natural gas reserves with any U. S. agency or federal authority other than the SEC.

C. RECONCILIATION OF CHANGES IN NET RESERVES

The following table summarizes the changes during the past year in reserves after deduction of royalties payable to others and using 12-month average prices and costs for 2009 and year end prices and costs for 2008 and 2007.

Crude Oil and NGLs Reserves Reconciliation, Net of Royalties

	North America				International		Total
Net Proved Reserves (mmbbl)	Synthetic Crude Oil(1)	Bitumen	Crude Oil & NGLs	Total	North Sea	Offshore West Africa	
Reserves, December 31, 2007(1)				920	310	128	1,358
Extensions and discoveries				51	-	-	51
Improved recovery				17	6	4	27
Purchases of reserves in place				-	-	-	-
Sales of reserves in place				-	-	-	-
Production				(76)	(17)	(8)	(101)
Economic revisions due to prices				28	(81)	8	(45)
Revisions of prior estimates				8	38	10	56
Reserves, December 31, 2008(1)	–	690	258	948	256	142	1,346
Extensions and discoveries	–	24	6	30	–	–	30
Improved recovery	–	8	75	83	–	–	83
SEC Reliable Technology (2)	–	7	–	7	–	–	7
SEC Rule Transition (3)	1,650	–	–	1,650	–	–	1,650
Purchases of reserves in place	–	–	1	1	–	–	1
Sales of reserves in place	–	–	–	–	–	–	–
Production	–	(49)	(24)	(73)	(14)	(11)	(98)
Economic revisions due to prices	–	(64)	(8)	(72)	57	(4)	(19)
Revisions of prior estimates	–	79	11	90	(59)	(4)	27
Reserves, December 31, 2009	1,650	695	319	2,664	240	123	3,027

Net Probable Reserves (mmbbl)(4)	North America Synthetic Crude Oil (1)	Bitumen	Crude Oil & NGLs	Total	International North Sea	Offshore West Africa	Total
Reserves, December 31, 2007(1)				625	95	58	778
Extensions and discoveries				25	-	-	25
Improved recovery				15	(2)	(4)	9
Purchases of reserves in place				6	-	-	6
Sales of reserves in place				-	-	-	-
Production				-	-	-	-
Economic revisions due to prices				31	36	-	67
Revisions of prior estimates				(51)	14	(5)	(42)
Reserves, December 31, 2008(1)	-	548	103	651	143	49	843
Extensions and discoveries	-	11	5	16	-	-	16
Improved recovery	-	4	37	41	-	-	41
SEC Reliable Technology (2)	-	3	-	3	-	-	3
SEC Rule Transition (3)	862	-	-	862	-	-	862
Purchases of reserves in place	-	-	1	1	-	-	1
Sales of reserves in place	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-
Economic revisions due to prices	-	(71)	5	(66)	(44)	(2)	(112)
Revisions of prior estimates	-	23	(23)	-	48	9	57
Reserves, December 31, 2009	862	518	128	1,508	147	56	1,711

Natural Gas Reserves Reconciliation, Net of Royalties

Net Proved Reserves (bcf)	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 2007(1)	3,521	81	64	3,666
Extensions and discoveries	140	-	-	140
Improved recovery	52	(1)	6	57
Property purchases	77	-	-	77
Property disposals	(1)	-	-	(1)
Production	(449)	(4)	(4)	(457)
Economic revisions due to prices	(19)	(56)	6	(69)
Revisions of prior estimates	202	47	22	271
Reserves, December 31, 2008(1)	3,523	67	94	3,684
Extensions and discoveries	92	-	-	92
Improved recovery	11	-	-	11
SEC Reliable Technology (2)	-	-	-	-
Property purchases	15	-	-	15
Property disposals	(6)	-	-	(6)
Production	(443)	(4)	(6)	(453)
Economic revisions due to prices	(335)	12	(4)	(327)
Revisions of prior estimates	170	(8)	1	163
Reserves, December 31, 2009	3,027	67	85	3,179

Net Probable Reserves (bcf)(4)	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 2007(1)	1,081	32	24	1,137
Extensions and discoveries	42	-	-	42
Improved recovery	14	(2)	(6)	6
Property purchases	16	-	-	16
Property disposals	(5)	-	-	(5)
Production	-	-	-	-
Economic revisions due to prices	(8)	(7)	2	(13)
Revisions of prior estimates	(44)	4	17	(23)
Reserves, December 31, 2008(1)	1,096	27	37	1,160
Extensions and discoveries	19	-	-	19
Improved recovery	2	-	-	2
SEC Reliable Technology (2)	-	-	-	-
Property purchases	4	-	-	4
Property disposals	(1)	-	-	(1)
Production	-	-	-	-
Economic revisions due to prices	(94)	(5)	(1)	(100)
Revisions of prior estimates	(61)	5	3	(53)
Reserves, December 31, 2009	965	27	39	1,031

1. Reserves evaluated prior to December 31, 2009 were evaluated based on year end prices and costs. Previous year totals do not include SCO reserves.
2. SEC Reliable Technology accounts for reserves volumes added due to the reserves rule changes to allow booking of undeveloped reserves beyond one spacing unit with supporting geoscience and engineering data. Canadian Natural uses the combination of seismic, well logs, core analysis, production history and analogies to support the booking of undeveloped reserves.
3. SEC Rule Transition accounts for the inclusion of Horizon SCO reserves volume additions as a result of oil sands mining being included as a crude oil and natural gas activity effective December 31, 2009. For continuity purposes, with respect to the transition from Industry Guide 7 into the SEC's Final Rule, the following table has been provided to illustrate the changes in the Company's Horizon SCO reserves for the 2009 year.

Horizon SCO Reserves	Net Proved (mmbbl)	Probable (mmbbl)
Reserves, December 31, 2008	1,946	998
Production	(18)	-
Economic revisions due to prices	(307)	(127)
Revisions of prior estimates	29	(9)
Reserves, December 31, 2009	1,650	862

4. Prior to December 31, 2009, probable reserve estimates were evaluated in accordance with the standards of COGEH.

Information on the Company's crude oil, NGLs and natural gas reserves is provided in accordance with United States FASB Topic 932 "Extractive Activities - Oil and Gas" in the Company's Form 40-F filed with the SEC and in the Company's 2009 Annual Report under "Supplementary Oil and Gas Information" on pages 81 to 87 and is incorporated herein by reference.

