

CANADIAN NATURAL RESOURCES LTD
Form 40-F
March 25, 2014

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

FORM 40-F

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

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

For the fiscal year ended December 31, 2013

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:

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.

1,087,321,664 Common Shares outstanding as of December 31, 2013

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 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 _____

This Annual Report on Form 40-F shall be incorporated by reference into, or as an exhibit to, as applicable, the Registrant's Registration Statement on Form F-10 (File No. 333-191876) under the Securities Act of 1933 as amended.

All dollar amounts in this Annual Report on Form 40-F are expressed in Canadian dollars. As of March 21, 2014, the noon buying rate for Canadian Dollars as expressed by the Federal Reserve Bank of New York was US\$1.00 equals C\$1.1191.

Principal Documents

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

A. Annual Information Form

Annual Information Form of Canadian Natural Resources Limited ("Canadian Natural") for the year ended December 31, 2013.

B. Audited Annual Financial Statements

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2013 and 2012, including the auditor's report with respect thereto.

C. Management's Discussion and Analysis

Canadian Natural's Management's Discussion and Analysis for the year ended December 31, 2013.

Supplementary Oil & Gas Information

For Canadian Natural's Supplementary Oil & Gas Information for the year ended December 31, 2013, see Exhibit 1 to this Annual Report on Form 40-F.

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2013

March 24, 2014

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DEFINITIONS AND ABBREVIATIONS

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

ACC	Anadarko Canada Corporation
API	Specific gravity measured in degrees on the American Petroleum Institute scale.
ARO	Asset retirement obligations
bbbl	barrels
bbbl/d	barrels per day
Bcf	billion cubic feet
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
“Canadian Natural Resources Limited”, “Canadian Natural”, “Company”, “Corporation”	Canadian Natural Resources Limited and includes, where applicable, reference to subsidiaries of and partnership interests held by Canadian Natural Resources Limited and its subsidiaries.
CBM	Coal Bed Methane
CO ₂	Carbon dioxide
CO ₂ e	Carbon dioxide equivalents
Crude oil, NGLs and natural gas	The Company’s light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), synthetic crude oil, natural gas and natural gas liquids reserves.
CSS	Cyclic Steam Simulation
development well	Well drilled inside the established limits of an oil or gas reservoir or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
dry well	Well that proves to be incapable of producing either crude oil or natural gas in sufficient quantities to justify completion.
EOR	Enhanced Oil Recovery
exploratory well	Well that is not a development well, a service well, or a stratigraphic test well.
extension well	Well that is drilled to test if a known reservoir extends beyond what had previously been believed to be the outer reservoir perimeter.
FPSO	Floating Production, Storage and Offloading vessel
GHG	Greenhouse gas
gross acres	Total number of acres in which the Company has a working interest.
gross wells	Total number of wells in which the Company has a working interest.
Horizon	Horizon Oil Sands
IFRS	International Financial Reporting Standards
Mbbl	thousand barrels
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MD&A	Management’s Discussion and Analysis
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day

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MMcfe	millions of cubic feet equivalent
MM\$	million Canadian dollars
NGLs	Natural gas liquids
net acres	Gross acres multiplied by the percentage working interest therein owned.
net asset value	Net present value of the future net revenue before income tax of the Company's total proved plus probable crude oil, NGLs and natural gas reserves prepared using forecast prices and costs discounted at 10%, plus the estimated market value of core unproved property, less net debt. Future development costs and associated material well abandonment costs have been applied against the future net revenue before income tax.
net wells	Gross wells multiplied by the percentage working interest therein owned by the Company.
NYSE	New York Stock Exchange
productive well	Exploratory, development or extension well that is not dry.
proved property	Property or part of a property to which reserves have been specifically attributed.
PRT	Petroleum Revenue Tax
SAGD	Steam-Assisted Gravity Drainage
SCO	Synthetic crude oil
SEC	United States Securities and Exchange Commission
service well	Well drilled or completed for the purpose of supporting production in an existing field and drilled for the specific purposes of gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.
stratigraphic test well	Drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition and ordinarily drilled without the intention of being completed for hydrocarbon production.
TSX	Toronto Stock Exchange
UK	United Kingdom
unproved property	Property or part of a property to which no reserves have been specifically attributed.
US	United States
working interest	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	West Texas Intermediate at Cushing, Oklahoma

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (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”, “potential”, “predict”, “should”, “will”, “objective”, “project”, “forecast”, “goal”, “guidance”, “outlook”, “effort”, “seeks”, “intends”, or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes and costs, royalties, operating costs, capital expenditures, income tax expenses, and other guidance provided throughout this Annual Information Form (“AIF”) constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansions, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the construction and future operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or SCO that the Company may be reliant upon to transport its products to market 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 as 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 and proved plus probable crude oil, NGLs 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 and uncertainties 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 capital programs; the Company’s and its subsidiaries’ ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of 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 and in mining, extracting or upgrading the Company’s bitumen products; 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, NGLs and natural gas not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses. The Company's operations have been, and 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. For additional information refer to the "Risks Factors" section of this AIF.

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Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this AIF 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, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management's estimates or opinions change.

Special Note Regarding Currency, Financial Information, Production and Reserves

In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data are 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 conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6Mcf:1bbl conversion ratio may be misleading as an indication of value.

This AIF, the comparative Consolidated Financial Statements and the Company's Management's Discussion and Analysis for the most recently completed fiscal year ended December 31, 2013, herein incorporated by reference, have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board.

For the year ended December 31, 2013, the Company retained Independent Qualified Reserves Evaluators ("Evaluators"), Sproule Associates Limited and Sproule International Limited (together as "Sproule") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved and proved plus probable reserves with an effective date of December 31, 2013 and a preparation date of February 3, 2014. Sproule evaluated the North America and International light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), natural gas and NGLs reserves. GLJ evaluated the Horizon SCO reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 "Extractive Activities - Oil and Gas" in the Company's Form 40-F filed with the SEC in the "Supplementary Oil and Gas Information" section of the Company's Annual Report on pages 92 to 99 which is incorporated herein by reference.

Special Note Regarding Non GAAP Financial Measures

This AIF includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, adjusted cash production costs, and net asset value. These financial measures are not defined by IFRS 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 IFRS, 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 IFRS in the "Net Earnings and Cash Flow from Operations" section of the Company's MD&A which is incorporated by reference into this document. The derivation of adjusted cash production costs is included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of the Company's MD&A which is incorporated by reference into this document.

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CORPORATE STRUCTURE

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.

The Company has amalgamated pursuant to the Business Corporations Act (Alberta) under the name Canadian Natural Resources Limited with the following:

October 1, 2000 - Ranger Oil Limited (“Ranger”)

January 1, 2003 - Rio Alto Exploration Ltd. (“RAX”)

January 1, 2004 - CanNat Resources Inc.

January 1, 2007 - ACC-CNR Resources Corporation

January 1, 2008 - Ranger Oil (International) Ltd.; 764968 Alberta Inc., CNR International (Norway) Limited, Renata Resources Inc.

January 1, 2012 - Aspect Energy Ltd., Creo Energy Ltd., 1585024 Alberta Ltd.

January 1, 2014 - Barrick Energy Inc.

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

Subsidiary	Jurisdiction of Incorporation	% Ownership
CanNat Energy Inc.	Delaware	100
CNR (ECHO) Resources Inc.	Alberta	100
CNR (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
CNR International (South Africa) Limited	Alberta	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 wholly owned partnerships.

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GENERAL DEVELOPMENT OF THE BUSINESS

2011

During 2011, the Company issued US\$500 million of 1.45% unsecured notes due November 2014, and US\$500 million of 3.45% unsecured notes due November 2021. Net proceeds were used to repay bank indebtedness.

The Company completed a number of transactions in the normal course to acquire and dispose of interests in crude oil and natural gas properties for an aggregate net expenditure of \$1 billion. 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.

2012

During 2012, the Company entered into a 20 year transportation agreement to ship 75,000 bbl/d of crude oil on the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia. The regulatory approval process began in 2013 with a planned in-service date in 2017.

During 2012, the Company issued C\$500 million of 3.05% medium-term notes due June 2019. Net proceeds from the sale were used to repay bank indebtedness and for general corporate purposes.

The Company has a 20 year transportation agreement to ship 120,000 bbl/d of heavy crude oil on the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast. In addition, the Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy crude oil to a major US refiner. The construction of the Keystone XL Pipeline is dependent on a Presidential Permit.

The Company completed a number of transactions in the normal course to acquire and dispose of interests in crude oil and natural gas properties for an aggregate net expenditure of \$144 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.

2013

In 2011, the Company announced that it had entered into a partnership agreement with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of a bitumen upgrader and refinery ("the Project") near Redwater, Alberta. In addition, the partnership has entered into processing agreements that target to process bitumen for the Company of 12,500 bbl/d and bitumen for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, of 37,500 bbl/d under a 30 year fee-for-service tolling agreement under the Bitumen Royalty In Kind initiative. In 2012, the Project was sanctioned by the Board of Directors of each partner of the North West Redwater Partnership ("Redwater Partnership"), and the associated target toll amounts were accepted by Redwater Partnership, the Company and the APMC. In December 2013, Redwater Partnership, the Company and APMC agreed in principle to amend certain terms of the processing agreements. In conjunction with these amendments, the Company, along with APMC, each committed to provide additional funding up to \$350 million to attain Project completion based on the revised Project cost estimate of approximately \$8,500 million. The additional funding is to be in the form of subordinated debt bearing interest at prime plus 6%, which is anticipated to form part of the equity toll. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

During 2013, the Company discovered bitumen emulsion at surface in areas of the Primrose field. The Company's view is that the cause of the occurrence is mechanical in nature and is working collaboratively with the regulators in the causation review and remediation plans. The Company's near term steaming plan at the Primrose field has been modified, with steaming being restricted in certain areas until the causation review with the regulators is complete.

During 2013, the Company acquired all the issued and outstanding shares of Barrick Energy Inc. and 1729580 Alberta Ltd., subsidiaries of Barrick Gold Corporation for approximately \$173 million. Production, before royalties, from the working interest acquired by the Company is approximately 4,200 bbl/d of light crude oil and NGLs and approximately 4.4 MMcf/d of natural gas.

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During 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for a net cash consideration of US\$255 million, including a recovery of US\$14 million of past incurred costs. In the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US\$450 million for a commercial crude oil discovery and US\$120 million for a commercial natural gas discovery.

During 2013, the Company entered into a 20 year transportation agreement to ship 80,000 bbl/d of crude oil on the proposed Energy East pipeline originating at Hardisty, Alberta with delivery points in Quebec City, Quebec and Saint John, New Brunswick. This pipeline is subject to regulatory approval.

During 2013, the Company issued C\$500 million of 2.89% medium-term notes due August 2020 which were sold to investors in Canada. Net proceeds from the sale were used to repay bank indebtedness and for general corporate purposes.

The Company completed a number of transactions in the normal course to acquire and dispose of interests in crude oil and natural gas properties for an aggregate net expenditure of \$246 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.

2014

In 2014, the Company entered into an agreement to acquire certain producing Canadian crude oil and natural gas properties, together with undeveloped land, for total cash consideration of approximately \$3,125 million, based on an effective date of January 1, 2014, with a targeted closing date of April 1, 2014. In connection with the agreement, the Company negotiated an additional \$1,000 million unsecured bank credit facility with a two-year maturity and with terms similar to the Company's current syndicated credit facilities, which is available upon closing.

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. The Company's principal core regions of operations are western Canada, the UK sector of the North Sea and Offshore 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, NGLs 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, 2013, the Company had the following full time equivalent permanent employees:

North America, Exploration and Production	3,875
North America, Oil Sands Mining and Upgrading	2,336
North Sea	360
Offshore Africa	50
Total Company	6,621

Operational discipline, safe, effective and efficient operations as well as cost control are fundamental to the Company. By consistently managing costs throughout all industry cycles, the Company believes it will achieve continued growth. Effective and efficient operations and cost control are attained by developing area knowledge and by maintaining high working interests and operator status in its properties. The Company has grown through a combination of internal growth and strategic acquisitions. Acquisitions are made with a view to either enter new core regions or increase 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 and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), SCO and NGLs. The Company's large diversified project portfolio enables the effective allocation of capital to higher return opportunities, which together provide complementary infrastructure and balance throughout the business cycle. Natural gas is the largest single commodity sold accounting for 29% of 2013 production. Virtually all of the Company's natural gas and NGLs production is located in the Canadian provinces of Alberta, British Columbia and

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Saskatchewan and is marketed in Canada and the United States. Light and medium crude oil and NGLs, representing 15% of 2013 production, is located in the Company's North Sea and Offshore Africa properties, and in the provinces of Alberta, British Columbia and Saskatchewan. Primary heavy crude oil accounting for 20% of 2013 production, Pelican Lake heavy crude oil accounting for 7% of 2013 production, and our bitumen (thermal oil) accounting for 14% of 2013 production are in the provinces of Alberta and Saskatchewan. SCO from our oil sands mining operations in Northern Alberta accounted for approximately 15% of 2013 production. Midstream assets, primarily comprised two operated and one non operated pipeline systems, an electricity cogeneration facility provide cost effective infrastructure supporting the heavy crude oil and bitumen operations. The Company's Midstream assets also include a 50% interest in the North West Redwater Partnership ("Redwater Partnership").

