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

FORM 40-F

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

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

For the fiscal year ended December 31, 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:

[X] Annual information form [X] Audited annual financial statements

Number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.
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 [X] No [ ]

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

Yes _____ No _____

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
bbl	barrels
bbl/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_2e	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

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

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", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" 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.

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.

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:

	Jurisdiction of Incorporation	% Ownership
Subsidiary		
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.

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.

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

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"); CO_2 reduction programs including the injection of CO_2 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

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 CO_2e. 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 CO_2e. 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_2 capture and the sequestration of CO_2 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.

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

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, CO_2 capture and sequestration in oil sands tailings, CO_2 capture and storage in association with EOR, participation in an industry initiative to promote an integrated CO_2 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.

In Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e 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 CO_2e on fuel consumed and gas flared in the province. Saskatchewan released draft GHG regulations that regulate facilities emitting more than 50 kilotonnes of CO_2e 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_2 allocation. In Phase 2 (2008 – 2012) the Company's CO_2 allocation was decreased below the Company's operations emissions. In Phase 3 (2013 - 2020) the Company's CO_2 allocation was further reduced. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 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.

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.

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.

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
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

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
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

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 producibilty 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.

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.

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.

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)

	North America		North Sea		Offshore Africa		Total	
MM$	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.

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

Future Net Revenue By Production Group

Reserves Category	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.

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.

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	-					-		-
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**

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	-					-		-
Improved Recovery	-					-		-
Acquisitions	-					-		-
Dispositions	-					-		-
Economic Factors	(1)					-		(1)
Technical 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
Improved Recovery	-	-	-	-	-	-	-	-
Acquisitions	4	-	-	-	-	40	-	10
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	1	(2)	1	18	-	3
Technical 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**

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)
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**

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.

Proved Undeveloped Reserves

Year	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

Probable Undeveloped Reserves

Year	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	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

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.

Future Development Costs (Undiscounted)

	North America		North Sea		Offshore Africa		Total	
Year	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.

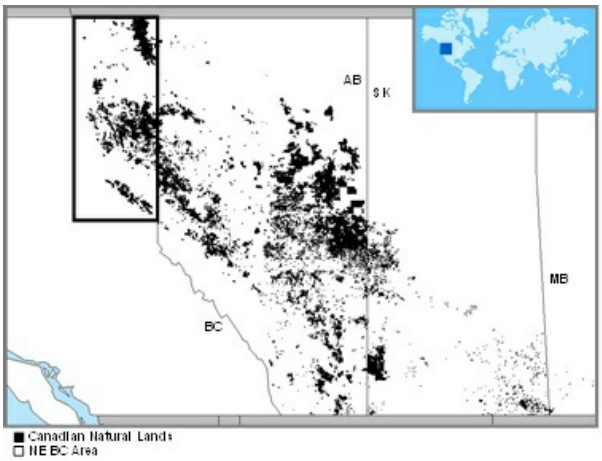
Other Oil and Gas Information

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.

	2013 Average Daily Production Rates		2012 Average Daily Production Rates	
Region	**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

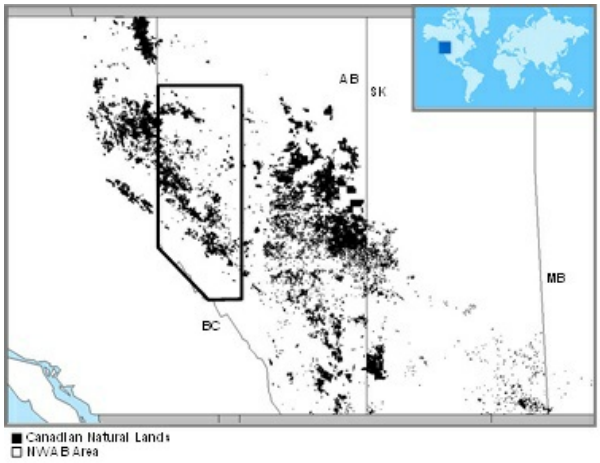


Significant geological variation extends throughout the productive reservoirs in this region located west of the British Columbia and Alberta border to Prince George, British Columbia, producing light and medium crude oil, NGLs and natural gas.