D. CRUDE OIL, NGLs, AND NATURAL GAS PRODUCTION

The Company's working interest share and net of royalty share of crude oil, NGLs and natural gas production for the last three financial years is summarized below:

	Year Ended December 31		
Daily Production, before royalties	2009	2008	2007
Crude oil and NGLs production, (bbl/d)			
North America - Conventional	234,523	243,826	246,779
North America – Oil sands Mining and Upgrading	50,250	-	-
North Sea	37,761	45,274	55,933
Offshore West Africa	32,929	26,567	28,520
	355,463	315,667	331,232
Natural gas production (mmcf/d)			
North America	1,287	1,472	1,643
North Sea	10	10	13
Offshore West Africa	18	13	12
	1,315	1,495	1,668
Total Production boe/d	574,730	564,845	609,206

	Year Ended December 31		
Daily Production, net of royalties	2009	2008	2007
Crude oil and NGLs production, (bbl/d)			
North America - Conventional	201,873	207,933	210,769
North America – Oil sands Mining and Upgrading	48,833	-	-
North Sea	37,683	45,182	55,825
Offshore West Africa	29,922	22,641	26,012
	318,311	275,756	292,606
Natural gas production (mmcf/d)			
North America	1,214	1,225	1,378
North Sea	10	10	13
Offshore West Africa	17	11	11
	1,241	1,246	1,402
Total Production boe/d	525,103	483,541	526,193

NETBACKS
INFORMATION BY QUARTER

	2009					2008				
	Q1	Q2	Q3	Q4	Year Ended	Q1	Q2	Q3	Q4	Year Ended
Average daily production volumes, before royalties										
Conventional Crude oil and NGLs (bbl/d)	326,633	306,073	292,363	296,257	305,213	327,217	319,077	306,970	309,570	315,667
SCO (bbl/d)	3,384	59,599	66,907	70,194	50,250	-	-	-	-	-
Natural gas (mmcf/d)	1,369	1,352	1,293	1,250	1,315	1,538	1,526	1,490	1,427	1,495
Product netbacks (1)										
Conventional Crude oil and NGLs ($/bbl)										
Sales price (2)	$41.25	$59.56	$62.90	$68.00	$57.68	$78.99	$103.70	$102.30	$45.81	$82.41
Royalties	3.98	7.27	7.89	7.96	6.73	8.70	14.82	14.17	4.49	10.48
Production expenses	15.02	16.59	16.71	15.45	15.92	14.81	16.39	17.61	16.33	16.26
Netback	$22.25	$35.70	$38.30	$44.59	$35.03	$55.48	$72.52	$70.52	$24.99	$55.67
SCO ($/bbl)										
Sales price (2)	$-	$65.40	$69.11	$76.33	$70.83	$-	$-	$-	$-	$-
Royalties	-	0.76	2.19	3.06	2.15	-	-	-	-	-
Production expenses		42.65	36.85	41.21	39.89	-	-	-	-	-
Netback	$-	$21.99	$30.07	$32.06	$28.79	$-	$-	$-	$-	$-
Natural gas ($/mcf)										
Sales price (2)	$5.46	$4.11	$3.80	$4.75	$4.53	$7.77	$9.89	$8.82	$7.03	$8.39
Royalties(3)	0.72	0.06	0.13	0.35	0.32	1.35	1.86	1.55	1.08	1.46
Production expenses	1.18	1.05	1.05	1.03	1.08	1.03	0.94	1.05	1.06	1.02
Netback	$3.56	$3.00	$2.62	$3.37	$3.13	$5.39	$7.09	$6.22	$4.89	$5.91
Conventional Crude oil and NGLs netbacks by type(1)										

Light/Medium/Pelican Lake/NGLs ($/bbl)										
Sales price (2)	$47.93	$60.87	$65.58	$70.82	$61.37	$89.68	$114.69	$107.33	$53.16	$90.88
Royalties	4.94	6.70	9.27	7.96	7.20	11.43	14.59	15.84	5.71	11.83
Production expenses	15.02	16.87	17.48	16.79	16.53	15.09	16.13	17.18	17.92	16.56
Netback	$27.97	$37.30	$38.83	$46.07	$37.64	$63.15	$83.97	$74.30	$29.53	$62.49
Primary and Thermal Heavy crude oil ($/bbl)										
Sales price (2)	$34.80	$58.14	$60.08	$64.73	$53.76	$67.46	$92.55	$97.20	$38.21	$73.62
Royalties	3.06	7.89	6.43	7.97	6.23	5.74	15.05	12.47	3.22	9.08
Production expenses	15.02	16.29	15.91	13.89	15.27	14.50	16.65	18.05	14.68	15.95
Netback	$16.72	$33.96	$37.74	$42.87	$32.26	$47.22	$60.85	$66.68	$20.31	$48.59

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.
(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

NETBACKS
INFORMATION BY QUARTER

	2007				
	Q1	Q2	Q3	Q4	Year Ended
Average daily production volumes, before royalties					
Conventional Crude oil and NGLs (bbl/d)	327,001	327,494	333,062	337,240	331,232
Natural gas (mmcf/d)	1,717	1,722	1,647	1,589	1,668
Product netbacks(1)					
Conventional Crude oil and NGLs ($/bbl)					
Sales price (2)	$51.71	$53.74	$58.10	$58.03	$55.45
Royalties	4.92	5.46	6.65	6.66	5.94
Production expenses	13.81	15.01	13.13	11.53	13.34
Netback	$32.98	$33.27	$38.32	$39.84	$36.17
Natural gas ($/mcf)					
Sales price (2)	$7.74	$7.44	$5.87	$6.28	$6.85
Royalties	1.48	1.10	0.89	0.94	1.11
Production expenses	0.97	0.89	0.88	0.91	0.91
Netback	$5.29	$5.45	$4.10	$4.43	$4.83
Conventional Crude oil and NGLs netbacks by type(1)					
Light/Medium/Pelican Lake/NGLs ($/bbl)					
Sales price (2)	$60.19	$64.10	$67.34	$72.62	$65.99
Royalties	4.89	5.87	7.24	8.34	6.57
Production expenses	13.85	14.91	14.40	12.64	13.95
Netback	$41.45	$43.32	$45.70	$51.64	$45.47
Primary and Thermal Heavy crude oil ($/bbl)					
Sales price (2)	$41.24	$41.85	$48.10	$43.06	$43.66
Royalties	4.96	4.98	6.00	4.95	5.23
Production expenses	13.76	15.12	11.75	10.38	12.66
Netback	$22.52	$21.75	$30.35	$27.73	$25.77