A. ENVIRONMENTAL MATTERS

The Company strives to carry out its activities in compliance with applicable regional, national and international regulations and industry standards. Environmental specialists in Canada and the UK track performance to numerous environmental performance indicators, 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's associated environmental risk management strategies focus on working with legislators and regulators to ensure that any new or revised policies, legislation or regulations properly reflect a balanced approach to sustainable development. Specific measures in response to existing or new legislation include a focus on the Company's energy efficiency, air emissions management, released water quality, reduced fresh water use and the minimization of the impact on the landscape. Training and due diligence for operators and contractors are key to the effectiveness of the Company's environmental management programs and the prevention of incidents. 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 operations while meeting regulatory requirements, regional management frameworks, industry operating standards and guidelines, and internal corporate standards. The Company's proactive program includes: an internal environmental compliance audit and inspection program of the Company's operating facilities; a suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an effective surface reclamation program; a due diligence program related to groundwater monitoring; an active program related to preventing and reclaiming spill sites; a solution gas conservation program; a program to replace the majority of fresh water for steaming with brackish water; water 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 operated facilities; continued evaluation of new technologies to reduce environmental impacts and support for Canada's Oil Sands Innovation Alliance ("COSIA"); CO2 reduction programs including the injection of CO2 into tailings and for use in EOR; a program in place related to progressive reclamation and tailings management for the Horizon Oil Sands facility; and participation and support for the Joint Implementation Plan for Oil Sands Monitoring. 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. The Company has also adopted the Hydraulic Fracturing Operating Practices that were developed by the

Canadian Association of Petroleum Producers (“CAPP”). In 2013, Canadian Natural continued its environmental liability reduction program with the abandonment of 460 inactive wells. In addition, reclamation was initiated at many of these sites with the eventual goal of reclamation certification. In 2013 the Company received 259 reclamation certificates representing 490 hectares of land. Further, decommissioning of inactive facilities and cleanup of active facilities was conducted to address environmental liabilities at operating assets. The Company participates in both the Canadian federal and provincial regulated GHG emissions reporting programs and continues to quantify annual GHG emissions for internal reporting purposes. The Company has participated in the CAPP Responsible Canadian Energy Program since 2000. The Company continues to invest in people, proven and new technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner.

The Company, through CAPP, is working with Canadian legislators and regulators as they develop and implement new GHG emissions laws and regulations. Internally, the Company is pursuing an integrated emissions reduction strategy, to ensure it is able to comply with existing and future emissions reduction requirements, for both GHGs and air pollutants (such as sulphur dioxide and oxides of nitrogen). The Company continues to develop strategies that will enable it to deal with the risks

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and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties, such as COSIA and Carbon Management Canada (“CMC”), to ensure that new policies encourage technological innovation, energy efficiency, and 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. The Company 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, fuel and solution gas conservation programs. In 2013 the Company completed approximately 798 gas conservation projects in its primary heavy crude oil operations, resulting in a reduction of 3.3 million tonnes/year of CO₂e. Over the past five years the Company has spent over \$75 million in its primary heavy crude oil and in situ oil sands operations to conserve the equivalent of over 13.5 million tonnes of CO₂e. The Company also monitors the performance of its compressor fleet as part of the Company’s compressor optimization initiative to improve fuel gas 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 CO₂ capture and the sequestration of CO₂ in oil sands tailings. The Company implemented a fuel gas import project in its North Sea operations to reduce diesel consumption in addition to continued focus on its flare reduction program in both the North Sea and Offshore Africa operations.

B. 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, and Manitoba. 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.

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 and are not subject to escalating rentals 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 their respective 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.

Alberta Oil Sands royalties are based on a sliding scale ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout, depending on benchmark crude oil pricing.

In addition to government royalties, the Company is subject to federal and provincial income taxes in Canada at a combined rate of approximately 25% after allowable deductions.

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During 2011, the Canadian federal government enacted legislation to implement several taxation changes. These changes include a requirement that, beginning in 2012, partnership income must be included in the taxable income of each corporate partner based on the tax year of the partner, rather than the fiscal year of the partnership. The legislation includes a five year transition provision and has no impact on net earnings.

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 PRT of 50% charged on crude oil and natural gas profits. Approvals granted on or after March 16, 1993 are exempted from PRT. Profits for PRT purposes are calculated on a field-by-field basis by deducting field production 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 overall tax rate applicable to net operating income from oil and gas activities, including PRT and corporate and supplementary income tax charges, is 62% for non-PRT paying fields and 81% for PRT paying fields, excluding the impact of a restriction on decommissioning expenditures.

In 2012, the UK government implemented the Brownfield Allowance which allows for an agreed allowance related to property development for certain pre-approved qualifying field developments.

In 2013, the UK government introduced a Decommissioning Relief Deed (“DRD”) which is a contractual mechanism whereby the UK government guarantees its participation in future field abandonments through a recovery of PRT and corporate income tax.

Offshore 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.

C. COMPETITIVE FACTORS

The energy industry is highly competitive in all aspects of the business 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, the transportation and marketing of crude oil, NGLs, natural gas, and electricity and the attraction and retention of skilled personnel. The Company’s competitors

include both integrated and non integrated crude oil and natural gas companies as well as other petroleum products and energy sources.

D. 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 primarily 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 ability to secure adequate transportation for products which could be affected by pipeline constraints and other factors, the availability of alternate fuel

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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, Pelican Lake, the Kirby Thermal Oil Sands Project, Redwater Partnership and international projects, 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 41% of the Company's 2013 production on a BOE basis was primary heavy crude oil, Pelican Lake heavy crude oil, and bitumen (thermal oil). The market prices for these products may differ from the established market indices for light and medium grades of crude oil due principally to quality differences. As a result, the price received for these products may differ from the benchmark they are priced against. Future quality differentials are uncertain and a significant increase could have a material adverse effect on the Company's financial condition.

Canadian Natural conducts assessments of the carrying value of its assets in accordance with IFRS. 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.

Operational Risk

Exploring for, producing, mining, extracting, upgrading and transporting crude oil, NGLs and natural gas 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, interruption of operations and loss of production, whether caused by human error or nature. In addition to the foregoing, the Horizon operations are also subject to loss of production, potential shutdowns and increased production costs due to the integration of the various component parts.

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, Africa 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.

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 level, availability and duration of compliance mechanisms and resolution of federal/provincial harmonization agreements. The Company continues to pursue GHG emission reduction initiatives including: solution gas conservation, compressor optimization to improve fuel gas efficiency, CO₂ capture and sequestration in oil sands tailings, CO₂ capture and storage in association with EOR, participation in an industry initiative to promote an integrated CO₂ capture and storage network and participation in organizations that are researching technologies to reduce GHG emissions specifically COSIA and CMC.

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 is also developing a comprehensive management system for air pollutants.

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In Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO₂e annually. Three of the Company's facilities, the Horizon facility, the Primrose/Wolf Lake in situ heavy crude oil facilities and the Hays sour natural gas plant are subject to compliance under the regulations. The Kirby South in situ heavy crude oil facility will be subject to compliance under regulations in 2016. The British Columbia carbon tax is currently being assessed at \$30/tonne of CO₂e on fuel consumed and gas flared in the province. Saskatchewan released draft GHG regulations that regulate facilities emitting more than 50 kilotonnes of CO₂e annually and will likely require the North Tangleflags in situ heavy oil facility to meet the reduction target for its GHG emissions once the governing legislation comes into force. In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 – 2007) of the UK National Allocation Plan, the Company operated below its CO₂ allocation. In Phase 2 (2008 – 2012) the Company's CO₂ allocation was decreased below the Company's operations emissions. In Phase 3 (2013 - 2020) the Company's CO₂ allocation was further reduced. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO₂ emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

The US Environmental Protection Agency ("EPA") is proceeding to regulate GHGs under the Clean Air Act. This EPA action is subject to legal and political challenges, the outcome of which cannot be predicted. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory and judicial decisions made within the United States. Various states in the United 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 regulations on the Company's operations will increase capital expenditures and production expense, including those related to Horizon and the Company's other existing and certain planned oil sands projects. Depending on the legislation enacted, this may have an adverse effect on the Company's financial condition.

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

In February 2009, the Energy Resources Conservation Board (ERCB), now the Alberta Energy Regulator or AER, released Directive 74 - Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes. The Directive establishes performance criteria for tailings operations and sets out the requirements for the approval, monitoring and reporting in respect of tailings ponds and tailings management plans.

Directive 74 allows companies the flexibility to select the technology or technologies that will be most applicable to their operation in order to achieve the stipulated performance criteria. The Company, with the collaboration of COSIA, has undertaken an in-depth analysis and selected a technology that limits the environmental footprint of tailings reclamation and allows for the progressive reclamation of our tailings facilities. Although the selected technology is innovative and environmentally beneficial, there is a risk that the Company will not be successful in meeting the stipulated performance criteria once commercial operations commence in 2015. In the event that our primary technology selection is not successful in meeting the stipulated performance criteria, the Company has also designed a proven secondary technology process into the tailings facility.

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.

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.

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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 production 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 of reserves that may be developed in the future are often based upon volumetric calculations and upon analogy to actual production history from similar reservoirs and wells. Subsequent evaluation of the same reserves based upon production history will result in variations in the previously estimated reserves.

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 and is impacted by our ability to maintain investment grade credit ratings and the condition of the capital and credit markets. In addition, changes in credit ratings may affect the Company's ability to, and the associated costs of, entering into ordinary course derivative or hedging transactions, as well as entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

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, risk 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, including compliance with existing and emerging anti-corruption laws, 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.

Risk Management 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.

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Other Business Risks

Other business risks which may negatively impact the Company's financial condition include severe weather conditions, labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner, 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, risk of increases in government taxes and changes to the royalty regime and risk to the Company's reputation resulting from operational activities that may cause personal injury, property damage or environmental damage. The Company utilizes a variety of information systems in its operations. A significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach of security could adversely affect the Company's operations. The majority of the Company's assets are held in one or more corporate subsidiaries or partnerships. 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.

FORM 51-101F1 STATEMENT OF RESERVES DATA AND OTHER INFORMATION

For the year ended December 31, 2013 the Company retained Independent Qualified Reserves Evaluators ("Evaluators"), Sproule Associates Limited and Sproule International Limited (together as "Sproule") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved and proved plus probable reserves with an effective date of December 31, 2013 and a preparation date of February 3, 2014. Sproule evaluated the North America and International light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), natural gas and NGLs reserves. GLJ evaluated the Horizon SCO reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and related net present value of future net revenue of the remaining reserves.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 "Extractive Activities - Oil and Gas" in the Company's Form 40-F filed with the SEC in the "Supplementary Oil and Gas Information" section of the Company's Annual Report on pages 92 to 99 which is incorporated herein by reference.

The estimates of future net revenue presented in the tables below do not represent the fair market value of the reserves.

There is no assurance that the price and cost assumptions contained in the forecast case will be attained and variances could be material. The recovery and reserves estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater or less than the estimate provided herein.

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Summary of Company Gross Reserves by Product

As of December 31, 2013

Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	95	123	216	321	1,848	2,773	63	3,128
Developed								
Non-Producing	4	23	1	90	-	251	4	164
Undeveloped	18	98	41	746	363	1,136	43	1,498
Total Proved	117	244	258	1,157	2,211	4,160	110	4,790
Probable	49	90	104	1,013	1,078	1,721	64	2,685
Total Proved plus Probable	166	334	362	2,170	3,289	5,881	174	7,475
North Sea								
Proved								
Developed Producing	38					8		39
Developed								
Non-Producing	18					63		28
Undeveloped	168					20		172
Total Proved	224					91		239
Probable	101					34		107
Total Proved plus Probable	325					125		346
Offshore Africa								
Proved								
Developed Producing	34					40		41
Developed								
Non-Producing	-					-		-
Undeveloped	65					14		67
Total Proved	99					54		108
Probable	54					49		62
Total Proved plus Probable	153					103		170
Total Company								
Proved								
Developed Producing	167	123	216	321	1,848	2,821	63	3,208
Developed								
Non-Producing	22	23	1	90	-	314	4	192

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Undeveloped	251	98	41	746	363	1,170	43	1,737
Total Proved	440	244	258	1,157	2,211	4,305	110	5,137
Probable	204	90	104	1,013	1,078	1,804	64	2,854
Total Proved plus Probable	644	334	362	2,170	3,289	6,109	174	7,991

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Summary of Company Net Reserves by Product
As of December 31, 2013
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	82	101	164	244	1,564	2,485	45	2,614
Developed								
Non-Producing	3	19	1	65	-	211	2	125
Undeveloped	15	82	32	574	263	988	34	1,165
Total Proved	100	202	197	883	1,827	3,684	81	3,904
Probable	40	72	71	776	836	1,454	50	2,087
Total Proved plus Probable	140	274	268	1,659	2,663	5,138	131	5,991
North Sea								
Proved								
Developed Producing	38					8		39
Developed								
Non-Producing	18					63		28
Undeveloped	168					20		172
Total Proved	224					91		239
Probable	101					34		107
Total Proved plus Probable	325					125		346
Offshore Africa								
Proved								
Developed Producing	29					27		34
Developed								
Non-Producing	-					-		-
Undeveloped	51					11		53
Total Proved	80					38		87
Probable	42					32		47
Total Proved plus Probable	122					70		134
Total Company								
Proved								
Developed Producing	149	101	164	244	1,564	2,520	45	2,687
Developed								
Non-Producing	21	19	1	65	-	274	2	153
Undeveloped	234	82	32	574	263	1,019	34	1,390

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Total Proved	404	202	197	883	1,827	3,813	81	4,230
Probable	183	72	71	776	836	1,520	50	2,241
Total Proved plus Probable	587	274	268	1,659	2,663	5,333	131	6,471

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NOTES

1. “Company Gross reserves” are the Company’s working interest share of reserves before deduction of royalties and without including any royalty interests of the Company.
2. “Company Net reserves” means the Company’s gross reserves less all royalties payable to others plus royalties receivable from others.
3. “Reserves” are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as at a given date, based on analysis of drilling, geological, geophysical, and engineering data, with the use of established technology and under specified economic conditions which are generally accepted as being reasonable.