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

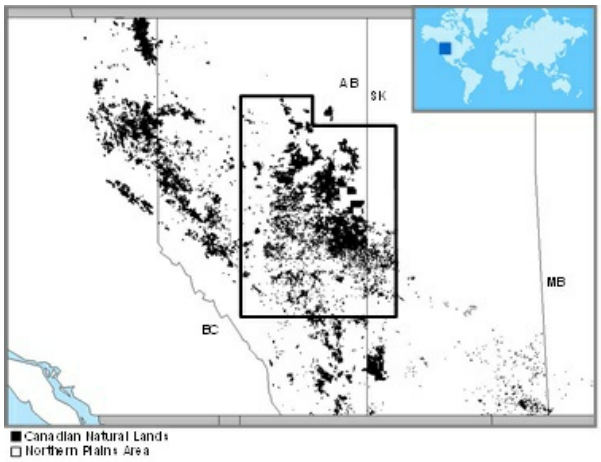
emerging unconventional shale gas plays. The 2006 acquisition of ACC significantly increased the asset base in this area. In 2010, a natural gas processing plant with a design capacity of 50 MMcf/d was completed at our Septimus Montney gas play and in 2011 the Company completed a pipeline to a deep cut 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.

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.

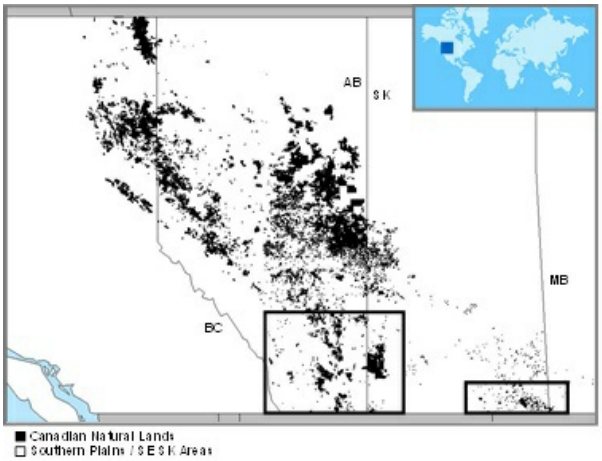
Production of bitumen (thermal oil) from the 100% owned Primrose Field located near Bonnyville, Alberta involves processes that utilize steam to increase the recovery of the bitumen (10°-11°API). The two processes employed by the Company are CSS and SAGD. Both recovery processes inject steam to heat 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

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



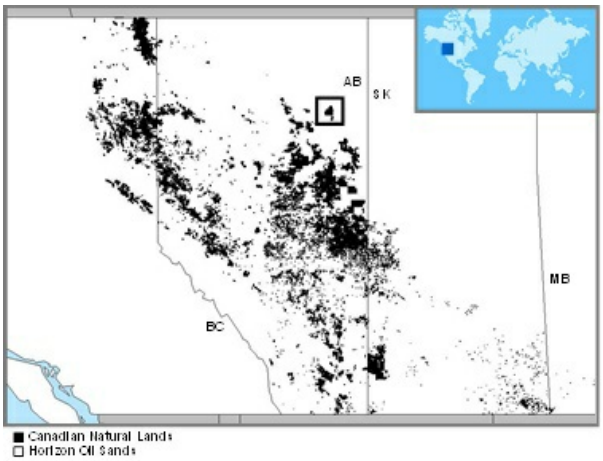
The Southern Plains region is principally located south of the Northern Plains region to the United States border and extending into western Saskatchewan.

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.

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 34ºAPI 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.

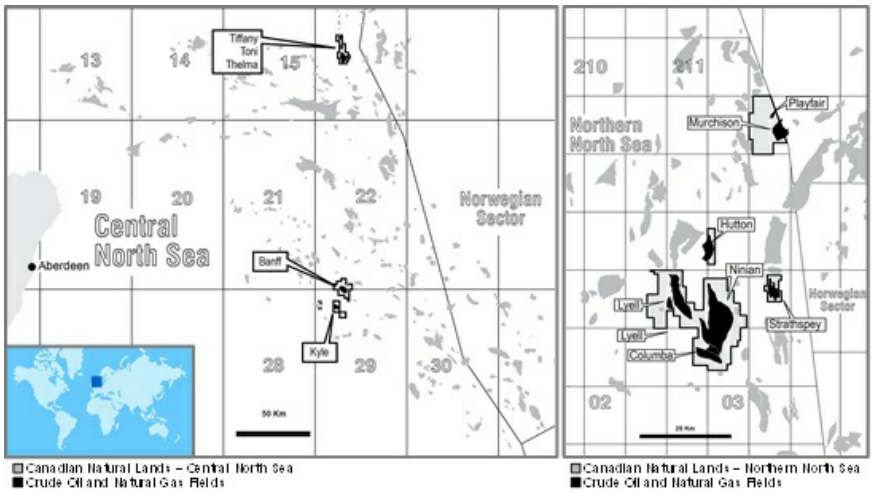
On January 6, 2011, the Company suspended SCO production at its Horizon operations due to a fire in the primary upgrading coking plant. On August 16, the Company successfully and safely resumed production with first pipeline deliveries commencing on August 18, 2011.

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.

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.