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

	2009					2008				
	Q1	Q2	Q3	Q4	Year Ended	Q1	Q2	Q3	Q4	Year Ended
SEGMENTED										
North America product netbacks(1)										
Light/Medium/Pelican Lake/NGLs ($/bbl)										
Sales price (2)	$ 42.39	$57.67	$60.06	$65.80	$56.38	$82.25	$107.38	$102.17	$44.21	$84.00
Royalties	7.37	10.49	12.75	13.21	10.93	16.40	21.68	21.29	8.80	17.20
Production expenses	13.80	13.54	14.00	12.67	13.51	12.80	13.32	13.17	13.68	13.24
Netback	$ 21.22	$33.64	$33.31	$39.92	$31.94	$53.05	$72.38	$67.70	$21.73	$53.72
Primary and Thermal Heavy crude oil ($/bbl)										
Sales price (2)	$ 34.80	$58.14	$60.08	$64.73	$53.76	$67.46	$92.55	$97.20	$38.21	$73.62
Royalties	3.06	7.89	6.43	7.97	6.23	5.74	15.05	12.47	3.22	9.08
Production expenses	15.02	16.29	15.91	13.89	15.27	14.50	16.65	18.05	14.68	15.95
Netback	$ 16.72	$33.96	$37.74	$42.87	$32.26	$47.22	$60.85	$66.68	$20.31	$48.59
SCO ($/bbl)										
Sales price (2)	$ -	$65.40	$69.11	$76.33	$70.83	$-	$-	$-	$-	$-
Royalties	-	0.76	2.19	3.06	2.15	-	-	-	-	-
Production expenses	-	42.65	36.85	41.21	39.89	-	-	-	-	-
Netback	$ -	$21.99	$30.07	$32.06	$28.79	$-	$-	$-	$-	$-
Natural gas ($/mcf)										
Sales price (2)	$ 5.46	$4.06	$3.76	$4.75	$4.51	$7.74	$9.89	$8.76	$6.94	$8.41
Royalties(3)	0.73	0.05	0.12	0.35	0.32	1.36	1.88	1.55	1.09	1.47
Production expenses	1.17	1.04	1.04	1.01	1.07	1.01	0.98	1.03	1.04	1.00
Netback	$ 3.56	$2.97	$2.60	$3.39	$3.12	$5.37	$7.08	$6.18	$4.81	$5.88

North Sea product netbacks(1)										
Light crude oil ($/bbl)										
Sales price (2)	$ 54.67	$65.52	$75.91	$78.89	$68.84	$99.01	$129.57	$109.82	$63.07	$100.31
Royalties	0.13	0.11	0.16	0.15	0.14	0.91	0.27	0.24	0.12	0.21
Production expenses	22.39	27.36	31.30	27.03	26.98	22.35	25.61	29.21	28.77	26.29
Netback	$ 32.15	$38.05	$44.45	$51.71	$41.72	$76.47	$103.69	$80.37	$34.18	$73.81
Natural Gas ($/mcf)										
Sales price (2)	$ 4.28	$3.84	$5.70	$4.94	$4.66	$3.30	$4.27	$3.65	$5.19	$4.09
Royalties						-	-	-	-	-
Production expenses	1.86	1.62	1.57	3.23	2.16	2.33	2.68	3.09	1.96	2.51
Netback	$ 2.42	$2.22	$4.13	$1.71	$2.50	$0.97	$1.59	$0.56	$3.23	$1.58
Offshore West Africa product netbacks(1)										
Light crude oil ($/bbl)										
Sales price (2)	$ 54.27	$63.00	$70.05	$72.88	$65.27	$96.31	$114.56	$125.71	$65.80	$97.96
Royalties	3.73	5.82	8.94	5.24	5.79	17.43	14.49	26.90	4.71	14.81
Production expenses	11.39	10.45	13.35	15.26	12.83	8.03	9.79	7.74	14.47	10.29
Netback	$ 39.15	$46.73	$47.76	$52.38	$46.65	$70.85	$90.28	$91.07	$46.62	$72.86
Natural Gas ($/mcf)										
Sales price (2)	$ 6.68	$7.34	$5.72	$5.04	$6.11	$7.89	$8.97	$11.18	$12.54	$10.03
Royalties	0.46	0.63	0.74	0.27	0.53	1.43	1.13	2.24	1.26	1.52
Production expenses	1.70	1.36	1.37	0.70	1.23	1.25	1.27	1.58	2.51	1.61
Netback	$ 4.52	$5.35	$3.61	$4.07	$4.35	$5.21	$6.57	$7.36	$8.77	$6.90

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.
(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