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

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

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

- “Developed reserves” are reserves that are expected to be recovered from (i) existing wells and installed facilities or, if the facilities have not been installed, that would involve a low expenditure (compared to the cost of drilling a well) to put the reserves on production, and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. The developed category may be subdivided into producing and non-producing.
- “Undeveloped reserves” are reserves that are expected to be recovered from known accumulations with 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 producibility at greater distances.

4. The reserve evaluation involved data supplied by the Company with respect to geological and engineering data, adjustments for product quality, heating value and transportation, interests owned, royalties payable, production costs, capital costs and contractual commitments. This data was found by the Evaluators to be reasonable.

A report on reserves data by the Evaluators is provided in Schedule “A” to this Annual Information Form. A report by the Company’s management and directors on crude oil, NGLs and natural gas reserves disclosure is provided in Schedule “B” to this Annual Information Form.

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Summary of Net Present Values of Future Net Revenue Before Income Taxes

As of December 31, 2013

Forecast Prices and Costs

MM\$	Discount @ 0%	Discount @ 5%	Discount @ 10%	Discount @ 15%	Discount @ 20%	Unit Value Discounted at 10%/year \$/BOE (1)
North America						
Proved						
Developed Producing	106,967	49,504	32,923	25,546	21,277	12.59
Developed Non-Producing	5,107	4,079	3,398	2,917	2,561	27.18
Undeveloped	50,261	32,765	17,687	9,253	4,521	15.18
Total Proved	162,335	86,348	54,008	37,716	28,359	13.83
Probable	130,094	41,061	18,623	10,837	7,278	8.92
Total Proved plus Probable	292,429	127,409	72,631	48,553	35,637	12.12
North Sea						
Proved						
Developed Producing	839	739	662	602	553	16.97
Developed Non-Producing	1,193	991	843	731	645	30.11
Undeveloped	9,271	5,657	3,656	2,470	1,726	21.26
Total Proved	11,303	7,387	5,161	3,803	2,924	21.59
Probable	8,836	4,763	2,931	1,987	1,447	27.39
Total Proved plus Probable	20,139	12,150	8,092	5,790	4,371	23.39
Offshore Africa						
Proved						
Developed Producing	1,118	954	838	751	682	24.65
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	4,714	2,782	1,792	1,230	886	33.81
Total Proved	5,832	3,736	2,630	1,981	1,568	30.23
Probable	4,464	2,423	1,440	916	611	30.64
Total Proved plus Probable	10,296	6,159	4,070	2,897	2,179	30.37
Total Company						
Proved						
Developed Producing	108,924	51,197	34,423	26,899	22,512	12.81
Developed Non-Producing	6,300	5,070	4,241	3,648	3,206	27.72
Undeveloped	64,246	41,204	23,135	12,953	7,133	16.64
Total Proved	179,470	97,471	61,799	43,500	32,851	14.61
Probable	143,394	48,247	22,994	13,740	9,336	10.26
Total Proved plus Probable	322,864	145,718	84,793	57,240	42,187	13.10

(1) Unit values are based on Company net reserves.

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Summary of Net Present Values of Future Net Revenue After Income Taxes(1)
As of December 31, 2013
Forecast Prices and Costs

MM\$	Discount @ 0%	Discount @ 5%	Discount @ 10%	Discount @ 15%	Discount @ 20%
North America					
Proved					
Developed Producing	82,933	39,606	26,854	21,068	17,674
Developed Non-Producing	3,828	3,051	2,539	2,178	1,911
Undeveloped	37,739	23,755	12,174	5,741	2,148
Total Proved	124,500	66,412	41,567	28,987	21,733
Probable	97,233	30,549	13,748	7,920	5,257
Total Proved plus Probable	221,733	96,961	55,315	36,907	26,990
North Sea					
Proved					
Developed Producing	337	299	271	249	231
Developed Non-Producing	347	306	274	249	229
Undeveloped	2,417	1,474	951	640	444
Total Proved	3,101	2,079	1,496	1,138	904
Probable	2,382	1,334	850	594	445
Total Proved plus Probable	5,483	3,413	2,346	1,732	1,349
Offshore Africa					
Proved					
Developed Producing	760	672	605	553	510
Developed Non-Producing	-	-	-	-	-
Undeveloped	3,698	2,210	1,440	999	726
Total Proved	4,458	2,882	2,045	1,552	1,236
Probable	3,377	1,854	1,113	713	479
Total Proved plus Probable	7,835	4,736	3,158	2,265	1,715
Total Company					
Proved					
Developed Producing	84,030	40,577	27,730	21,870	18,415
Developed Non-Producing	4,175	3,357	2,813	2,427	2,140
Undeveloped	43,854	27,439	14,565	7,380	3,318
Total Proved	132,059	71,373	45,108	31,677	23,873
Probable	102,992	33,737	15,711	9,227	6,181
Total Proved plus Probable	235,051	105,110	60,819	40,904	30,054

(1) After tax net present values consider the Company's existing tax pool balances.

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Additional Information Concerning Future Net Revenue

The following table summarizes the undiscounted future net revenue as at December 31, 2013 using forecast prices and costs.

Total Future Net Revenue (Undiscounted)

MM\$	North America		North Sea		Offshore Africa		Total	
	Proved	Proved plus Probable	Proved	Proved plus Probable	Proved	Proved plus Probable	Proved	Proved plus Probable
Revenue	461,107	777,456	28,548	42,325	10,398	15,971	500,053	835,752
Royalties	82,818	148,215	-	-	338	559	83,156	148,774
Production Costs	161,778	260,263	11,418	15,731	2,722	2,756	175,918	278,750
Development Costs	53,444	75,277	5,696	6,316	1,475	2,301	60,615	83,894
Abandonment (1)	732	1,272	131	139	31	59	894	1,470
Future Net Revenue								
Before Income Taxes	162,335	292,429	11,303	20,139	5,832	10,296	179,470	322,864
Income Taxes	37,835	70,696	8,202	14,656	1,374	2,461	47,411	87,813
Future Net Revenue								
After Income Taxes (2)	124,500	221,733	3,101	5,483	4,458	7,835	132,059	235,051

(1) The evaluation of reserves includes only abandonment costs for future drilling locations that have been assigned reserves.

(2) Future net revenue is prior to provision for interest, general and administrative expenses and the impact of any risk management activities.

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The following table summarizes the future net revenue by production group as at December 31, 2013 using forecast prices and costs.

Reserves Category	Production Group	Future Net Revenue By Production Group	
		Future Net Revenue Before Income Taxes (discounted at 10%/year) (MM\$)	Unit Value (1) (\$/BOE)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	11,125	24.57
	Primary Heavy Crude Oil (including solution gas)	4,576	22.38
	Pelican Lake Heavy Crude Oil (including solution gas)	3,993	20.30
	Bitumen (Thermal Oil)	16,943	19.19
	Synthetic Crude Oil	19,977	10.93
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	5,185	7.78
	Total	61,799	14.61
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	16,520	25.05
	Primary Heavy Crude Oil (including solution gas)	6,434	23.22
	Pelican Lake Heavy Crude Oil (including solution gas)	5,343	19.90
	Bitumen (Thermal Oil)	22,135	13.35
	Synthetic Crude Oil	27,209	10.22
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	7,152	7.57
	Total	84,793	13.10

(1) Unit values are based on Company net reserves.

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Pricing Assumptions

The crude oil, NGLs and natural gas reference pricing and the inflation and exchange rates used in the preparation of reserves and related future net revenue estimates are as per the Sproule price forecast dated December 31, 2013. The following is a summary of the Sproule price forecast.

	2014	2015	2016	2017	2018	Average annual increase thereafter
Crude Oil and NGLs						
WTI(1) (US\$/bbl)	\$94.65	\$88.37	\$84.25	\$95.52	\$96.96	1.50%
WCS(2) (C\$/bbl)	\$77.81	\$75.02	\$75.29	\$85.36	\$86.64	1.50%
Edmonton Par(3) (C\$/bbl)	\$92.64	\$89.31	\$89.63	\$101.62	\$103.14	1.50%
Edmonton C5+(4) (C\$/bbl)	\$103.50	\$99.78	\$100.14	\$113.53	\$115.24	1.50%
North Sea Brent(5) (US\$/bbl)	\$108.06	\$102.73	\$97.42	\$106.14	\$107.73	1.50%
Natural Gas						
AECO(6) (C\$/MMBtu)	\$4.00	\$3.99	\$4.00	\$4.93	\$5.01	1.50%
BC Westcoast Station 2(7) (C\$/MMBtu)	\$3.95	\$3.94	\$3.95	\$4.88	\$4.96	1.50%
Henry Hub(8) (US\$/MMBtu)	\$4.17	\$4.15	\$4.17	\$5.04	\$5.12	1.50%

- (1) “WTI” refers to the price of West Texas Intermediate crude oil at Cushing, Oklahoma.
- (2) “WCS” refers to Western Canadian Select, a blend of heavy crude oils and bitumen with sweet synthetic and condensate diluents at Hardisty, Alberta; reference price used in the preparation of primary heavy crude oil, Pelican Lake heavy crude oil and bitumen (thermal oil) reserves.
- (3) “Edmonton Par” refers to the price of light gravity (40° API), low sulphur content crude oil at Edmonton, Alberta; reference price used in the preparation of light and medium crude oil and SCO reserves.
- (4) “Edmonton C5+” refers to pentanes plus at Edmonton, Alberta; reference price used in the preparation of NGLs reserves; also used in determining the diluent costs associated with primary heavy crude oil and bitumen (thermal oil) reserves.
- (5) “North Sea Brent” refers to the benchmark price for European, African and Middle Eastern crude oil; reference price used in the preparation of North Sea and Offshore Africa light crude oil reserves.
- (6) “AECO” refers to the Alberta natural gas trading price at the AECO-C hub in southeast Alberta; reference price used in the preparation of North America (excluding British Columbia) natural gas reserves.
- (7) “BC Westcoast Station 2” refers to the natural gas delivery point on the Spectra Energy system at Chetwynd, British Columbia; reference price used in the preparation of British Columbia natural gas reserves.
- (8) “Henry Hub” refers to a distribution hub on the natural gas pipeline system in Erath, Louisiana and is the pricing point for natural gas futures on the New York Mercantile Exchange.

The forecast prices and costs assume the continuance of current laws and regulations, and any increases in wellhead selling prices also take inflation into account. Sales prices are based on reference prices as detailed above and adjusted for quality and transportation on an individual property basis. A foreign exchange rate of 0.9400 US\$/Cdn\$ was used in the 2013 evaluation.

Capital and production costs are escalated at Sproule’s cost inflation rate of 1.5% per year for all products except SCO. For SCO, capital and operating costs are escalated at GLJ’s cost inflation rates of 4.0% for 2015 to 2016, 3.0% for 2017, 2.0% for 2018 and 1.5% after 2018.

The Company's 2013 average pricing, net of blending costs and excluding risk management activities, was \$98.35/bbl for light and medium crude oil, \$69.06/bbl for primary heavy crude oil, \$70.62/bbl for Pelican Lake heavy crude oil, \$66.14/bbl for bitumen (thermal oil), \$100.75/bbl for SCO, \$57.10/bbl for NGLs and \$3.58/Mcf for natural gas.

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Reconciliation of Company Gross Reserves by Product
As of December 31, 2013
Forecast Prices and Cost

PROVED

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2012	113	204	267	1,066	2,255	3,985	94	4,663
Discoveries	-	1	-	-	-	6	-	2
Extensions	3	36	-	51	-	163	13	130
Infill Drilling	5	11	2	-	-	73	3	33
Improved Recovery	-	1	-	-	-	1	-	1
Acquisitions	9	-	-	-	-	141	2	35
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	1	1	-	2	(2)	(99)	(1)	(16)
Technical Revisions	2	40	5	73	(5)	303	8	173
Production	(16)	(50)	(16)	(35)	(37)	(412)	(9)	(231)
December 31, 2013	117	244	258	1,157	2,211	4,160	110	4,790

North Sea

December 31, 2012	227					82		240
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	6					15		8
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(2)					(4)		(2)
Production	(7)					(2)		(7)
December 31, 2013	224					91		239

Offshore Africa

December 31, 2012	103					69		115
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-

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Dispositions	-	-	-
Economic Factors	-	-	-
Technical Revisions	1	(6)	-
Production	(5)	(9)	(7)
December 31, 2013	99	54	108

Total Company

December 31, 2012	443	204	267	1,066	2,255	4,136	94	5,018
Discoveries	-	1	-	-	-	6	-	2
Extensions	3	36	-	51	-	163	13	130
Infill Drilling	5	11	2	-	-	73	3	33
Improved Recovery	-	1	-	-	-	1	-	1
Acquisitions	15	-	-	-	-	156	2	43
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	1	1	-	2	(2)	(99)	(1)	(16)
Technical Revisions	1	40	5	73	(5)	293	8	171
Production	(28)	(50)	(16)	(35)	(37)	(423)	(9)	(245)
December 31, 2013	440	244	258	1,157	2,211	4,305	110	5,137

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PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2012	51	80	105	1,056	1,096	1,589	44	2,697
Discoveries	-	-	-	-	-	1	1	1
Extensions	2	19	-	49	-	261	20	134
Infill Drilling	1	4	-	-	-	19	-	8
Improved Recovery	-	-	-	-	-	-	-	-
Acquisitions	3	-	-	-	-	35	-	8
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	1	-	1	(2)	1	18	-	4
Technical Revisions	(9)	(13)	(2)	(90)	(19)	(202)	(1)	(167)
Production	-	-	-	-	-	-	-	-
December 31, 2013	49	90	104	1,013	1,078	1,721	64	2,685