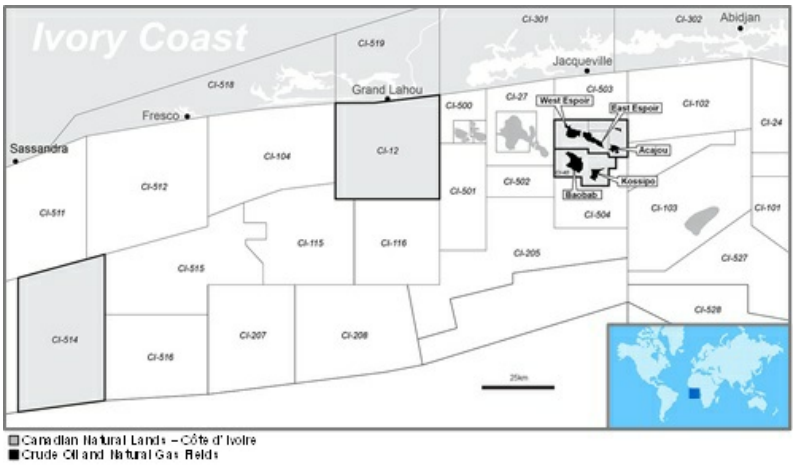
In December 2011, the Banff FPSO and subsea infrastructure suffered storm damage. Operations at Banff/Kyle, with combined net production of approximately 3,500 bbl/d, were suspended. The FPSO is currently undergoing repairs and is targeted to be back in the field early in the third quarter of 2014. The 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.

Offshore Africa

Côte d'Ivoire



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

The Company has a 58.7% operated interested in the Espoir Field in Block CI-26 which is located in water depths ranging from 100 to 700 meters. Production from East Espoir commenced in 2002 and development drilling of West Espoir was completed in 2008. Crude oil from the East and West Espoir Fields is produced to an FPSO with the associated natural gas delivered onshore through a subsea pipeline for local power generation.

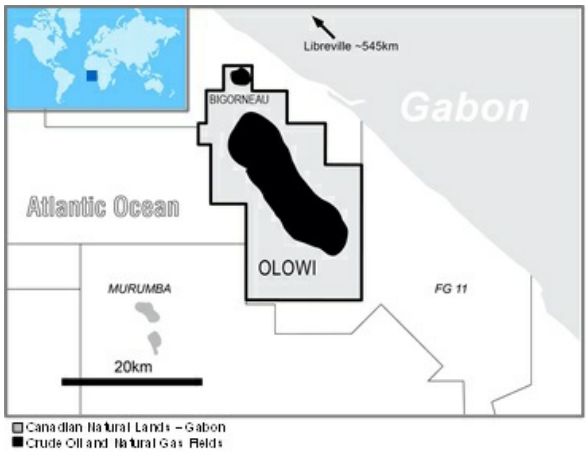
During the fourth quarter of 2011, the Company sanctioned an 8 well drilling program at the Espoir field. Due to operational and safety issues with the drilling contractor, the drilling rig was de-mobilized. The Company is seeking a drilling rig and is assessing the opportunity to commence drilling in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

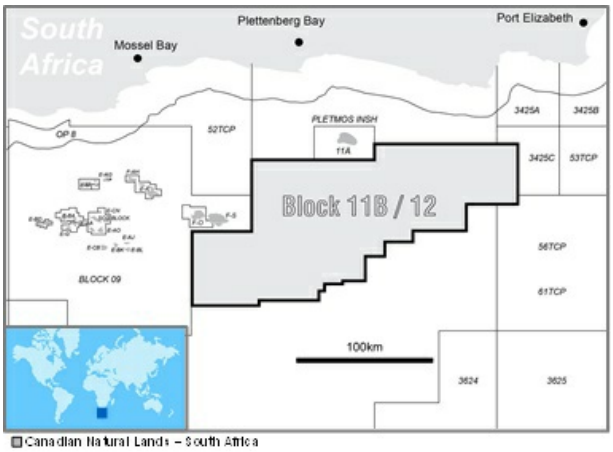
In 2013, the Company acquired a 60% operated working interest in Block CI-12 which is prospective for deepwater channel/fan structures. The block is located approximately 35km west of the Company's current production at Espoir and Baobab. A 3D seismic program has been completed and the data is currently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

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.

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.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Producing	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.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Non Producing	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

Properties With Attributed and No Attributed Reserves

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

	Proved Properties		Unproved Properties		Total Acreage		Average Working Interest
Region (thousands of acres)	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.

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.

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					
		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
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	Gross	-	-	-	-	-	-
and Upgrading	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

		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	Gross	-	-	-	9.0	225.0	234.0
and Upgrading	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

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

Production History

	2013				
	Q1	Q2	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**

Production History

	2013				
	Q1	Q2	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.

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.

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

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.

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.

