

CANADIAN NATURAL RESOURCES LTD  
Form 40-F  
March 25, 2015

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, 2014

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))

2100, 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.

1,091,836,851 Common Shares outstanding as of December 31, 2014

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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. On March 24, 2015 the reported Bank of Canada noon rate for one Canadian dollar was US\$0.7993. On March 24, 2015 the reported Bank of Canada noon rate for one U. S. dollar was C\$1.2511.

#### 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, 2014.

B. Audited Annual Financial Statements

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2014 and 2013, 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, 2014.

#### Supplementary Oil & Gas Information

For Canadian Natural's Supplementary Oil & Gas Information for the year ended December 31, 2014, see Exhibit 99.1 to this Annual Report on Form 40-F.

ANNUAL INFORMATION FORM  
FOR THE YEAR ENDED DECEMBER 31, 2014

March 25, 2015

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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	barrel
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 <sub>2</sub>	Carbon dioxide
CO <sub>2</sub> e	Carbon dioxide equivalents
Crude oil, natural gas and NGLs	The Company’s light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, synthetic crude oil, bitumen (thermal oil), natural gas and natural gas liquids.
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.
Fee title interest	Absolute ownership of legal title to mineral lands, subject to conditional interests that may have been granted from the title, such as petroleum and natural gas leases.
FPSO	Floating Production, Storage and Offloading vessel
GHG	Greenhouse gas
gross acres	Total number of acres in which the Company has a working interest or fee title 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

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MMcf/d	million cubic feet per day
MMcfe	millions of cubic feet equivalent
MM\$	million Canadian dollars
NGLs	Natural gas liquids
net acres	Gross acres multiplied by the percentage working interest or fee title 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, natural gas and NGL 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 reference location 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”, “may”, 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, 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, natural gas and NGL 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, natural gas and NGLs 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,

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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.

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 (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl 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 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

The comparative Consolidated Financial Statements and the Company's Management's Discussion and Analysis for the most recently completed fiscal year ended December 31, 2014, herein incorporated by reference, and certain information included in this AIF, have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board.

For the year ended December 31, 2014, the Company retained Independent Qualified Reserves Evaluators ("IQRE"), 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, 2014 and a preparation date of February 2, 2015. 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 NGL 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 2100, 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.

January 1, 2015 - EOG Resources Canada 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:

	Jurisdiction of Incorporation	% Ownership
Subsidiary		
Canadian Natural Upgrading Limited	Alberta	100
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, a general partnership.

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

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

GENERAL DEVELOPMENT OF THE BUSINESS

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. This pipeline is subject to regulatory approval.

During 2012, the Company issued \$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.

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 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. Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the Redwater Partnership’s syndicated credit facility and bonds, over the tolling period of 30 years.

During 2013, the Company discovered bitumen emulsion at surface in areas of the Primrose field. The Company continues to work with the regulator on the causation review of the bitumen emulsion seepage. The Company’s near-term steaming plan at Primrose has been modified, with steaming being reduced in certain areas.

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.

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. 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 \$500 million of 2.89% medium-term notes due August 2020. Net proceeds from the sale were used to repay bank indebtedness and for general corporate purposes.

2014

In 2014, the Company completed the acquisition of certain producing Canadian crude oil and natural gas properties for cash consideration of approximately \$3,110 million, subject to final closing adjustments. 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. The acquired lands and production base are all located in Western Canada in areas adjacent to or near the Company's current conventional operations, primarily in Northeast British Columbia, Northwest Alberta and Northern Plains areas.

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During 2014, the Company continued its ongoing review of its royalty lands and royalty revenue portfolio. As part of the review, a thorough process took place to integrate the newly acquired freehold mineral title and royalty lands with the Company's previously existing royalty portfolio, which also consists of freehold mineral title and royalty lands. The review included a detailed examination of the Company's freehold and royalty land position, production volumes, product mix, associated cash flow and collection of payments. Options for a final strategy as it relates to its fee title and royalty lands include divestiture of the portfolio assets, spin-off of the portfolio assets through an initial public offering or retention of the portfolio assets in their current state.

During 2014, the Company acquired a number of additional crude oil and natural gas properties in the North American Exploration and Production segment for net cash consideration of \$643 million.

In March 2014, the Company issued US\$500 million floating rate unsecured notes due March 30, 2016 at a rate of 3 month LIBOR plus 0.375%, and US\$500 million principal amount of 3.80% unsecured notes due April 15, 2024. Net proceeds were used to repay borrowings under the Company's credit facilities.