North Sea

December 31, 2012	105					20		109
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	1					5		2
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(5)					9		(4)
Production	-					-		-
December 31, 2013	101					34		107

Offshore Africa

December 31, 2012	55	42	62
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
I m p r o v e d Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
E c o n o m i c Factors	(1)	-	(1)
T e c h n i c a l Revisions	-	7	1
Production	-	-	-
December 31, 2013	54	49	62

Total Company

December 31, 2012	211	80	105	1,056	1,096	1,651	44	2,868
Discoveries	-	-	-	-	-	1	1	1
Extensions	2	19	-	49	-	261	20	134
Infill Drilling	1	4	-	-	-	19	-	8
I m p r o v e d Recovery	-	-	-	-	-	-	-	-
Acquisitions	4	-	-	-	-	40	-	10
Dispositions	-	-	-	-	-	-	-	-
E c o n o m i c Factors	-	-	1	(2)	1	18	-	3
T e c h n i c a l Revisions	(14)	(13)	(2)	(90)	(19)	(186)	(1)	(170)
Production	-	-	-	-	-	-	-	-
December 31, 2013	204	90	104	1,013	1,078	1,804	64	2,854

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PROVED PLUS PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2012	164	284	372	2,122	3,351	5,574	138	7,360
Discoveries	-	1	-	-	-	7	1	3
Extensions	5	55	-	100	-	424	33	264
Infill Drilling	6	15	2	-	-	92	3	41
Improved Recovery	-	1	-	-	-	1	-	1
Acquisitions	12	-	-	-	-	176	2	43
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	2	1	1	-	(1)	(81)	(1)	(12)
Technical Revisions	(7)	27	3	(17)	(24)	101	7	6
Production	(16)	(50)	(16)	(35)	(37)	(412)	(9)	(231)
December 31, 2013	166	334	362	2,170	3,289	5,881	174	7,475

North Sea

December 31, 2012	332					102		349
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	7					20		10
Dispositions	-					-		-
Economic Factors	-					-		-
Technical Revisions	(7)					5		(6)
Production	(7)					(2)		(7)
December 31, 2013	325					125		346

Offshore Africa

December 31, 2012	158					111		177
Discoveries	-					-		-
Extensions	-					-		-
Infill Drilling	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	(1)					-		(1)
Technical Revisions	1					1		1
Production	(5)					(9)		(7)

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December 31, 2013	153				103		170	
Total Company								
December 31, 2012	654	284	372	2,122	3,351	5,787	138	7,886
Discoveries	-	1	-	-	-	7	1	3
Extensions	5	55	-	100	-	424	33	264
Infill Drilling	6	15	2	-	-	92	3	41
Improved Recovery	-	1	-	-	-	1	-	1
Acquisitions	19	-	-	-	-	196	2	53
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	1	1	1	-	(1)	(81)	(1)	(13)
Technical Revisions	(13)	27	3	(17)	(24)	107	7	1
Production	(28)	(50)	(16)	(35)	(37)	(423)	(9)	(245)
December 31, 2013	644	334	362	2,170	3,289	6,109	174	7,991

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At December 31, 2013, the company gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 4,420 MMbbl, and gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 6,973 MMbbl. Proved reserve additions and revisions replaced 152% of 2013 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 143 MMbbl, and additions to proved plus probable reserves amounted to 243 MMbbl. Net positive revisions amounted to 123 MMbbl for proved reserves and net negative revisions amounted to 16 MMbbl for proved plus probable reserves, primarily due to technical revisions to prior estimates.

At December 31, 2013, the company gross proved natural gas reserves totaled 4,305 Bcf, and gross proved plus probable natural gas reserves totaled 6,109 Bcf. Proved reserve additions and revisions replaced 140% of 2013 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 398 Bcf, and additions to proved plus probable reserves amounted to 719 Bcf. Net positive revisions amounted to 194 Bcf for proved reserves and 26 Bcf for proved plus probable reserves, primarily due to technical revisions to prior estimates.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are reserves expected to be recovered from known accumulations and require significant expenditure to develop and make capable of production. Proved and probable undeveloped reserves were estimated by the Evaluators in accordance with the procedures and standards contained in the COGE Handbook.

Year	Proved Undeveloped Reserves							
	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
2011 First Attributed	8	29	8	70	-	240	21	176
2011 Total	209	79	71	710	288	1,165	37	1,589
2012 First Attributed	6	20	-	77	-	32	1	109
2012 Total	221	96	39	724	418	1,145	38	1,727
2013 First Attributed	3	20	2	-	-	180	13	68
2013 Total	251	98	41	746	363	1,170	43	1,737

Year	Probable Undeveloped Reserves							
	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)

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2011 First								
Attributed	4	17	6	17	388	160	14	473
2011 Total	153	37	38	749	1,142	564	20	2,233
2012 First								
Attributed	8	13	-	283	-	40	3	314
2012 Total	144	47	22	1,046	988	599	24	2,371
2013 First								
Attributed	3	16	-	16	-	267	20	100
2013 Total	145	50	22	1,001	978	744	42	2,362

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Bitumen (thermal oil) accounts for approximately 43% of the Company's total proved undeveloped BOE reserves and 42% of the total probable undeveloped BOE reserves. These undeveloped reserves are scheduled to be developed in a staged approach to align with current operational capacities and efficient capital spending commitments over the next forty years. These plans are continuously reviewed and updated for internal and external factors affecting planned activity.

Undeveloped reserves, for products other than bitumen (thermal oil), are scheduled to be developed over the next ten years. The Company continually reviews the economic viability and ranking of these undeveloped reserves within the total portfolio of development projects. Development opportunities are then pursued based on capital availability and allocation.

Significant Factors or Uncertainties Affecting Reserves Data

The development plan for the Company's undeveloped reserves is based on forecast price and cost assumptions. Projects may be advanced or delayed based on actual prices that occur.

The evaluation of reserves is a process that can be significantly affected by a number of internal and external factors. Revisions are often necessary resulting in changes in technical data acquired, historical performance, fluctuations in production costs, development costs and product pricing, economic conditions, changes in royalty regimes and environmental regulations, and future technology improvements. See "Risk Factors" in this AIF for further information.

Future Development Costs

The following table summarizes the undiscounted future development costs, excluding abandonment costs, using forecast prices and costs as of December 31, 2013.

Year	Future Development Costs (Undiscounted)							
	North America		North Sea		Offshore Africa		Total	
	Proved (MM\$)	Proved plus Probable (MM\$)	Proved (MM\$)	Proved plus Probable (MM\$)	Proved (MM\$)	Proved plus Probable (MM\$)	Proved (MM\$)	Proved plus Probable (MM\$)
2014	4,932	5,631	409	409	162	222	5,503	6,262
2015	5,652	6,378	450	450	316	501	6,418	7,329
2016	4,319	4,965	577	577	313	479	5,209	6,021
2017	3,876	4,512	479	479	14	258	4,369	5,249
2018	2,991	2,767	486	486	13	67	3,490	3,320
Thereafter	31,674	51,024	3,295	3,915	657	774	35,626	55,713
Total	53,444	75,277	5,696	6,316	1,475	2,301	60,615	83,894

Management believes internally generated cash flows, existing credit facilities and access to debt capital markets are sufficient to fund future development costs. We do not anticipate the costs of funding would make the development of any property uneconomic.

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Other Oil and Gas Information

Daily Production

Set forth below is a summary of the production from crude oil, NGLs and natural gas properties for the fiscal years ended December 31, 2013 and 2012.

Region	2013 Average Daily Production Rates		2012 Average Daily Production Rates	
	Crude Oil & NGLs (Mbbl)	Natural Gas (MMcf)	Crude Oil & NGLs (Mbbl)	Natural Gas (MMcf)
North America				
Northeast British Columbia	14	329	11	340
Northwest Alberta	27	461	24	481
Northern Plains	283	171	271	197
Southern Plains	13	166	12	177
Southeast Saskatchewan	7	3	8	3
Oil Sands Mining & Upgrading	100	-	86	-
North America Total	444	1,130	412	1,198
International				
North Sea UK Sector	18	4	20	2
Offshore Africa	16	24	19	20
International Total	34	28	39	22
Company Total	478	1,158	451	1,220

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, British Columbia, producing light and medium 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

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emerging unconventional shale gas plays. The 2006 acquisition of ACC significantly increased the asset base in this area. In 2010, a natural gas processing plant with a design capacity of 50 MMcf/d was completed at our Septimus Montney gas play and in 2011 the Company completed a pipeline to a deep cut gas facility which increased liquids recoveries. In 2013 a plant expansion was completed and production capacity of 125 MMcf/d and 12,200 bbl/d of liquids was achieved with the completion of new wells. 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, Alberta. The majority of the Company's initial holdings in the region were obtained through the 2002 acquisition of Rio Alto Exploration Ltd. and the 2006 acquisition of ACC. The ACC acquisition added two very prospective properties to this region, Wild River and Peace River Arch. The Wild River assets provide a premium 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. In both 2010 and 2011, the Company purchased additional assets in the area which further complemented the asset base. During 2013, in connection with the 2013 acquisition of Barrick Energy Inc., the Company acquired light crude properties, together with facilities and unproved land. Northwest Alberta provides exploration and exploitation opportunities in combination with an extensive owned and operated infrastructure. In this region, the Company 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 opportunities similar to the geology of the Company's Northern Plains core region. The Company is also pursuing development of shale gas plays 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.

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Northern Plains

This region extends just south of Edmonton, Alberta and north to Fort McMurray, Alberta and from the Northwest Alberta region 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.

Natural gas in this region is produced from shallow, low-risk, multi-zone prospects. The Company targets low-risk exploration and development opportunities and some shale gas exploration in this area.

Near Lloydminster, Alberta, reserves of primary 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. A key component to maintaining profitability in the production of heavy crude oil is to be an effective and efficient producer. The Company continues to control 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 acquisitions. 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 production cost. 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, Alberta are the Company's holdings at Pelican Lake. These assets produce Pelican Lake heavy crude oil from the Wabasca formation with gravities of 12°-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 is using an EOR scheme through polymer flooding to increase the ultimate recoveries from the field. At the end of 2013, approximately 56% of the field had been converted to polymer injection. A new 20,000 bbl/d battery was completed in the first half of 2013.

Production of bitumen (thermal oil) from the 100% owned Primrose Field located near Bonnyville, Alberta involves processes that utilize steam to increase the recovery of the bitumen (10°-11°API). The two processes employed by the Company are CSS and SAGD. Both recovery processes inject steam to heat the bitumen deposits, reducing the 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. In order to expand its pipeline infrastructure the Company has participated in the expansion of the Cold Lake pipeline with construction anticipated to be completed in 2016. The

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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 bitumen recovery.

During 2013, the Company discovered bitumen emulsion at surface in areas of the Primrose field. The Company's view is that the cause of the occurrence is mechanical in nature and is working collaboratively with the regulators in the causation review and remediation plans. The Company's near term steaming plan at the Primrose field has been modified, with steaming being restricted in certain areas until the causation review with the regulators is complete.

The regulatory application for the Kirby In Situ Oil Sands Project ("Kirby South Phase 1"), located approximately 85 km northeast of Lac la Biche, was approved in the third quarter 2010 and sanctioned by the Board of Directors, with construction commencing in the fourth quarter 2010. First steam injection was achieved at Kirby South in September 2013. At December 31, 2013, steam was being circulated through 6 pads with well response as expected. Subsequent to December 31, 2013 15 well pairs have been fully converted to the production stage. In 2012, the Company acquired approximately 49 sections (12,630 hectares) of additional oil sands rights immediately adjacent to Canadian Natural's Kirby In Situ Oil Sands Expansion Project ("Kirby Expansion Project"). The Company is in the early stages of integrating the acquired lands into the development plan and is expecting to increase production capacity for future phases in Kirby North and Kirby South.

Southern Plains and Southeast Saskatchewan

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

Reserves of natural gas, NGLs and light and medium 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. The Company's extensive shallow gas assets in this region were augmented by the 2006 acquisition of ACC. The Company continues to acquire additional assets in the area which further complement the asset base.

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 Southeast Saskatchewan area is located in the south eastern portion of the province extending into Manitoba. This region became a core region of the Company in mid-1996. This region produces primarily light sour crude oil from as many as seven productive horizons found at depths up to 2,700 meters.

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Oil Sands Mining and Upgrading

Canadian Natural owns a 100% working interest in its Athabasca oil sands leases in northern Alberta, of which the main lease 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, Alberta. The site is accessible by a private road and private airstrip. The oil sands resource is found in the Cretaceous McMurray Formation which is further subdivided into three informal members: lower, middle and upper. Most of Horizon's oil sands resource is found within the lower and middle McMurray Formation at depths ranging from 50 to 100 meters below the surface.

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 34°API SCO. The upgrader capacity is 110,000 bbl/d of SCO. The SCO is transported from the site by a pipeline with a design capacity of 232,000 bbl/d to the Edmonton area for distribution. An on-site cogeneration plant with a design capacity of 115 MW provides power and steam for the operations.

Site clearing and pre-construction preparation activities commenced in 2004 following regulatory approvals 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 production averaged 100,284 bbl/day in 2013.

On January 6, 2011, the Company suspended SCO production at its Horizon operations due to a fire in the primary upgrading coking plant. On August 16, the Company successfully and safely resumed production with first pipeline deliveries commencing on August 18, 2011.

On February 5, 2012, the Company temporarily suspended SCO production to complete unplanned maintenance on the fractionating unit in the primary upgrading facility. In March 2012, the maintenance was completed and pipeline deliveries re-commenced.