	2007				
	Q1	Q2	Q3	Q4	Year Ended
SEGMENTED					
North America product netbacks(1)					
Light/Medium/Pelican Lake/NGLs ($/bbl)					
Sales price (2)	$54.13	$56.06	$60.26	$63.94	$58.66
Royalties	8.84	9.22	11.55	12.56	10.57
Production expense	11.74	12.11	11.58	10.82	11.56
Netback	$33.55	$34.73	$37.13	$40.56	$36.53
Primary and Thermal Heavy crude oil ($/bbl)					
Sales price (2)	$41.24	$41.85	$48.10	$43.06	$43.66
Royalties	4.96	4.98	6.00	4.95	5.23
Production expense	13.76	15.12	11.75	10.38	12.66
Netback	$22.52	$21.75	$30.35	$27.73	$25.77
Natural gas ($/mcf)					
Sales price (2)	$7.79	$7.47	$5.88	$6.31	$6.87
Royalties	1.50	1.11	0.90	0.95	1.12
Production expense	0.95	0.87	0.87	0.90	0.90
Netback	$5.34	$5.49	$4.11	$4.46	$4.85
North Sea product netbacks(1)					
Light crude oil ($/bbl)					
Sales price (2)	$68.83	$73.18	$77.55	$83.44	$74.99
Royalties	0.13	0.13	0.14	0.19	0.14
Production expense	18.57	22.11	23.61	18.95	20.78
Netback	$50.13	$50.94	$53.80	$64.30	$54.07
Natural gas ($/mcf)					
Sales price (2)	$4.49	$3.92	$5.26	$3.62	$4.26
Royalties	-	-	-	-	-
Production expense	2.58	2.26	2.29	1.50	2.17
Netback	$1.91	$1.66	$2.97	$2.12	$2.09
Offshore West Africa product netbacks(1)					
Light crude oil ($/bbl)					
Sales price (2)	$58.60	$72.84	$70.52	$81.89	$71.68
Royalties	3.70	7.12	6.81	7.59	6.40
Production expense	8.93	7.98	7.00	9.32	8.32
Netback	$45.97	$57.74	$56.71	$64.98	$56.96
Natural gas ($/mcf)					
Sales price (2)	$5.97	$6.22	$5.31	$5.49	$5.68
Royalties	0.38	0.59	0.51	0.52	0.51
Production expense	1.48	1.10	1.39	1.89	1.48
Netback	$4.11	$4.53	$3.41	$3.08	$3.69

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

E. NET CAPITAL EXPENDITURES

Costs incurred by the Company in respect of its programs of acquisition and disposition, and exploration and development of crude oil and natural gas properties, are summarized in the following tables.

NET CAPITAL EXPENDITURES BY YEAR (1)

	Year Ended December 31	
($ millions)	2009	2008
Net property acquisitions (dispositions)	$6	$336
Land acquisition and retention	77	86
Seismic evaluations	73	107
Well drilling, completion and equipping	1,244	1,664
Production and related facilities	977	1,282
Total net reserve replacement expenditures	2,377	3,475
Oil Sands Mining and Upgrading		
Horizon Phase 1 construction costs	69	2,732
Horizon Phase 1 commissioning and other costs	202	364
Horizon Phase 2/3 costs	104	336
Capitalized interest, stock-based compensation and other	98	480
Sustaining Capital	80	-
Total Oil Sands Mining and Upgrading (2)	553	3,912
Midstream	6	9
Abandonments (3)	48	38
Head office	13	17
Total net capital expenditures	$2,997	$7,451

NET CAPITAL EXPENDITURES BY QUARTER (1)

	2009 Three Months Ended			
($ millions)	Mar 31	Jun 30	Sep 30	Dec 31
Net property acquisitions (dispositions)	$27	(2)	(30)	11
Land acquisition and retention	13	18	18	28
Seismic evaluation	28	11	21	13
Well drilling, completion and equipping	498	194	261	291
Production and related facilities	290	230	235	222
Total net reserve replacement expenditures	856	451	505	565
Oil Sands Mining and Upgrading				
Horizon Phase 1 construction costs	128	(59)	-	-
Horizon Phase 1 commissioning and other costs	156	46	-	-
Horizon Phase 2/3 costs	19	22	21	42
Capitalized interest, stock-based compensation and other	79	(4)	11	12
Sustaining Capital	-	4	23	53
Total Oil Sands Mining and Upgrading (2)	382	9	55	107
Midstream	5	-	-	1
Abandonments (3)	9	10	12	17
Head office	4	3	2	4
Total net capital expenditures	$1,256	473	574	694

NET CAPITAL EXPENDITURES BY QUARTER (1)

	2008 Three Months Ended			
($ millions)	Mar 31	Jun 30	Sep 30	Dec 31
Net property acquisitions (dispositions)	$(8)	$263	$47	$34
Land acquisition and retention	12	24	32	18
Seismic evaluation	27	18	40	22
Well drilling, completion and equipping	452	286	421	505
Production and related facilities	319	270	311	382
Total net reserve replacement expenditures	802	861	851	961
Oil Sands Mining and Upgrading				
Horizon Phase 1 construction costs	665	875	635	557
Horizon Phase 1 commissioning and other costs	91	48	111	115
Horizon Phase 2/3 costs	77	82	83	94
Capitalized interest, stock-based compensation and other	109	247	46	78
Sustaining Capital	-	-	-	-
Total Oil Sands Mining and Upgrading (2)	941	1,252	875	844
Midstream	1	3	2	3
Abandonments (3)	6	7	10	15
Head office	3	4	6	4
Total net capital expenditures	$1,753	$2,127	$1,744	$1,827

(1) Net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.
(2) Net capital expenditures for the Oil Sands Mining and Upgrading assets also include the impact of intersegment eliminations.
(3) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

F. DEVELOPED AND UNDEVELOPED ACREAGE

The following table summarizes the Company’s working interest holdings in core region developed and undeveloped acreage as at December 31, 2009:

(thousands)	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
North America						
Alberta	6,255	5,003	9,238	7,901	15,493	12,904
British Columbia	1,485	1,125	2,814	2,046	4,299	3,171
Saskatchewan	739	554	803	687	1,542	1,241
Manitoba	7	6	17	17	24	23
North Sea						
United Kingdom	68	57	184	150	252	207
Offshore West Africa						
Côte d’Ivoire	10	6	92	54	102	60
Gabon	2	2	150	138	152	140
Total	8,566	6,753	13,298	10,993	21,864	17,746

SELECTED FINANCIAL INFORMATION

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

($ millions, except per common share information)	Year Ended Dec 31 2009	2008
Revenues, before royalties	$11,078	$16,173
Net earnings	$1,580	$4,985
Per common share - basic and diluted	$2.92	$9.22
Adjusted net earnings from operations (1)	$2,689	$3,492
Per common share - basic and diluted	$4.96	$6.46
Cash flow from operations (1)	$6,090	$6,969
Per common share - basic and diluted	$11.24	$12.89
Total assets	$41,024	$42,650
Total long-term liabilities	$19,193	$20,856

(1) These non-GAAP measures are reconciled to net earnings as determined in accordance with Canadian GAAP in the “Financial Highlights” section of the Company’s MD&A which is incorporated by reference into this document.