In May 2014, the Company issued \$500 million of 2.60% unsecured notes due December 3, 2019 and \$500 million of 3.55% unsecured notes due June 3, 2024. Net proceeds from the sale were used for general corporate purposes relating to the Company's core regions of operations.

In November 2014, the Company issued US\$600 million of 1.75% unsecured notes due January 15, 2018 and US\$600 million of 3.90% unsecured notes due February 1, 2025. Net proceeds from the sale of the notes were used to repay borrowings under the Company's credit facilities.

2015

In January 2015, in response to declining commodity prices and after a proactive review of its capital allocation strategy, the Company announced it would reduce its capital spending by approximately \$2,400 million. Subsequently, capital expenditure guidance for 2015 was further reduced by \$150 million as a result of the reduction in scope of the originally planned 2015 Horizon maintenance turnaround.

In the first quarter of 2015, the Company's existing \$1,000 million non-revolving term credit facility was extended, maturing January 2017. In addition, the Company entered into a new \$1,500 million non-revolving three-year term credit facility maturing April 2018.

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, natural gas and NGLs. 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, natural gas and NGL 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, 2014, the Company had the following full time equivalent permanent employees:

North America, Exploration and Production	4,751
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North America, Oil Sands Mining and Upgrading	2,486
North Sea	368
Offshore Africa	52
Total Company	7,657

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.

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The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces namely: natural gas and NGLs, light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, SCO from our oil sands mining operations and bitumen (thermal oil). 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 33% of 2014 production. Virtually all of the Company's natural gas and NGL production is located in the Canadian provinces of Alberta, British Columbia and Saskatchewan and is marketed in Canada and the US. Light and medium crude oil and NGLs, representing 15% of 2014 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 18% of 2014 production, Pelican Lake heavy crude oil accounting for 6% of 2014 production, and our bitumen (thermal oil) accounting for 14% of 2014 production are in the provinces of Alberta and Saskatchewan. SCO from our oil sands mining operations in Northern Alberta accounted for approximately 14% of 2014 production. Midstream assets, primarily comprised of 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 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 2014, Canadian Natural continued its environmental liability reduction program with the abandonment of 545 inactive wells. In addition, reclamation was initiated at many of these sites with the eventual goal of reclamation certification. In 2014 the Company received 330 reclamation certificates representing 760 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

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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 and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new policies encourage 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 2014 the Company completed approximately 801 gas conservation projects in its primary heavy crude oil operations, resulting in a reduction of 4.4 million tonnes/year of CO<sub>2</sub>e. Over the past five years the Company has spent over \$100 million in its primary heavy crude oil and in situ oil sands operations to conserve the equivalent of over 16.5 million tonnes of CO<sub>2</sub>e. 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 CO<sub>2</sub> capture and the sequestration of CO<sub>2</sub> 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, natural gas and NGL production from leases owned by the province. The royalties are determined by regulation and are generally calculated as a percentage of

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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.

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.

In South Africa, for oil and gas companies, royalty rates range from 0.5% to 5% and the corporate income tax rate is 28%.

### 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, natural gas and NGLs, 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.

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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, the construction by third parties of new or expansion of existing pipeline capacity and other factors, the availability of alternate fuel sources and weather conditions. Natural gas prices realized by the Company are affected primarily in North America by supply and demand, weather conditions, industrial demand, and prices of alternate sources of energy. Any substantial or extended decline in the prices of crude oil or natural gas could result in a delay or cancellation of existing or future drilling, development or construction programs, including but not limited to Horizon, Primrose, Pelican Lake, the Kirby Thermal Oil Sands Project, the North West Redwater bitumen upgrader and refinery 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 38% of the Company's 2014 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, natural gas and NGLs 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

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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, CO<sub>2</sub> capture and sequestration in oil sands tailings, CO<sub>2</sub> capture and storage in association with EOR and participation in COSIA.

In Canada, the federal government has indicated its intent to develop regulations 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, and has released draft regulations pertaining to certain types of equipment operated by the Company.

In Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO<sub>2</sub>e annually. Four of the Company's facilities, the Horizon facility, the Primrose/Wolf Lake in situ heavy crude oil facilities, the Hays sour natural gas plant and the Wapiti 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 CO<sub>2</sub>e on fuel consumed and gas flared in the province. Saskatchewan released draft GHG regulations that regulate facilities emitting more than 50 kilotonnes of CO<sub>2</sub>e 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 CO<sub>2</sub> allocation. In Phase 2 (2008 – 2012) the Company's CO<sub>2</sub> allocation was decreased below the Company's operations emissions. In Phase 3 (2013 - 2020) the Company's CO<sub>2</sub> allocation was further reduced. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO<sub>2</sub> 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 the new tailings process commences 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

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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.

### Project 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.

### 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, natural gas and NGL 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, natural gas and NGL 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

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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.

### 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, 2014, the Company retained Independent Qualified Reserves Evaluators ("IQRE"), 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, 2014 and a preparation date of February 2, 2015. 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 NGL 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 IQRE to review the qualifications of and procedures used by each IQRE 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, natural gas and NGL reserves provided herein are estimates only and there is no guarantee the estimated reserves will be recovered. Actual crude oil, natural gas and NGL reserves may be greater or less than the estimate provided herein.

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## Summary of Company Gross Reserves

As of December 31, 2014

## 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	114	125	233	371	1,969	3,907	96	3,559
Developed								
Non-Producing	5	22	2	-	-	256	5	77
Undeveloped	26	82	39	846	189	1,706	87	1,553
Total Proved	145	229	274	1,217	2,158	5,869	188	5,189
Probable	58	88	121	1,095	1,435	2,057	70	3,210
Total Proved plus Probable	203	317	395	2,312	3,593	7,926	258	8,399
North Sea								
Proved								
Developed								
Producing	28					60		38
Developed								
Non-Producing	10					5		11
Undeveloped	166					18		169
Total Proved	204					83		218
Probable	104					31		109
Total Proved plus Probable	308					114		327
Offshore Africa								
Proved								
Developed								
Producing	24					32		29
Developed								
Non-Producing	-					-		-
Undeveloped	72					17		75
Total Proved	96					49		104
Probable	53					49		61
Total Proved plus Probable	149					98		165
Total Company								
Proved								
	166	125	233	371	1,969	3,999	96	3,626

Developed Producing								
Developed Non-Producing	15	22	2	-	-	261	5	88
Undeveloped	264	82	39	846	189	1,741	87	1,797
Total Proved	445	229	274	1,217	2,158	6,001	188	5,511
Probable	215	88	121	1,095	1,435	2,137	70	3,380
Total Proved plus Probable	660	317	395	2,312	3,593	8,138	258	8,891

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Summary of Company Net Reserves  
As of December 31, 2014  
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	99	105	176	281	1,609	3,436	71	2,913
Developed								
Non-Producing	4	18	1	-	-	215	4	63
Undeveloped	23	69	29	668	155	1,403	68	1,246
Total Proved	126	192	206	949	1,764	5,054	143	4,222
Probable	48	69	82	838	1,139	1,737	53	2,519
Total Proved plus Probable	174	261	288	1,787	2,903	6,791	196	6,741
North Sea								
Proved								
Developed Producing	28					60		38
Developed								
Non-Producing	10					5		11
Undeveloped	166					18		169
Total Proved	204					83		218
Probable	104					31		109
Total Proved plus Probable	308					114		327
Offshore Africa								
Proved								
Developed Producing	21					23		25
Developed								
Non-Producing	-					-		-
Undeveloped	57					13		59
Total Proved	78					36		84
Probable	41					32		46
Total Proved plus Probable	119					68		130
Total Company								
Proved								
Developed Producing	148	105	176	281	1,609	3,519	71	2,976
Developed								
Non-Producing	14	18	1	-	-	220	4	74
Undeveloped	246	69	29	668	155	1,434	68	1,474

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Total Proved	408	192	206	949	1,764	5,173	143	4,524
Probable	193	69	82	838	1,139	1,800	53	2,674
Total Proved plus Probable	601	261	288	1,787	2,903	6,973	196	7,198

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Canadian Natural Resources Limited

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NOTES

1. “Company gross reserves” are Canadian Natural’s working interest share of reserves before deduction of royalties and without including any royalty interests of the Company.
2. “Company net reserves” are the company 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 IQRE to be reasonable.

5. BOE values as presented may not calculate due to rounding.

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, natural gas and NGL 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, 2014  
Forecast Prices and Costs

MM\$

Discount @ 0%

Discount @ 5%

Discount @