In May 2013, the Company successfully completed a planned maintenance turnaround. During the outage, all major scopes of work were completed including the change out of catalysts in the hydro-treating units.

Overall Horizon Phase 2/3 construction reached approximately 34% physical completion in 2013. Phase 2/3 expansion activity was focused on field construction of the gas recovery unit, sulphur recovery unit, butane treatment unit, coker expansion, tank farms, cooling water tower, tailings, hydrotransport, froth treatment and extraction trains 3 and 4, along with engineering related to the froth treatment plants, extraction retrofit of trains 1 and 2, hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit.

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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 2013, the Company produced from 11 crude oil fields.

The northerly fields are centered around the Ninian Field where the Company has an 87.1% operated 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 acquired an additional 67.0% working interest in the Strathspey field in July 2013 and assumed operatorship of the field with total working interest of 73.5%. The Company also has an interest in 8 licences covering 11 blocks and part blocks surrounding the Ninian and Murchison platforms and 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.

In December 2011, the Banff FPSO and subsea infrastructure suffered storm damage. Operations at Banff/Kyle, with combined net production of approximately 3,500 bbl/d, were suspended. The FPSO is currently undergoing repairs and is targeted to be back in the field early in the third quarter of 2014. The associated repair costs, net of insurance recoveries, are not expected to be significant. The financial impact to operations has been partially mitigated through receipt of business interruption insurance proceeds.

During 2013, the Company received Brownfield Allowance approvals for the Tiffany and Ninian fields. At the Tiffany field, the Company completed one injection well conversion and drilled one production well with production of approximately 1,500 bbl/d. The Company also commenced drilling in the Ninian field in the fourth quarter of 2013.

The decommissioning activities at the Murchison platform commenced in the fourth quarter of 2013 and the Company estimates the decommissioning efforts will continue for approximately 5 years. In 2013, the Company entered into a Decommissioning Relief Deed (“DRD”) with the UK government. The DRD is a contractual mechanism whereby the UK government guarantees its participation in future field abandonments through a recovery of PRT and corporate income tax.

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Offshore Africa

Côte d'Ivoire

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

The Company has a 58.7% operated interest 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.

During the fourth quarter of 2011, the Company sanctioned an 8 well drilling program at the Espoir field. Due to operational and safety issues with the drilling contractor, the drilling rig was de-mobilized. The Company is seeking a drilling rig and is assessing the opportunity to commence drilling in the latter half of 2014.

The Company has a 57.6% operated interest in the Baobab Field, located in Block CI-40, which is eight kilometers south of the Espoir facilities. Production from the Baobab field commenced in 2005 and the Company carried out a drilling program in 2008 and 2009 to restore production from certain wells shut in due to control of sand and solids production issues. In 2013, there was a temporary shut in of the Baobab field due to a FPSO mooring line failure. Turnaround activities were advanced into this timeframe and production in the Baobab field was reinstated in late January 2014. The Company plans to perform permanent repairs on the mooring lines in March 2014. During 2013, the Company contracted a drilling rig for a 6 well drilling program. The rig is expected to arrive in country no later than the first quarter of 2015.

In 2012, the Company acquired a 36% non-operated working interest in Block CI-514. This block's areal extent is approximately 1,250 square km and the Company believes this block is prospective for deepwater channel/fan plays similar to other discoveries in Ghana and elsewhere offshore Africa. A seismic program has been completed and a drilling rig has been contracted to commence drilling in March 2014.

In 2013, the Company acquired a 60% operated working interest in Block CI-12 which is prospective for deepwater channel/fan structures. The block is located approximately 35km west of the Company's current production at Espoir and Baobab. A 3D seismic program has been completed and the data is currently being processed with potential exploration drilling targeted for 2015.

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Gabon

The Company has a permit comprising a 92% 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. First crude oil production was achieved during the second quarter of 2009 at Platform C and during 2010 on Platform A and B. In mid 2011, production was temporarily suspended as a result of a failure in the mid-water arch. Production was reinstated in mid August 2011. During 2012 a second failure of the mid-water arch occurred. The mid-water arch was stabilized and production was reinstated in late Q1 2013.

South Africa

In May 2012 the Company completed the conversion of its 100% owned natural oil prospecting sub-lease in respect of Block 11B/12B off the south east coast of South Africa into an exploration right for petroleum in respect of this area. During 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for net cash consideration of US\$255 million, including a recovery of US\$14 million of past incurred costs. In the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US\$450 million for a commercial crude oil discovery and US\$120 million for a commercial natural gas discovery.

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Producing and Non Producing Crude Oil and Natural Gas Wells

Set forth below is a summary of the number of wells in which the Company has a working interest that were producing or mechanically capable of producing as of December 31, 2013.

Producing	Natural Gas Wells		Crude Oil Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	13,036.0	10,024.5	9,019.0	8,148.0	22,055.0	18,172.5
British Columbia	1,592.0	1,349.2	218.0	186.2	1,810.0	1,535.4
Saskatchewan	9,831.0	6,904.6	2,676.0	2,190.9	12,507.0	9,095.5
Manitoba	-	-	202.0	198.5	202.0	198.5
Total Canada	24,459.0	18,278.3	12,115.0	10,723.6	36,574.0	29,001.9
United States	1.0	0.1	2.0	0.3	3.0	0.4
North Sea UK Sector	2.0	1.5	72.0	63.5	74.0	65.0
Offshore Africa						
Côte d'Ivoire	-	-	20.0	11.7	20.0	11.7
Gabon	-	-	13.0	12.0	13.0	12.0
Total	24,462.0	18,279.9	12,222.0	10,811.1	36,684.0	29,091.0

Set forth below is a summary of the number of wells in which the Company has a working interest that were not producing or not mechanically capable of producing as of December 31, 2013.

Non Producing	Natural Gas Wells		Crude Oil Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	5,087.0	3,970.9	6,571.0	5,885.3	11,658.0	9,856.2
British Columbia	1,445.0	1,187.6	386.0	317.2	1,831.0	1,504.8
Saskatchewan	1,475.0	1,249.2	2,210.0	1,890.3	3,685.0	3,139.5
Manitoba	2.0	2.0	28.0	26.1	30.0	28.1
Northwest Territories	36.0	20.7	-	-	36.0	20.7
Total Canada	8,045.0	6,430.4	9,195.0	8,118.9	17,240.0	14,549.3
United States	-	-	3.0	0.5	3.0	0.5
North Sea UK Sector	2.0	1.5	46.0	39.4	48.0	40.9
Offshore Africa						
Côte d'Ivoire	-	-	10.0	5.8	10.0	5.8
Gabon	-	-	-	-	-	-
Total	8,047.0	6,431.9	9,254.0	8,164.6	17,301.0	14,596.5

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Properties With Attributed and No Attributed Reserves

The following table summarizes the Company's landholdings as at December 31, 2013.

Region (thousands of acres)	Proved Properties		Unproved Properties		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	%
North America							
Northeast British Columbia	963	807	3,740	2,956	4,703	3,763	80
Northwest Alberta	1,299	1,001	2,887	2,454	4,186	3,455	83
Northern Plains	2,416	2,068	7,833	7,131	10,249	9,199	90
Southern Plains	1,969	1,748	1,281	1,128	3,250	2,876	88
Southeast Saskatchewan	131	120	113	106	244	226	93
Thermal In Situ Oil Sands	84	84	939	838	1,023	922	90
Oil Sands Mining & Upgrading							
	22	22	59	59	81	81	100
Non-core Regions	13	3	1,034	258	1,047	261	25
North America Total	6,897	5,853	17,886	14,930	24,783	20,783	84
International							
North Sea UK Sector	63	55	131	110	194	165	85
Offshore Africa							
Côte d'Ivoire	10	6	671	326	681	332	49
Gabon	-	-	152	140	152	140	92
South Africa	-	-	4,002	2,001	4,002	2,001	50
International Total	73	61	4,956	2,577	5,029	2,638	52
Company Total	6,970	5,914	22,842	17,507	29,812	23,421	79

Where the Company holds interests in different formations under the same surface area pursuant to separate leases, the acreage for each lease is included in the gross and net amounts.

Canadian Natural has approximately 0.8 million net acres attributed to our North America properties which are currently expected to expire by December 31, 2014.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

The Company's unproved property holdings are diverse and located in the North America and International regions. The land assets range from discovery areas where tenure to the property is held indefinitely by hydrocarbon test results or production to exploration areas in the early stages of evaluation. The Company continually reviews the economic viability and ranking of these unproved properties on the basis of product pricing, capital availability and allocation and level of infrastructure development in any specific area. From this process, some properties are scheduled for economic development activities while others are temporarily held inactive, sold, swapped or allowed to expire and relinquished back to the mineral rights owner.

Forward Contracts

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.

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Additional Information Concerning Abandonment and Reclamation Costs

For 2013, the Company's capital expenditures included \$207 million for abandonment expenditures and the Company expects approximately \$558 million of abandonment expenditures to be incurred over the next 3 years. The Company's estimated undiscounted ARO at December 31, 2013 was \$11,867 million and discounted at 10% is approximately \$1,742 million. The Company expects to incur abandonment and reclamation costs on 48,693 net wells.

The abandonment and reclamation costs were not deducted in estimating the Company's future net revenue for December 31, 2014 as the reserve evaluation includes only abandonment costs for future drilling locations that have been assigned reserves.

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine site, upgrading facilities and tailings, and offshore production platforms. Factors that affect costs include number of wells drilled, well depth, facility size and the specific environmental legislation. The estimated future costs are based on engineering estimates of current costs in accordance with present legislation, industry operating practice and the expected timing of abandonment. The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates.

2013 Costs Incurred in Crude Oil, NGLs and Natural Gas Activities

MM\$	North America	North Sea	Offshore Africa	Total
Property Acquisitions				
Proved	250	2	-	252
Unproved	92	-	4	96
Exploration	(2)	-	25	23
Development	6,152	297	97	6,546
	6,492	299	126	6,917
Disposition of 50% interest in South Africa exploration right	-	-	(263)	(263)
Net non-cash costs (1)	126	35	17	178
Costs Incurred	6,618	334	(120)	6,832

(1) Non-cash costs are comprised primarily of changes in asset retirement obligations.

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Exploration and Development Activities

Set forth below are summaries of crude oil, NGLs, and natural gas drilling activities completed by the Company for the fiscal year ended December 31, 2013 by geographic region along with a general discussion of 2013 activity.

		2013 Exploratory Wells					Total
		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	
North America							
Northeast British Columbia							
	Gross	-	1.0	-	-	-	1.0
	Net	-	1.0	-	-	-	1.0
Northwest Alberta							
	Gross	7.0	4.0	2.0	-	-	13.0
	Net	6.0	3.5	2.0	-	-	11.5
Northern Plains							
	Gross	46.0	-	3.0	-	-	49.0
	Net	44.3	-	3.0	-	-	47.3
Southern Plains							
	Gross	-	-	2.0	-	-	2.0
	Net	-	-	2.0	-	-	2.0
Southeast Saskatchewan							
	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Oil Sands Mining and Upgrading							
	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Non-core Regions							
	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
North America Total							
	Gross	53.0	5.0	7.0	-	-	65.0
	Net	50.3	4.5	7.0	-	-	61.8
North Sea UK Sector							
	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Offshore Africa							
	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Company Total							
	Gross	53.0	5.0	7.0	-	-	65.0
	Net	50.3	4.5	7.0	-	-	61.8

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		2013 Development Wells					
		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
North America							
Northeast British Columbia							
	Gross	2.0	28.0	1.0	-	-	31.0
	Net	2.0	27.4	1.0	-	-	30.4
Northwest Alberta							
	Gross	46.0	19.0	2.0	-	-	67.0
	Net	37.4	9.4	2.0	-	-	48.8
Northern Plains							
	Gross	1,026.0	8.0	19.0	28.0	121.0	1,202.0
	Net	976.7	2.7	17.6	28.0	121.0	1,146.0
Southern Plains							
	Gross	26.0	-	2.0	1.0	-	29.0
	Net	26.0	-	2.0	1.0	-	29.0
Southeast Saskatchewan							
	Gross	26.0	-	-	-	-	26.0
	Net	23.5	-	-	-	-	23.5
Oil Sands Mining and Upgrading							
	Gross	-	-	-	9.0	225.0	234.0
	Net	-	-	-	9.0	225.0	234.0
Non-core Regions							
	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
North America Total							
	Gross	1,126.0	55.0	24.0	38.0	346.0	1,589.0
	Net	1,065.6	39.5	22.6	38.0	346.0	1,511.7
North Sea UK Sector							
	Gross	1.0	-	-	-	-	1.0
	Net	1.0	-	-	-	-	1.0
Offshore Africa							
	Gross	-	-	-	-	-	-
	Net	-	-	-	-	-	-
Company Total							
	Gross	1,127.0	55.0	24.0	38.0	346.0	1,590.0
	Net	1,066.6	39.5	22.6	38.0	346.0	1,512.7

Total success rate, excluding service and stratigraphic test wells, for 2013 is 97%.

2014 Crude Oil and Natural Gas Activity

The Company's 2014 guidance as follows does not reflect the potential impact of the agreement announced on February 19, 2014 to acquire certain producing Canadian crude oil and natural gas properties based on a targeted closing date of April 1, 2014.

Drilling activity (number of net wells)	2014 Guidance
Targeting natural gas	61
Targeting crude oil	1,014
Targeting thermal in situ	15
Stratigraphic test / service wells – Exploration and Production	39
Stratigraphic test / service wells – Thermal in situ	184
Stratigraphic test / service wells – Oil Sands Mining and Upgrading	260
Total	1,573

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2014 North America Activity

The 2014 North America natural gas drilling program is highlighted by the continued high-grading of the Company's natural gas asset base. The 2014 North America crude oil drilling program is highlighted by a strong primary heavy crude oil program and continued development of the Pelican Lake and the Primrose thermal projects.