($ millions, except per common share information)	2009 Three Months Ended Mar 31	Jun 30	Sep 30	Dec 31
Revenues, before royalties	$ 2,186	2,750	2,823	3,319
Net earnings (loss)	$ 305	162	658	455
Per common share - basic and diluted	$ 0.56	0.30	1.21	0.85

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

CAPITAL STRUCTURE

Common Shares

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

Preferred Shares

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

Credit Ratings

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

Canadian Natural's senior unsecured debt securities are rated "Baa2" with a stable outlook by Moody's Investor's Service, Inc. ("Moody's"), "BBB" by Standard & Poor's Corporation ("S&P") and "BBB (high)" with a stable trend by DBRS Limit ("DBRS"). S&P assigns a rating outlook to Canadian Natural and not to individual debt instruments. S&P has assigned a stable outlook to Canadian Natural. Credit ratings are intended to provide investors with an independent measure of credit quality of any issue of securities.

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. A rating of Baa2 by Moody's is within the fourth highest of nine categories and is assigned to debt securities which are considered medium-grade obligations, i.e., they are subject to moderate credit risk. Such securities may possess certain speculative characteristics. Moody's applies numerical modifiers 1, 2 and 3 in each generic rating classification from Aa through Caa in its corporate bond rating system. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the issue ranks in the lower end of its generic rating category. A Moody's rating outlook is an opinion regarding the likely direction of a rating over the medium term.

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

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

MARKET FOR CANADIAN NATURAL RESOURCES LIMITED SECURITIES

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

2009 Monthly Historical Trading on TSX

Month	High	Low	Close	Volume Traded
January	$57.20	41.06	43.89	51,057,171
February	$48.44	36.50	40.90	50,126,029
March	$53.50	35.85	48.91	72,570,396
April	$61.15	47.70	55.01	46,587,159
May	$65.69	55.27	64.71	45,089,003
June	$68.69	54.08	61.19	43,417,767
July	$66.19	52.71	64.76	37,118,226
August	$68.54	61.55	62.71	29,996,464
September	$76.91	60.65	72.30	44,597,734
October	$79.00	67.38	70.22	33,029,358
November	$73.15	66.51	70.47	35,763,690
December	$76.46	65.97	76.00	30,807,147

On March 3, 2010 the Company's Board of Directors approved a resolution to file with the Toronto Stock Exchange a Notice of Intention to purchase by way of normal course issuer bid up to 2.5% of its issued and outstanding common shares. Subject to acceptance by the TSX of the Notice of Intention, the purchases would be made through the facilities of the TSX and the NYSE.

Also on March 3, 2010, the Company announced its intention to subdivide the Company's common shares on a two for one basis, subject to shareholder approval. The proposal will be voted on at the Company's Annual and Special Meeting of Shareholders to be held on May 6, 2010.

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 April 2001.

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

	2009	2008	2007
Cash dividends declared per common share	$0.42	$0.40	$0.34

In March 2010, the Board of Directors approved a 43% increase in the 2009 quarterly dividend from $0.105 per common share to $0.15 per common share, effective with the April 1, 2010 payment.

TRANSFER AGENTS AND REGISTRAR

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

DIRECTORS AND OFFICERS

The names, municipalities of residence, offices held with the Company and principal occupations of the directors and officers of the Company are set forth below. Further detail on the Directors and Named Executive Officers are found in the Company's Information Circular dated March 17, 2010 incorporated by reference.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Catherine M. Best, FCA, ICD.D Calgary, Alberta Canada	Director (2)(4)(5) (age 56)	Corporate Director. Until May 2009, Interim Chief Financial Officer of Alberta Health Services which was formed in 2008 when the Alberta government consolidated all of the health regions of the province under one board. Executive Vice-President, Risk Management and Chief Financial Officer of the Calgary Health Region (fully integrated publicly funded health care system) from 2002 to 2008; has served continuously as a director of the Company since November 2003. Currently serving on the board of directors of Enbridge Income Fund and Superior Plus Income Fund. She is also a member of the Board of the Alberta Children's Hospital Foundation and serves as a volunteer member of the Audit Committee of the Calgary Exhibition and Stampede.
N. Murray Edwards Calgary/Banff, Alberta Canada	Vice-Chairman and Director (3) (age 50)	President, Edco Financial Holdings Ltd. (private management and consulting company). Has served continuously as a director of the Company since September 1988. Currently is Chairman and serving on the board of directors of Ensign Energy Services Inc. and Magellan Aerospace Corporation.
Honourable Gary A. Filmon, P.C., O.C., O.M. Winnipeg, Manitoba Canada	Director (1)(2) (age 67)	Consultant, The Exchange Group (business consulting firm). Has served continuously as a director of the Company since February 2006. Currently serving on the board of directors of MTS Allstream Inc., Arctic Glacier Income Trust, Exchange Income Corporation, Wellington West Capital Inc. and FWS Construction Inc. and serves as Chair of Canada's Security and Intelligence Review Committee.
Ambassador Gordon D. Giffin Atlanta, Georgia USA	Director (1)(2)(3) (age 60)	Senior Partner, McKenna Long & Aldridge LLP (law firm) since May 2001. Has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of Canadian National Railway Company, Canadian Imperial Bank of Commerce, Just Energy Corp., and Transalta Corporation.
John G. Langille		

Calgary, Alberta Canada	Vice-Chairman and Director (age 64)	Officer of the Company. Has served continuously as a director of the Company since June 1982.
Steve W. Laut Calgary, Alberta Canada	President and Director (age 52)	Officer of the Company. Has served continuously as a director of the Company since August 2006.
Keith A.J. MacPhail Calgary, Alberta Canada	Director (3)(5) (age 53)	Chairman and Chief Executive Officer, Bonavista Energy Trust (oil and gas energy trust) since November 1997 and Chairman, NuVista Energy Ltd. (an oil and gas exploration, development and production company) since July 2003. Has served continuously as a director of the Company since October 1993. Currently serving on the board of directors of Bonavista Energy Trust and NuVista Energy Ltd.

Allan P. Markin, O.C. Calgary, Alberta Canada	Chairman and Director (5) (age 64)	Chairman of the Company. Has served continuously as a director of the Company since January 1989.
Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C. Cap Pelé, New Brunswick Canada	Director (1)(4) (age 62)	Deputy Chair, TD Bank Financial Group (financial services). Counsel to Atlantic Canada law firm McInnes Cooper from 1998 to 2005, and most recently Canadian Ambassador to the United States from 2005 to 2006. He has served continuously as a director of the Company since August 2006. Currently serving on the board of directors of Brookfield Asset Management Inc.
James S. Palmer, C.M., A.O.E., Q.C. Calgary, Alberta Canada	Director (3)(4)(5) (age 81)	Chairman and a Partner of Burnet, Duckworth & Palmer LLP (law firm). Has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Magellan Aerospace Corporation and is Director Emeritus of Frontier Oil Corporation.
Dr. Eldon R. Smith, O.C., M.D. Calgary, Alberta Canada	Director (4)(5) (age 70)	President of Eldon R. Smith & Associates Ltd., (a private health care consulting company), and Emeritus Professor of Medicine and Former Dean, Faculty of Medicine, University of Calgary. Has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Intellipharmaceutics International Inc. and Aston Hill Financial.
David A. Tuer Calgary, Alberta Canada	Director (1)(2)(3) (age 60)	Vice-Chairman and Chief Executive Officer of Marble Point Energy Ltd. (private oil and gas exploration company); Chairman, Calgary Health Region from 2001 to 2008 and Executive Vice-Chairman BA Energy Inc. from April 2005 to February 2008 when it was acquired by its parent company Value Creations Inc. through a Plan of Arrangement and which until recently was engaged in the development, building and operations of a merchant heavy oil upgrader in Northern Alberta for the purpose of upgrading bitumen and heavy oil feedstock into high-quality crude oils. Prior thereto President, CEO and a director of Hawker Resources Inc. from January 2003 to March 2005. Has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of Daylight Resources Trust, Xtreme Coil Drilling Corp., Canadian Phoenix Resources and Altalink Management LLP., a private limited partnership.
Jeffrey J. Bergeson Calgary, Alberta	Vice-President, Exploitation West	Officer of the Company since May 2007; prior thereto Exploitation Manager of the Company.

Canada	(age 53)	
Corey B. Bieber Calgary, Alberta Canada	Vice-President, Finance and Investor Relations (age 46)	Officer of the Company since April 2005; prior thereto Director, Investor Relations of the Company from July 2002 to April 2005 and most recently Vice-President, Investor Relations April 2005 to February 2007.
Mary-Jo E. Case Calgary, Alberta Canada	Vice-President, Land (age 51)	Officer of the Company.
William R. Clapperton Calgary, Alberta Canada	Vice-President, Regulatory, Stakeholder and Environmental Affairs (age 47)	Officer of the Company.

James F. Corson Calgary, Alberta Canada	Vice-President, Human Resources, Horizon (age 59)	Officer of the Company since January 2007; prior thereto Vice-President, Human Resources of Qatar Petroleum Corp. from March 1997 to July 2005 and most recently Director Human Resources and Stakeholder Relations of the Company from July 2005 to 2007.
Réal M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 59)	Officer of the Company.
Randall S. Davis Calgary, Alberta Canada	Vice-President, Finance & Accounting (age 43)	Officer of the Company.
Réal J. H. Doucet Calgary, Alberta Canada	Senior Vice-President, Horizon Projects (age 57)	Officer of the Company.
Allan E. Frankiw Calgary, Alberta Canada	Vice-President, Production, Central (age 53)	Officer of the Company since March 2007; prior thereto Manager Midstream for Anadarko Canada Corporation from November 1998 to March 2005, Manager Facilities & Construction for Anadarko Canada Corporation from April 2005 to November 2006, and most recently Production Manager, Edson of the Company from November 2006 to March 2007.
Tim Hamilton Calgary, Alberta Canada	Vice-President, Developments (age 54)	Officer of the Company since February 2010; prior thereto Manager Production, Southern Alberta from 2000 to 2006, Manager Production, Southern Alberta, S.E. Saskatchewan and Manitoba 2006 to 2007, Manager Production, British Columbia South 2007 to September 2009 and most recently Manager Production, British Columbia from September 2009 to February 2010.
Peter J. Janson Calgary, Alberta Canada	Senior Vice-President, Horizon Operations (age 52)	Officer of the Company.
Terry Jocksch Calgary, Alberta Canada	Senior Vice-President, Thermal and International (age 42)	Officer of the Company since June 2009; prior thereto Exploitation Manager of the Company to April 2004, Vice-President Exploitation West April 2004 to May 2007, and most recently Managing Director, International May 2007 to June 2009.
Philip A. Keele Calgary, Alberta Canada	Vice-President, Mining, Horizon Oil Sands Project	Officer of the Company.

	(age 50)	
Allen M. Knight Calgary, Alberta Canada	Senior Vice-President, International & Corporate Development (age 60)	Officer of the Company.
Cameron S. Kramer Calgary, Alberta Canada	Senior Vice-President, North America Operations (age 42)	Officer of the Company.
Ronald K. Laing Calgary, Alberta Canada	Vice-President, Commercial Operations (age 40)	Officer of the Company since March 2009; prior thereto Manager, Commercial Operations of the Company from April 2004 to March 2009.