2014 Oil Sands Mining and Upgrading Activity

The Company continues to execute its disciplined strategy of staged expansion and work remains on track. The budgeted project capital expenditures reflect the Board of Directors approval of approximately \$2.5 - \$2.9 billion in targeted strategic expansion.

2014 North Sea Activity

During 2014, the Company is currently targeting to drill wells in the Ninian field in the North Sea.

2014 Offshore Africa Activity

During 2014, the Company is currently targeting to commence drilling wells in the Espoir field in Côte d'Ivoire.

Production Estimates

The following table illustrates the estimated 2014 gross daily proved and probable production reflected in the reserve reports as of December 31, 2013 using forecast prices and costs.

	Light and Medium Crude Oil (bbl/d)	Primary Heavy Crude Oil (bbl/d)	Pelican Lake Heavy Crude Oil (bbl/d)	Bitumen (Thermal Oil) (bbl/d)	Synthetic Crude Oil (bbl/d)	Natural Gas (MMcf/d)	Natural Gas Liquids (bbl/d)	Barrels of Oil Equivalent (BOE/d)
PROVED								
North America	43,843	141,671	47,560	127,518	105,000	1,082	26,443	672,319
North Sea	24,956					14		27,384
Offshore Africa	11,460					25		15,600
Total Proved	80,259	141,671	47,560	127,518	105,000	1,121	26,443	715,303
PROBABLE								
North America	3,132	13,406	1,290	6	4,850	77	3,809	39,255
North Sea	2,616					2		3,032
Offshore Africa	696					-		745
Total Probable	6,444	13,406	1,290	6	4,850	79	3,809	43,032

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Production History

	Q1	Q2	2013 Q3	Q4	Year Ended
North America Production and Netbacks by Product Type (1)					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	42,685	41,612	43,045	45,398	43,192
Netbacks (\$/bbl)					
Sales price (2)	\$80.87	\$88.85	\$100.30	\$80.70	\$87.62
Transportation	2.34	2.62	2.77	2.30	2.50
Royalties	14.02	16.38	18.23	13.72	15.57
Production expenses	21.33	22.73	22.25	20.63	21.71
Netback	\$43.18	\$47.12	\$57.05	\$44.05	\$47.84
Primary Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	133,398	136,071	140,491	134,643	136,166
Netbacks (\$/bbl)					
Sales price (2)	\$51.45	\$71.75	\$89.76	\$61.75	\$69.06
Transportation	2.64	2.71	2.72	2.96	2.76
Royalties	7.17	10.46	16.39	8.24	10.66
Production expenses	16.61	16.50	15.73	16.31	16.28
Netback	\$25.03	\$42.08	\$54.92	\$34.24	\$39.36
Pelican Lake Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	38,020	41,681	45,515	46,084	42,854
Netbacks (\$/bbl)					
Sales price (2)	\$54.41	\$75.17	\$90.32	\$60.19	\$70.62
Transportation	3.13	3.57	3.73	3.20	3.42
Royalties	9.23	10.11	15.40	9.51	11.17
Production expenses	13.47	11.19	9.43	9.25	10.69
Netback	\$28.58	\$50.30	\$61.76	\$38.23	\$45.34
Bitumen (Thermal Oil)					
Average daily production (before royalties) (bbl/d)	108,890	90,051	109,200	78,069	96,503
Netbacks (\$/bbl)					
Sales price (2)	\$50.42	\$65.99	\$86.68	\$57.97	\$66.14
Transportation	2.78	2.09	1.85	0.10	1.81
Royalties	7.27	12.28	16.29	6.51	10.92
Production expenses	10.88	11.75	8.86	13.26	10.97
Netback	\$29.49	\$39.87	\$59.68	\$38.10	\$42.44

SCO

Average daily production (before royalties) (bbl/d)	108,782	67,954	111,959	112,273	100,284
Netbacks (\$/bbl)					
Sales price (2)	\$96.19	\$99.63	\$114.19	\$92.05	\$100.75
Transportation	1.58	1.72	1.52	1.51	1.57
Royalties (3)	3.81	4.41	6.82	5.06	5.11
Production expenses (4)	39.93	44.94	39.90	39.05	40.57
Netback	\$50.87	\$48.56	\$65.95	\$46.43	\$53.50

Natural Gas

Average daily production (before royalties) (MMcf/d)	1,125	1,092	1,136	1,165	1,130
Netbacks (\$/Mcf)					
Sales price (2)	\$3.37	\$3.90	\$3.00	\$3.46	\$3.43
Transportation	0.29	0.29	0.27	0.28	0.29
Royalties	0.09	0.25	0.06	0.17	0.14
Production expenses	1.52	1.38	1.33	1.32	1.39
Netback	\$1.47	\$1.98	\$1.34	\$1.69	\$1.61

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Production History

	Q1	Q2	2013 Q3	Q4	Year Ended
Natural Gas Liquids					
Average daily production (before royalties) (bbl/d)	22,496	22,038	27,278	28,037	24,984
Netbacks (\$/bbl)					
Sales price (2)	\$60.29	\$57.93	\$55.95	\$55.07	\$57.10
Transportation	0.41	1.17	1.13	1.32	1.03
Royalties	12.78	12.73	5.54	6.92	9.12
Production expenses	9.70	9.33	7.75	7.57	8.48
Netback	\$37.40	\$34.70	\$41.53	\$39.26	\$38.47

North Sea Production and Netbacks by Product Type (1)

Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	18,774	18,901	15,522	20,155	18,334
Netbacks (\$/bbl)					
Sales price (2)	\$114.28	104.47	\$117.30	\$113.84	\$112.46
Transportation	1.05	0.63	0.84	0.57	0.75
Royalties	0.41	0.34	0.31	0.28	0.33
Production expenses	74.65	47.85	78.66	65.41	66.19
Netback	\$38.17	\$55.65	\$37.49	\$47.58	\$45.19

Natural Gas

Average daily production (before royalties) (MMcf/d)	1	4	4	7	4
Netbacks (\$/Mcf)					
Sales price (2)	\$3.65	\$7.03	\$6.12	\$5.05	\$5.69
Transportation	1.13	0.34	0.33	0.23	0.36
Royalties	-	-	-	-	-
Production Expenses	3.77	3.53	5.79	4.81	4.67
Netback	\$(1.25)	\$3.16	\$0.00	\$0.01	\$0.66

Offshore Africa Production and Netbacks by Product Type (1)

Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	16,112	18,055	16,172	13,379	15,923
Netbacks (\$/bbl)					
Sales price (2)	\$113.70	\$107.71	\$119.48	\$108.25	\$110.21
Transportation	-	-	-	-	-
Royalties	17.71	18.38	30.83	16.41	18.18
Production expenses	25.72	17.98	25.13	29.31	25.32
Netback	\$70.27	\$71.35	\$63.52	\$62.53	\$66.71

Natural Gas

Average daily production

(before royalties) (MMcf/d)

24

26

23

23

24

Netbacks (\$/Mcf)

Sales price (2)

\$10.24

\$10.02

\$10.47

\$11.13

\$10.45

Transportation

0.14

0.14

0.15

0.15

0.14

Royalties

1.57

1.68

2.06

2.04

1.83

Production expenses

2.24

2.34

2.82

2.73

2.53

Netback

\$6.29

\$5.86

\$5.44

\$6.21

\$5.95

- (1) Amounts expressed on a per unit basis are based on sales volumes.
- (2) Net of blending costs and excluding risk management activities.
- (3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.
- (4) Adjusted cash production costs on a per unit basis are based on sales volumes excluding the period of turnaround/suspension of production.

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SELECTED FINANCIAL INFORMATION

(MM\$, except per common share information)	Year Ended December 31	
	2013	2012
Product sales	\$ 17,945	\$ 16,195
Net earnings	\$ 2,270	\$ 1,892
Per common share		
– basic	\$ 2.08	\$ 1.72
– diluted	\$ 2.08	\$ 1.72
Adjusted net earnings from operations (1)	\$ 2,435	\$ 1,618
Per common share		
– basic	\$ 2.24	\$ 1.48
– diluted	\$ 2.23	\$ 1.47
Cash flow from operations (1)	\$ 7,477	\$ 6,013
Per common share		
– basic	\$ 6.87	\$ 5.48
– diluted	\$ 6.86	\$ 5.47
Dividends declared per common share	\$ 0.575	\$ 0.42
Total assets	\$ 51,754	\$ 48,980
Total long-term liabilities	\$ 20,748	\$ 20,721
Capital expenditures, net of dispositions	\$ 7,274	\$ 6,308

(1) These non-GAAP measures are reconciled to net earnings as determined in accordance with IFRS in the “Net Earnings and Cash Flow from Operations” section of the Company’s MD&A which is incorporated by reference into this document.

DIVIDEND HISTORY

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 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.

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.

	2013	2012	2011
Cash dividends declared per common share	\$0.575	\$0.42	\$0.36

In March 2013 the Company’s Board of Directors increased the cash dividend on common shares, approving a 20% increase in the quarterly dividend from \$0.105 per common share to \$0.125 per common share effective with the April 1, 2013 payment. The Board further increased the quarterly dividend to \$0.20 per common share, an 80% increase, beginning with the January 1, 2014 payment with a subsequent increase of 12.5% to \$0.225 per common share quarterly commencing with the April 1, 2014 payment.

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DESCRIPTION OF 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. The Company is authorized to issue an unlimited number of Preferred Shares issuable in one or more series. The directors of the Company are authorized to fix, before the issue thereof, the number of shares in each series and to determine the designation, rights, privileges, restrictions and conditions attaching to the Preferred Shares of each series.

Credit Ratings

The following information relating to the Company's credit ratings is provided as it relates to the Company's financing costs, liquidity and operations. Specifically, credit ratings affect the Company's ability to obtain short-term and long-term financing and the cost of such financing. A reduction in the current rating on the Company's debt by its rating agencies (particularly a reduction below investment grade ratings), or a negative change to the Company's ratings outlook could adversely affect the Company's cost of financing and its access to sources of liquidity and capital. In addition, changes to credit ratings may affect the Company's ability to, and the associated costs of, entering into ordinary course derivative or hedging transactions and entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

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 on the current 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, the Company is under no obligation to update this Annual Information Form.

	Senior Unsecured Debt Securities	Commercial Paper	Outlook/Trend
Moody's Investors Service Inc. ("Moody's")	Baa1	P-2	Stable
Standard & Poor's Rating Services ("S&P") (1)	BBB+	A-2	Stable
DBRS Limited ("DBRS")	BBB (high)	-	Stable

(1) S&P assigns a rating outlook to Canadian Natural and not to individual long-term debt instruments.

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 Baa by Moody's is within the fourth highest of nine categories and is assigned to obligations that are judged to be medium-grade and are subject to moderate credit risk. Such securities may possess certain speculative characteristics. Moody's applies numerical modifiers 1, 2 and 3 to 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 rating direction over the medium term. Moody's credit ratings on commercial paper are on a short-term debt rating scale that ranges from P-1 to NP, representing the range of such securities rated from highest to lowest quality. A rating of P-2 by Moody's is the second highest of four categories and indicates a strong ability to repay short-term obligations.

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

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outlook, consideration is given to any changes in the economic and/or fundamental business conditions. S&P credit ratings on commercial paper are on a short-term debt rating scale that ranges from A-1 to D, representing the range of such securities rated from highest to lowest quality. A rating of A-2 by S&P is the second highest of seven categories and indicates that the obligor is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rating categories, but the obligor's capacity to meet its financial commitment on these obligations is satisfactory.

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. The capacity for the payment of financial obligations is considered acceptable, though may be vulnerable to future events. All rating categories other than AAA and D also contain subcategories "(high)" and "(low)" which indicate the relative standing within such rating category. The rating trend is DBRS' opinion regarding the outlook for the rating.

Canadian Natural has made payments to Moody's, S&P and DBRS in connection with the assignment of ratings to our long-term and short-term debt and will make payments to Moody's, S&P and DBRS in connection with the confirmation of such ratings for purposes of the offering of debt securities from time to time. Canadian Natural has made payments to an affiliate of Moody's in the last 2 years for subscription to use its online credit analytical tools.

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. Set forth below is the trading activity of the Company's common shares on the TSX in 2013.

2013 Monthly Historical Trading on TSX

Month	High	Low	Close	Volume Traded
January	\$31.64	28.66	30.12	62,999,864
February	\$31.81	29.77	31.52	43,708,251
March	\$33.91	30.47	32.57	72,335,362
April	\$32.86	29.21	29.55	72,121,949
May	\$32.43	28.78	30.90	58,227,267
June	\$30.79	28.44	29.65	53,649,679
July	\$34.64	29.72	31.83	102,209,869
August	\$33.05	30.45	32.14	39,785,610
September	\$33.10	31.94	32.37	35,219,682
October	\$34.05	31.73	33.09	43,827,749
November	\$35.55	31.92	34.58	50,996,457
December	\$36.04	33.67	35.94	47,921,695

During 2013, the Company purchased 10,164,800 common shares under a Normal Course Issuer Bid at a weighted average purchase price of \$31.46 per common share for a total cost of approximately \$320 million.