Reno G. Laseur Fort McMurray, Alberta Canada	Vice-President, Upgrading (age 54)	Officer of the Company since August 2008; prior thereto Operations Manager, Upgrading of the Company November 2002 to October 2007, and most recently Operations Director, Upgrading of the Company from October 2007 to August 2008.
Bruce E. McGrath Calgary, Alberta Canada	Corporate Secretary (age 60)	Officer of the Company.
Tim S. McKay Calgary, Alberta Canada	Chief Operating Officer (age 48)	Officer of the Company.
Paul Mendes Calgary, Alberta Canada	Vice-President Legal and General Counsel (age 44)	Officer of the Company since February 2010; prior thereto Manager, Legal Services, Horizon January 2005 to January 2007 and most recently Director, Legal Services Horizon from January 2007 to February 2010.
Leon Miura Calgary, Alberta Canada	Vice-President, Horizon Downstream Projects (age 55)	Officer of the Company.
S. John Parr Calgary, Alberta Canada	Vice-President, Production, East (age 48)	Officer of the Company.
David A. Payne Calgary, Alberta Canada	Vice-President, Exploitation, Central (age 48)	Officer of the Company.
William R. Peterson Calgary, Alberta Canada	Vice-President, Production, West (age 43)	Officer of the Company.
Douglas A. Proll Calgary, Alberta Canada	Chief Financial Officer and Senior Vice-President, Finance (age 59)	Officer of the Company.
Timothy G. Reed Calgary, Alberta Canada	Vice-President, Human Resources (age 53)	Officer of the Company since January 2007; prior thereto Manager, Human Resources of the Company 2000 to 2005 and most recently Director, Human Resources 2005 to January 2007.
Joy P. Romero Calgary, Alberta Canada	Vice President, Bitumen Production (age 53)	Officer of the Company since March 2008; prior thereto Director, Bitumen Production Process of the Company from September 2002 to March 2008.

Sheldon L. Schroeder Fort McMurray, Alberta Canada	Vice-President, Horizon Upstream Projects (age 42)	Officer of the Company.
Kendall W. Stagg Calgary, Alberta Canada	Vice-President, Exploration, West (age 48)	Officer of the Company.
Scott G. Stauth Calgary, Alberta Canada	Vice-President, Field Operations (age 52)	Officer of the Company since November 2006; prior thereto Manager, Eastern Field Operations of the Company from April 2003 to November 2006.
Lyle G. Stevens Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 55)	Officer of the Company.

Stephen C. Suche Calgary, Alberta Canada	Vice-President, Information and Corporate Services (age 50)	Officer of the Company since July 2006; prior thereto Manager Information and Corporate Services of the Company from January 2000 to July 2006.
Domenic Torriero Calgary, Alberta Canada	Vice-President, Exploration, Central (age 45)	Officer of the Company since November 2006; prior thereto Exploration Manager of the Company from March 2004 to November 2006.
Grant M. Williams Calgary, Alberta Canada	Vice-President, Exploration, East (age 52)	Officer of the Company since March 2007; prior thereto Manager, Exploration Heavy Oil of the Company from October 2003 to April 2007.
Jeffrey W. Wilson Calgary, Alberta Canada	Senior Vice-President, Exploration (age 57)	Officer of the Company.
Daryl G. Youck Calgary, Alberta Canada	Vice-President, Exploitation, East (age 41)	Officer of the Company since February 2008; prior thereto Manager, Exploitation of the Company from July 2002 to February 2008.
Lynn M. Zeidler Calgary, Alberta Canada	Vice-President, Horizon Operations and Project Services (age 53)	Officer of the Company.

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

All directors stand for election at each Annual General Meeting of Canadian Natural shareholders. All of the current directors were elected to the Board at the last annual general meeting of shareholders held on May 7, 2009.

As at December 31, 2009, the directors and officers of the Company, as a group, beneficially owned or controlled or directed, directly or indirectly, in the aggregate, approximately 4.2% of the total outstanding common shares (approximately 5.8% after the exercise of options held by them pursuant to the Company's stock option plan).

CONFLICTS OF INTEREST

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

AUDIT COMMITTEE INFORMATION

Audit Committee Members

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

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

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

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

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

Auditor Service Fees

The Audit Committee of the Board of Directors in 2009 approved specified audit and non-audit services to be performed by PricewaterhouseCoopers LLP (“PwC”). The services provided include: (i) the annual audit of the Corporation's consolidated financial statements and internal controls over financial reporting, reviews of the Corporation's quarterly unaudited consolidated financial statements, audits of certain of the Corporation's subsidiary companies' annual financial statements, assistance related to the Corporation's conversion to International Financial Reporting Standards, as well as other audit services provided in connection with statutory and regulatory filings; (ii) audit related services including debt covenant compliance and Crown Royalty Statements; (iii) tax related services related to expatriate personal tax and compliance as well as other corporate tax return matters; and (iv) non-audit services related to accessing resource materials through PwC’s accounting literature library.

Fees accrued to PwC are shown in the table below.

Auditor service	2009	2008
Audit fees	$2,710,100	$2,685,800
Audit related fees	154,300	156,300
Tax related fees	131,650	91,500
All other fees	9,500	9,500
	$3,005,550	$2,943,100

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

LEGAL PROCEEDINGS

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

MATERIAL CONTRACTS

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

INTERESTS OF EXPERTS

The Company's auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditors' report dated March 3, 2010 in respect of the Company's consolidated financial statements as at December 31, 2009 and December 31, 2008 with accompanying notes for each of the years in the three year period ended December 31, 2009 and the Company's internal control over financial reporting as at December 31, 2009. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules of the SEC.

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

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on the SEDAR website at www.sedar.com and on EDGAR at www.sec.gov

Additional information including Directors' and Executive Officers' remuneration and indebtedness, Director nominees standing for re-election, principal holders of the Company's securities, options to purchase the Company's securities and interest of insiders in material transactions is contained in the Company's Notice of Annual and Special Meeting and Information Circular dated March 17, 2010 in connection with the Annual and Special Meeting of Shareholders of Canadian Natural to be held on May 6, 2010 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, 2009 found on pages 20 to 51, 52 to 80 and 81 to 87 respectively, of the 2009 Annual Report to the Shareholders, which information is incorporated herein by reference.