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DIRECTORS AND OFFICERS

The names, municipalities of residence, offices held with the Company and principal occupations of the Directors and Officers of the Company for the 5 preceding years, are set forth below. Further detail on the Directors and Named Executive Officers are found in the Company's Information Circular dated March 19, 2014 incorporated herein by reference.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Catherine M. Best, FCA, ICD.D Calgary, Alberta Canada	Director (1)(2) (age 60)	Corporate director. She has served continuously as a director of the Company since November 2003 and is currently serving on the board of directors of Superior Plus Corporation, Aston Hill Financial Inc. and AltaGas Ltd. She is also a member of the Board of the Alberta Children's Hospital Foundation, The Calgary Foundation, The Wawanesa Mutual Insurance Company and serves as a volunteer member of the Audit Committee of the Calgary Stampede and of the Audit Committee of the University of Calgary.
N. Murray Edwards Calgary/Banff, Alberta Canada	Chairman and Director (5) (age 54)	President, Edco Financial Holdings Ltd. (private management and consulting company). He 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.
Timothy W. Faithfull Oxford, England	Director (1)(3) (age 69)	Independent businessman and corporate director. He has served continuously as a director of the Company since November 2010. He is Chairman of the Starehe Endowment Fund in the UK and a Council Member of the Canada – UK Colloquia and is currently serving on the board of directors of TransAlta Corporation, AMEC plc, ICE Futures Europe, LIFFE Administration and Management and Shell Pension Trust Limited, a private pension trust.
Honourable Gary A. Filmon, P.C., O.C., O.M. Winnipeg, Manitoba Canada	Director (1)(4) (age 71)	Corporate director. He has served continuously as a director of the Company since February 2006 and is currently serving on the board of directors of MTS Allstream Inc., Arctic Glacier Income Trust, and Exchange Income Corporation.
Christopher L. Fong Calgary, Alberta Canada	Director (3)(5) (age 64)	Corporate director. Until his retirement in May 2009 he was Global Head, Corporate Banking, Energy with RBC Capital Markets. He has served continuously as a director of the Company since November 2010. He was

appointed Advisor to the Alberta's Department of Energy's Competitive Review process in 2009. He is currently serving on the board of directors of Anderson Energy Ltd., Computer Modelling Group Ltd. and sits on the Petroleum Advisory Committee of the Alberta Securities Commission.

Ambassador Gordon D. Giffin
Atlanta, Georgia
USA

Director (1)(4)
(age 64)

Senior Partner, McKenna Long & Aldridge LLP (law firm) since May 2001. He 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, Element Financial Corporation, Just Energy Corp., and TransAlta Corporation.

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Name	Position Presently Held	Principal Occupation During Past 5 Years
Wilfred A. Gobert Calgary, Alberta Canada	Director (2)(4)(5) (age 66)	Independent businessman. He has served continuously as a director since November 2010. He is currently serving on the board of directors of Gluskin Sheff & Associates, Trilog Energy Corp., and Manitek Energy Inc.
Steve W. Laut Calgary, Alberta Canada	President and Director (3) (age 56)	Officer of the Company. He has served continuously as a director of the Company since August 2006.
Keith A.J. MacPhail Calgary, Alberta Canada	Director (3)(5) (age 57)	Executive Chairman of Bonavista Energy Corporation since November 2012 and prior thereto, Chairman and CEO of Bonavista since 1997. He is also Chairman of NuVista Energy Ltd. since July 2003. He has served continuously as a director of the Company since October 1993. He is currently serving on the board of directors of Bonavista Energy Corporation and NuVista Energy Ltd.
Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C. Cap Pelé, New Brunswick Canada	Director (2)(4) (age 66)	Deputy Chair, TD Bank Group (financial services). 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.
Dr. Eldon R. Smith, O.C., M.D. Calgary, Alberta Canada	Director (2)(3) (age 74)	President of Eldon R. Smith & Associates Ltd., (a private health care consulting company) since 2001, and is Emeritus Professor of Medicine and Former Dean, Faculty of Medicine, University of Calgary. He has served continuously as a director of the Company since May 1997. Currently serving on the board of directors of Intellipharma International Inc., Resverlogix Corp., and Aston Hill Financial Inc.
David A. Tuer Calgary, Alberta Canada	Director (1)(5) (age 64)	Vice-Chairman and Chief Executive Officer of Teine Energy Ltd. (private oil and gas exploration company) and served as Vice-Chairman and Chief Executive Officer of Marble Point Energy Ltd. the predecessor to Teine Energy Ltd. also a private oil and gas exploration company from 2008 to 2010. Prior thereto he was Chairman, Calgary Health Region from 2001 to 2008 and Executive Vice-Chairman BA Energy Inc. from 2005 to 2008 when it was acquired by its parent company Value Creation Inc. through a Plan of Arrangement. He has served continuously as a director of the Company since May 2002. Currently serving on the board of directors of Altalink Management LLP., a

private limited partnership.

Jeffrey J. Bergeson
Calgary, Alberta
Canada

Vice-President,
Exploitation West
(age 57)

Officer of the Company.

Corey B. Bieber
Calgary, Alberta
Canada

Chief Financial Officer
and Senior
Vice-President,
Finance
(age 50)

Officer of the Company.

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Name	Position Presently Held	Principal Occupation During Past 5 Years
Bryan C. Bradley Calgary, Alberta Canada	Vice-President, Marketing (age 48)	Officer of the Company since November 2011; prior thereto Manager Crude Oil Marketing from November 2006 to November 2011.
Mary-Jo E. Case Calgary, Alberta Canada	Senior Vice-President, Land & Human Resources (age 55)	Officer of the Company.
Michael A. Catley Calgary, Alberta Canada	Vice-President, Conventional and Thermal Field Operations (age 53)	Officer of the Company since January 29, 2013; prior thereto Manager, Eastern Operations from October 2006 to October 2010; Vice-President, Bitumen Production from October 2010 to April 2011; Director, Supply Management Operations from April 2011 to June 2012 and most recently Director, Field Operations Eastern and Thermal from June 2012 to January 2013.
William R. Clapperton Calgary, Alberta Canada	Vice-President, Regulatory, Stakeholder and Environmental Affairs (age 51)	Officer of the Company.
James F. Corson Calgary, Alberta Canada	Vice-President, Human Resources & Labour Relations (age 63)	Officer of the Company.
Réal M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 63)	Officer of the Company.
Randall S. Davis Calgary, Alberta Canada	Vice-President, Finance & Accounting (age 47)	Officer of the Company.
Réal J. H. Doucet Calgary, Alberta Canada	Senior Vice-President, Horizon Projects (age 61)	Officer of the Company.
Darren M. Fichter Calgary, Alberta Canada	Vice-President, Exploitation, East (age 43)	Officer of the Company since January 2012; prior thereto Manager, Heavy Oil South April 2004 to June 2009 and most recently Vice-President, Exploitation of CNR International (U.K.) Limited, a wholly owned subsidiary of the Company, from June 2009 to January 2012.

Allan E. Frankiw
Calgary, Alberta
Canada

Vice-President,
Production, East
(age 57)

Officer of the Company.

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Name	Position Presently Held	Principal Occupation During Past 5 Years
Jay Froc Calgary, Alberta Canada	Vice-President, Infrastructure, Logistics and Project Controls (age 48)	Officer of the Company since June 2013. Most recently held various positions with Suncor Energy Inc. since 2006.
Douglas A. Gardener Calgary, Alberta Canada	Vice-President, Exploration, Central (age 62)	Officer of the Company since January 2012; prior thereto Chief Geologist with the Company from December 2006 to January 2012.
Dean W. Halewich Calgary, Alberta Canada	Vice-President, Facilities and Pipelines (age 46)	Officer of the Company since September 2011; prior thereto Manager, Facilities Engineering from February 2002 to May 2011 and most recently Manager, Thermal Projects from May 2011 to September 2011.
Timothy J. Hamilton Calgary, Alberta Canada	Vice-President, Production, West (age 58)	Officer of the Company since February 2010; prior thereto Manager Production, British Columbia South from January 2007 to September 2009 and most recently Manager Production, British Columbia from September 2009 to February 2010.
Murray G. Harris Calgary, Alberta Canada	Vice-President, Financial Controller and Horizon Accounting (age 50)	Officer of the Company since March 2012; prior thereto Financial Controller from June 2005 to March 2012.
David B. Holt Calgary, Alberta Canada	Vice-President, Production, Central (age 48)	Officer of the Company since September 2011; prior thereto Production Manager, Heavy Oil North from January 2003 to September 2011 and most recently Vice-President, Production West from September 2011 to January 2012.
John A. Howard Calgary, Alberta Canada	Vice-President, Thermal Production (age 55)	Officer of the Company since September 2011; prior thereto Project Manager, Bitumen Upgrading from May 2006 to May 2007; Manager, Deep Basin Production from May 2007 to October 2009 and most recently Manager, SAGD Production from October 2009 to September 2011.
Peter J. Janson Calgary, Alberta Canada	Senior Vice-President, Horizon Operations (age 56)	Officer of the Company.
Terry J. Jocksch Calgary, Alberta Canada	Senior Vice-President, Thermal (age 46)	Officer of the Company.

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Pamela A. Jones
Calgary, Alberta
Canada

Vice-President,
Safety and Asset
Integrity
(age 51)

Officer of the Company since May 2011; prior thereto
Project Integration Manager from July 2007 to January
2011 and most recently Manager, Special Projects
Assets from January 2011 to May 2011.

Philip A. Keele
Calgary, Alberta
Canada

Vice-President,
Mining
(age 54)

Officer of the Company.

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Name	Position Presently Held	Principal Occupation During Past 5 Years
Allen M. Knight Calgary, Alberta Canada	Senior Vice-President, International & Corporate Development (age 64)	Officer of the Company.
Kevin Kowbel Calgary, Alberta Canada	Vice-President, Drilling and Completions (age 43)	Officer of the Company since January 2012; prior thereto Drilling Manager from April 2006 to January 2012.
Ronald K. Laing Calgary, Alberta Canada	Vice-President, Commercial Operations (age 44)	Officer of the Company.
Bruce E. McGrath Calgary, Alberta Canada	Corporate Secretary (age 64)	Officer of the Company.
Tim S. McKay Calgary, Alberta Canada	Executive Vice President, Chief Operating Officer (age 52)	Officer of the Company.
Casey D. McWhan Calgary, Alberta Canada	Vice-President, Bitumen Production (age 51)	Officer of the Company since November 2011; prior thereto President, Modec du Brasil from January 2006 to September 2008; Senior Vice-President, Prosafe Production from September 2008 to January 2010 and most recently Continuous Process Improvement Lead with the Company from April 2010 to November 2011.
Paul M. Mendes Calgary, Alberta Canada	Vice-President, Legal and General Counsel (age 48)	Officer of the Company since February 2010; prior thereto Director, Legal Services, Horizon from January 2007 to February 2010.
Leon Miura Calgary, Alberta Canada	Vice-President, Horizon Downstream Projects (age 59)	Officer of the Company.
S. John Parr Calgary, Alberta Canada	Vice-President, Thermal Projects (age 53)	Officer of the Company.
David A. Payne Calgary, Alberta	Vice-President, Exploitation, Central	Officer of the Company.

Canada

(age 52)

Canadian Natural Resources Limited

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Name	Position Presently Held	Principal Occupation During Past 5 Years
William R. Peterson Calgary, Alberta Canada	Senior Vice-President, Production and Development Operations (age 47)	Officer of the Company.
Douglas A. Proll Calgary, Alberta Canada	Executive Vice-President (age 63)	Officer of the Company.
David W. Reed Calgary, Alberta Canada	Vice-President, Horizon Upgrading & Utilities (age 64)	Officer of the Company since August 2012; prior thereto Vice-President Tesoro Corporation from May 2007 to November 2011.
Joy P. Romero Calgary, Alberta Canada	Vice-President, Technology Development (age 57)	Officer of the Company.
Sheldon L. Schroeder Fort McMurray, Alberta Canada	Vice-President, Horizon Upstream Projects (age 46)	Officer of the Company.
Kendall W. Stagg Calgary, Alberta Canada	Vice-President, Exploration, West (age 52)	Officer of the Company.
Scott G. Stauth Calgary, Alberta Canada	Senior Vice-President, North American Operations (age 48)	Officer of the Company.
Lyle G. Stevens Calgary, Alberta Canada	Executive Vice-President, Canadian Conventional (age 59)	Officer of the Company.
Stephen C. Suche Calgary, Alberta Canada	Vice-President, Information and Corporate Services (age 54)	Officer of the Company.
Domenic Torriero Calgary, Alberta	Vice-President, Exploration, East	Officer of the Company.

Canada (age 49)

Grant M. Williams Vice-President, Officer of the Company.
Calgary, Alberta Thermal Exploration
Canada (age 56)

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Canadian Natural Resources Limited

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Name	Position Presently Held	Principal Occupation During Past 5 Years
Jeffrey W. Wilson Calgary, Alberta Canada	Senior Vice-President, Exploration (age 61)	Officer of the Company.
Betty Yee Calgary, Alberta Canada	Vice-President, Land (age 49)	Officer of the Company since June 2013. Most recently was Manager of Acquisition and Divestments of the Company since 2003.
Daryl G. Youck Calgary, Alberta Canada	Vice-President, Thermal Exploitation (age 45)	Officer of the Company.
(1)		Member of the Audit Committee.
(2)		Member of the Compensation Committee.
(3)		Member of the Health, Safety, and Environmental Committee.
(4)		Member of the Nominating, Governance and Risk Committee.
(5)		Member of the Reserves 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 and General Meeting of Shareholders held on May 2, 2013.

As at December 31, 2013, the directors and executive officers of the Company, as a group, beneficially owned or controlled or directed, directly or indirectly, in the aggregate, approximately 3% of the total outstanding common shares (approximately 4% after the exercise of options held by them pursuant to the Company's stock option plan).

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).

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

From time to time, Canadian Natural is the subject of litigation arising out of the Company's normal course of operations. Damages claimed under such litigation may be material 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.

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.

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 Investor Services LLC in the city of New York. The registers for transfers of the Company's common shares are maintained by Computershare Trust Company of Canada.