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

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

SCHEDULE "A"
FORM 51-101F2

REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Report on Reserves Data

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

1. We have reviewed and evaluated the Corporation's reserves data as at December 31, 2009. The reserves data consist of the following:

(a)	(i)	both proved, and proved and probable crude oil, synthetic crude oil, NGLs and natural gas reserve quantities estimated as at December 31, 2009 using 12-month average prices and current costs;
	(ii)	the related future net revenue; and
	(iii)	the related standardized measure calculation for proved crude oil, synthetic crude oil, NGL and natural gas reserve quantities.
(b)	(i)	both proved, and proved and probable crude oil, synthetic crude oil, NGL and natural gas reserve quantities estimated as at December 31, 2009 using forecast prices and costs;
	(ii)	the related future net revenue.

2. The reserves data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society) with the necessary modifications to reflect definitions and standards under the U.S. Financial Accounting Standards Board policies (the "FASB Standards") and the legal requirements of the U.S. Securities and Exchange Commission ("SEC Requirements").

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions as outlined in the COGE Handbook, the FASB Standards and the SEC Requirements.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2009 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	Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate) ($millions Cdn) Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	Evaluation and review of the P&NG Reserves, February 8th, 2010	Canada and USA	$0	$37,994	$3,041	$41,035
Sproule Associates Limited	Evaluation and review of the P&NG Reserves, February 8th, 2010	United Kingdom and Offshore West Africa	$0	$10,053	$3,682	$13,735
GLJ Petroleum Consultants Limited	Evaluation of the oil sands mining reserves, March 2nd, 2010	Canada	$0	$23,064	$0	$23,064
Totals			$0	$71,111	$6,723	$77,834

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook as modified by the FASB Standards and SEC requirements. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

Executed as to our report referred to above:

Sproule Associates Limited, Calgary, Alberta, Canada, March 3, 2010

Original Signed By:

SIGNED “HARRY J. HELWERDA”
Harry J. Helwerda, P.Eng.,
Executive Vice-President

Original Signed By:

SIGNED “DOUG HO”
Doug Ho, P.Eng.
Vice-President, Unconventional

Original Signed By:

SIGNED: “R. KEITH MACLEOD”
R. Keith MacLeod, P.Eng.
President

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 3, 2010
Original Signed By:

SIGNED: “JAMES H. WILLMON”
James H. Willmon, P.Eng.
Vice-President

SCHEDULE "B"

REPORT OF
MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE

Report of Management and Directors on Reserves Data and Other Information

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

(a) (i) both proved, and proved and probable crude oil, synthetic crude oil, NGLs and natural gas reserve quantities estimated as at December 31, 2009 using 12-month average prices and current costs;
(ii) the related future net revenue; and
(iii) the related standardized measure calculation for proved crude oil, synthetic crude oil, NGL and natural gas reserve quantities.

(b) (i) both proved, and proved and probable crude oil, synthetic crude oil, NGL and natural gas reserve quantities estimated as at December 31, 2009 using forecast prices and costs;
(ii) the related future net revenue.

Sproule Associates Limited and GLJ Petroleum Consultants Ltd., both independent qualified reserves evaluators, have evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The reserves committee (the "Reserves Committee") of the board of directors (the "Board of Directors") of the Corporation has:

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

(b) met with each of the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation and in the event of a proposal to change the independent qualified reserves evaluators, to inquire whether there had been disputes between the previous independent qualified reserves evaluators and management; and

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

The Reserves Committee of the Board of Directors has reviewed the Corporation’s procedures for assembling and reporting other information associated with oil, gas and surface mineable oil sands activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of reserves data and other oil, gas and surface mineable oil sands information contained in the Company’s Annual Information Form to which this report is attached as Schedule “B”;

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

(c) the content and filing of this report.

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

Original Signed By:

SIGNED: “STEVE W. LAUT”
Steve W. Laut
President

Original Signed By:

SIGNED: “DOUGLAS A. PROLL”
Douglas A. Proll
Chief Financial Officer and Senior Vice President, Finance

Original Signed By:

SIGNED: “DAVID A. TUER”
David A. Tuer
Independent Director and Chair of the Reserves Committee

Original Signed By:

SIGNED: “JAMES S. PALMER”
James S. Palmer
Independent Director and Member of the Reserves Committee

Dated this 3rd day of March, 2010
Calgary, Alberta

SCHEDULE “C”

CANADIAN NATURAL RESOURCES LIMITED
(the “Corporation”)

Charter of the Audit Committee of the Board of Directors

I. Audit Committee Purpose

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

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

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

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

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

5. monitor the performance of the internal audit function;

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

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

II. Audit Committee Composition, Procedures and Organization

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

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

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

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

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

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

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

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

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

III. Audit Committee Duties and Responsibilities

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

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

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

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

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

e.

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

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

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

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

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

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

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

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

(i) contents of their report, including :

(a) all critical accounting policies and practices used;

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

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

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

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

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

(v) internal resources used;

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

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

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

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

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

h.

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

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

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

b. to review the internal audit plan; and

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

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

a. to review the appropriateness and effectiveness of the Corporation's policies and business practices which impact on the financial integrity of the Corporation, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting (including financial reporting) and risk management;

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

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

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

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

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

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

d. to review management's report on the appropriateness of the policies and procedures used in the preparation of the Corporation's consolidated financial statements and other required disclosure documents and consider recommendations for any material change to such policies;

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

f. to establish procedures for:

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

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

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

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

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

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

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

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 Amendment to be signed on its behalf by the undersigned, thereto duly authorized.

CANADIAN NATURAL RESOURCES LIMITED

By:	SIGNED "STEVE W. LAUT"
	Name: Steve W. Laut
	Title: President
	Date: April 29, 2010

The following documents have been filed as part of this Amendment to the Annual Report on Form 40-F as Exhibits hereto:

EXHIBIT INDEX

Exhibit No.	Description
1.*	Supplementary Oil & Gas Information for the fiscal year ended December 31, 2009.
2.	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.
3.	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.
4.*	Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
5.*	Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
6.*	Consent of PricewaterhouseCoopers LLP, independent chartered accountants.
7.*	Consent of Sproule Associates Limited, independent petroleum engineering consultants.
8.*	Consent of GLJ Petroleum Consultants Ltd., independent petroleum engineering consultants.

* Previously filed.