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.

Canadian Natural Resources Limited

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INTERESTS OF EXPERTS

The Company's auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditors' report dated March 5, 2014 in respect of the Company's consolidated financial statements as at December 31, 2013, December 31, 2012, and for each of the three years in the period ended December 31, 2013 and the Company's internal control over financial reporting as at December 31, 2013. 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, Sproule International 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.

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, T.W. Faithfull, 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. All of the members of the Corporation's Audit Committee are financially literate. 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. Ms. C. M. Best who is chair of the Audit Committee qualifies as an "audit committee financial expert" under the rules issued by the SEC pursuant to the requirements of the Sarbanes Oxley Act of 2002.

Mr. T. W. Faithfull holds a Master of Arts from the University of Oxford (Philosophy, Politics and Economics) and is an alumnus of the London Business School. As Chief Executive Officer of Shell Canada Limited and in his other capacities during his 36 years with the Royal Dutch/Shell group of companies, together with his experience as an audit committee member of other publicly traded companies, he has acquired significant financial experience and exposure to complex accounting and financial issues and an understanding of audit committee functions.

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.

Ambassador G. D. Giffin's education and experience relevant to the performance of his responsibilities as an audit committee member is derived from a law practice of over thirty years 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.

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Auditor Service Fees

The Audit Committee of the Board of Directors in 2013 approved specified audit and non-audit services to be performed by PricewaterhouseCoopers LLP (“PwC”). The services provided include: (i) the annual audit of the Company's consolidated financial statements and internal controls over financial reporting, reviews of the Company's quarterly unaudited consolidated financial statements, audits of certain of the Company's subsidiary companies' annual financial statements as well as other audit services provided in connection with statutory and regulatory filings; (ii) audit related services including pension assets and Crown Royalty Statements; (iii) tax services related to expatriate personal tax and compliance and other corporate tax return matters; and (iv) non-audit services related to expatriate visa application assistance and to accessing resource materials through PwC's accounting literature library.

Fees accrued to PwC are shown in the table below.

Auditor service (000's)	2013	2012
Audit fees	\$3,032	\$2,723
Audit related fees	212	183
Tax fees	478	481
All other fees	73	9
	\$3,795	\$3,396

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

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 General Meeting and Information Circular dated March 19, 2014 in connection with the Annual and Special Meeting of Shareholders of Canadian Natural to be held on May 8, 2014 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's Discussion and Analysis, comparative Consolidated Financial Statements and Supplementary Oil & Gas Information for the most recently completed fiscal year ended December 31, 2013 found on pages 18 to 54, 55 to 91 and 92 to 99 respectively, of the 2013 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

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SCHEDULE "A"

FORM 51-101F2

REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Report on Reserves Data

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

1. We have evaluated and reviewed the Corporation's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.
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 and review.

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

3. Those standards require that we plan and perform an evaluation and review to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation and review also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated and reviewed by us for the year ended December 31, 2013 and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the Corporation's management and board of directors:

Net Present Value of Future Net Revenue
(Before Income Taxes, 10% Discount Rate) (\$ millions)

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation/Review Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate) (\$ millions)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	Sproule evaluated the P&NG Reserves February 3, 2014	Canada and USA	\$0	\$45,113	\$309	\$45,422
Sproule International Limited	Sproule evaluated the P&NG Reserves February 3, 2014	United Kingdom and Offshore	\$0	\$12,162	\$0	\$12,162

		Africa				
GLJ Petroleum Consultants Ltd.	GLJ evaluated the oil sands mining properties February 3, 2014	Canada				
			\$0	\$27,209	\$0	\$27,209
Totals			\$0	\$84,484	\$309	\$84,793

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, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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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.

Executed as to our report(s) referred to above:

Sproule Associates Limited
Calgary, Alberta, Canada,
March 5, 2014

Sproule International Limited
Calgary, Alberta, Canada,
March 5, 2014

Original Signed By

SIGNED "HARRY J. HELWERDA"
Harry J. Helwerda, P.Eng., FEC, FGC
(Hon.)
President, Chief Operating Officer and
Director

Original Signed By

SIGNED "HARRY J. HELWERDA"
Harry J. Helwerda, P.Eng., FEC, FGC
(Hon.)
President, Chief Operating Officer and
Director

Original Signed By

SIGNED "NORA T. STEWART"
Nora T. Stewart, P.Eng.
Vice-President, Canada and Partner

Original Signed By

SIGNED "SCOTT W. PENNELL"
Scott W. Pennell, P.Eng.
Manager, Engineering and Director

Original Signed By

SIGNED "CAMERON P. SIX"
Cameron P. Six, P.Eng.
Vice-President, Unconventional and
Director

Original Signed By

SIGNED "GREG D. ROBINSON"
Greg D. Robinson, P.Eng.
Vice-President, International and
Director

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada,
March 5, 2014

Original Signed By

SIGNED "CARALYN P. BENNETT"
Caralyn P. Bennett, P.Eng.
Vice-President

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SCHEDULE "B"

FORM 51-101F3

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 and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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

The Reserves Committee of the Board of Directors of the Corporation has:

- (a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluators;
- (b) met with 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
- (c) reviewed the reserves data with management and the independent qualified reserves evaluators.

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

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

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Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Original Signed By:

SIGNED "STEVE W. LAUT"

Steve W. Laut
President

Original Signed By:

SIGNED "COREY B. BIEBER"

Corey B. Bieber
Chief Financial Officer and Senior
Vice President, Finance

Original Signed By:

SIGNED "DAVID A TUER"

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

Original Signed By:

SIGNED "WILFRED A. GOBERT"

Wilfred A. Gobert
Independent Director and Member of
the Reserve Committee

Dated this 5th day of March, 2014

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SCHEDULE “C”

CANADIAN NATURAL RESOURCES LIMITED
 (“the Corporation”)
 Charter of the Audit Committee of the Board of Directors

I Audit Committee Purpose

The Audit Committee is appointed by the Board of Directors (the “Board”) to assist the Board in fulfilling its responsibility for the stewardship of the Corporation in overseeing the business and affairs of the Corporation. 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 and review 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.

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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;

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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.

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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.

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Management's Report

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

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

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

- the Company's consolidated financial statements as at and for the year ended December 31, 2013; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2013.

Their report is presented with the consolidated financial statements.

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

(signed) "Steve W. Laut"
Steve W. Laut
President

(signed) "Corey B. Bieber"
Corey B. Bieber, CA
Chief Financial Officer &
Senior Vice-President, Finance

(signed) "Murray G. Harris"
Murray G. Harris, CA
Vice-President, Financial
Controller &
Horizon Accounting

Calgary, Alberta, Canada
March 5, 2014

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Management's Assessment of Internal Control Over Financial Reporting

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

Management, including the Company's President and the Company's Chief Financial Officer and Senior Vice-President, Finance, performed an assessment of the Company's internal control over financial reporting based on the criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on the assessment, management has concluded that the Company's internal control over financial reporting is effective as at December 31, 2013. Management recognizes that all internal control systems have inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has provided an opinion on the Company's internal control over financial reporting as at December 31, 2013, as stated in their Auditor's Report.

(signed) "Steve W. Laut"

Steve W. Laut
President

(signed) "Corey B. Bieber"

Corey B. Bieber, CA
Chief Financial Officer
&
Senior Vice-President,
Finance

Calgary, Alberta, Canada
March 5, 2014

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Independent Auditor's Report

To the Shareholders of
Canadian Natural Resources Limited

We have completed integrated audits of Canadian Natural Resources Limited's 2013, 2012 and 2011 consolidated financial statements and its internal control over financial reporting as at December 31, 2013. Our opinions, based on our audits are presented below.

Report on the consolidated financial statements

We have audited the accompanying consolidated financial statements of Canadian Natural Resources Limited, which comprise the consolidated balance sheets as at December 31, 2013 and December 31, 2012 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2013, and the related notes.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards also require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Canadian Natural Resources Limited as at December 31, 2013 and December 31, 2012 and its financial performance and its cash flows for each of the three years in the period ended December 31, 2013 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on internal control over financial reporting

We have also audited Canadian Natural Resources Limited's internal control over financial reporting as at December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992), issued by the Committee of

Sponsoring Organizations of the Treadway Commission (COSO).

Management's responsibility for internal control over financial reporting

Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report.

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Auditor's responsibility

Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on Canadian Natural Resources Limited's internal control over financial reporting.

Definition of internal control over financial reporting

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

Inherent limitations

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

Opinion

In our opinion, Canadian Natural Resources Limited maintained, in all material respects, effective internal control over financial reporting as at December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by COSO.

/s/ PricewaterhouseCoopers
LLP

Chartered Accountants

Calgary, Alberta, Canada
March 5, 2014

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Consolidated Balance Sheets

As at December 31

(millions of Canadian dollars)

	Note	2013	2012
ASSETS			
Current assets			
Cash and cash equivalents		\$16	\$37
Accounts receivable		1,427	1,197
Inventory	5	632	554
Prepays and other		141	126
		2,216	1,914
Exploration and evaluation assets	6	2,609	2,611
Property, plant and equipment	7	46,487	44,028
Other long-term assets	8	442	427
		\$51,754	\$48,980
LIABILITIES			
Current liabilities			
Accounts payable		\$637	\$465
Accrued liabilities		2,519	2,273
Current income taxes		359	285
Current portion of long-term debt	9	1,444	798
Current portion of other long-term liabilities	10	275	155
		5,234	3,976
Long-term debt	9	8,217	7,938
Other long-term liabilities	10	4,348	4,609
Deferred income taxes	12	8,183	8,174
		25,982	24,697
SHAREHOLDERS' EQUITY			
Share capital	13	3,854	3,709
Retained earnings		21,876	20,516
Accumulated other comprehensive income	14	42	58
		25,772	24,283
		\$51,754	\$48,980

Commitments and contingencies (note 19)

Approved by the Board of Directors on March 5, 2014

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

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

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Consolidated Statements of Earnings

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

	Note	2013	2012	2011
Product sales		\$ 17,945	\$ 16,195	\$ 15,507
Less: royalties		(1,800)	(1,606)	(1,715)
Revenue		16,145	14,589	13,792
Expenses				
Production		4,559	4,249	3,671
Transportation and blending		2,938	2,752	2,327
Depletion, depreciation and amortization	7	4,844	4,328	3,604
Administration		335	270	235
Share-based compensation	10	135	(214)	(102)
Asset retirement obligation accretion	10	171	151	130
Interest and other financing expense	17	279	364	373
Risk management activities	18	(77)	120	(27)
Foreign exchange loss (gain)		210	(49)	1
Horizon asset impairment provision	11	–	–	396
Insurance recovery – property damage	11	–	–	(393)
Insurance recovery – business interruption	11	–	–	(333)
Gain on corporate acquisition/disposition of properties	6,7	(289)	–	–
Equity loss from joint venture	8	4	9	–
		13,109	11,980	9,882
Earnings before taxes		3,036	2,609	3,910
Current income tax expense	12	735	747	860
Deferred income tax expense (recovery)	12	31	(30)	407
Net earnings		\$ 2,270	\$ 1,892	\$ 2,643
Net earnings per common share				
Basic	16	\$ 2.08	\$ 1.72	\$ 2.41
Diluted	16	\$ 2.08	\$ 1.72	\$ 2.40

Consolidated Statements of Comprehensive Income

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

	2013	2012	2011
Net earnings	\$ 2,270	\$ 1,892	\$ 2,643
Items that may be reclassified subsequently to net earnings			
Net change in derivative financial instruments designated as cash flow hedges			
Unrealized (loss) income, net of taxes of \$nil (2012 – \$4 million, 2011 – \$5 million)	(4)	31	(23)
Reclassification to net earnings, net of taxes of \$nil (2012 – \$nil, 2011 – \$17 million)	(1)	(7)	52
	(5)	24	29
Foreign currency translation adjustment			
Translation of net investment	(11)	8	(12)

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Other comprehensive (loss) income, net of taxes	(16)	32	17
Comprehensive income	\$2,254		\$1,924	\$2,660

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Consolidated Statements of Changes in Equity

For the years ended December 31

(millions of Canadian dollars)

	Note	2013	2012	2011
Share capital	13			
Balance – beginning of year		\$3,709	\$3,507	\$3,147
Issued upon exercise of stock options		130	194	255
Previously recognized liability on stock options exercised for common shares		50	45	115
Purchase of common shares under Normal Course Issuer Bid		(35)	(37)	(10)
Balance – end of year		3,854	3,709	3,507
Retained earnings				
Balance – beginning of year		20,516	19,365	17,212
Net earnings		2,270	1,892	2,643
Purchase of common shares under Normal Course Issuer Bid	13	(285)	(281)	(94)
Dividends on common shares	13	(625)	(460)	(396)
Balance – end of year		21,876	20,516	19,365
Accumulated other comprehensive income	14			
Balance – beginning of year		58	26	9
Other comprehensive (loss) income, net of taxes		(16)	32	17
Balance – end of year		42	58	26
Shareholders' equity		\$25,772	\$24,283	\$22,898

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Consolidated Statements of Cash Flows

For the years ended December 31

(millions of Canadian dollars)

	Note	2013	2012	2011
Operating activities				
Net earnings		\$ 2,270	\$ 1,892	\$ 2,643
Non-cash items				
Depletion, depreciation and amortization		4,844	4,328	3,604
Share-based compensation		135	(214)	(102)
Asset retirement obligation accretion		171	151	130
Unrealized risk management loss (gain)		39	(42)	(128)
Unrealized foreign exchange loss		226	129	215
Realized foreign exchange gain on repayment of US dollar debt securities		(12)	(210)	(225)
Equity loss from joint venture		4	9	