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, Trilogy Energy Corp., and Manitok 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 Intellipharmaceutics 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.

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.

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.
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.

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 Canada	Vice-President, Exploitation, Central (age 52)	Officer of the Company.

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 Canada	Vice-President, Exploration, East (age 49)	Officer of the Company.
Grant M. Williams Calgary, Alberta Canada	Vice-President, Thermal Exploration (age 56)	Officer of the Company.

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.

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.

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

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)**	**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 Africa	$0	$12,162	$0	$12,162
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.

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

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 “CAMERON P. SIX”
Cameron P. Six, P.Eng.
Vice-President, Unconventional and Director

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 “SCOTT W. PENNELL”
Scott W. Pennell, P.Eng.
Manager, Engineering 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

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.

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

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.

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

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

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

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

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

III Audit Committee Duties and Responsibilities

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

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

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

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

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

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

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

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

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

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

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

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

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

(i) contents of their report, including:

(a) all critical accounting policies and practices used;

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

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

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

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

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

(v) internal resources used;

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

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

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

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

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

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

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

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

b. to review the internal audit plan; and

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

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

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

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

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

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

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

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

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

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

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

   f. to establish procedures for:

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

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

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

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

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

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

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

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"	(signed) "Corey B. Bieber"	(signed) "Murray G. Harris"
Steve W. Laut President	**Corey B. Bieber,** CA Chief Financial Officer & Senior Vice-President, Finance	**Murray G. Harris,** CA Vice-President, Financial Controller & Horizon Accounting

Calgary, Alberta, Canada
March 5, 2014

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

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.

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

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
Prepaids 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

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 – $17 million)	**(1)**	(7)	52
	(5)	24	29
Foreign currency translation adjustment			
Translation of net investment	**(11)**	8	(12)
Other comprehensive (loss) income, net of taxes	**(16)**	32	17
Comprehensive income	**$ 2,254**	$ 1,924	$ 2,660

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

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	–
Deferred income tax expense (recovery)		**31**	(30)	407
Horizon asset impairment provision		**–**	–	396
Gain on corporate acquisition/disposition of properties		**(289)**	–	–
Current income tax on disposition of properties		**58**	–	–
Insurance recovery – property damage		–	–	(393)
Other		**(19)**	(47)	(55)
Abandonment expenditures		**(207)**	(204)	(213)
Net change in non-cash working capital	20	**(33)**	447	(36)
		7,218	6,209	6,243
Financing activities				
Issue (repayment) of bank credit facilities and commercial paper, net		**803**	172	(647)
Issue of medium-term notes, net		**98**	498	–
(Repayment) issue of US dollar debt securities, net	9	**(398)**	(344)	621
Issue of common shares on exercise of stock options		**130**	194	255
Purchase of common shares under Normal Course Issuer Bid		**(320)**	(318)	(104)
Dividends on common shares		**(523)**	(444)	(378)
Net change in non-cash working capital	20	**(23)**	(37)	(15)
		(233)	(279)	(268)
Investing activities				
Net proceeds (expenditures) on exploration and evaluation assets	20	**144**	(309)	(312)
Net expenditures on property, plant and equipment	20	**(7,211)**	(5,795)	(5,889)
Current income tax on disposition of properties		**(58)**	–	–
Investment in other long-term assets		**–**	2	(321)
Net change in non-cash working capital	20	**119**	175	559
		(7,006)	(5,927)	(5,963)
(Decrease) increase in cash and cash equivalents		**(21)**	3	12
Cash and cash equivalents – beginning of year		**37**	34	22
Cash and cash equivalents – end of year		**$ 16**	$ 37	$ 34
Interest paid		**$ 460**	$ 464	$ 456
Income taxes paid		**$ 357**	$ 639	$ 706

Notes to the Consolidated Financial Statements
(tabular amounts in millions of Canadian dollars, unless otherwise stated)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the “Company”) is a senior independent crude oil and natural gas exploration, development and production company. The Company’s exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom (“UK”) portion of the North Sea; and Côte d’Ivoire, Gabon, and South Africa in Offshore Africa.

The Horizon Oil Sands Mining and Upgrading segment (“Horizon”) produces synthetic crude oil through bitumen mining and upgrading operations.

Within Western Canada, the Company maintains certain midstream activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("Redwater Partnership"), a general partnership formed in the Province of Alberta.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2500, 855-2 Street S.W., Calgary, Alberta, Canada.

The Company’s consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”). The accounting policies adopted by the Company under IFRS are set out below. The Company has consistently applied the same accounting policies throughout all periods presented, except where IFRS permits new accounting standards to be adopted prospectively (see note 2).

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements have been prepared under the historical cost basis, unless otherwise required.

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and wholly owned partnerships. Subsidiaries are all entities over which the Company has control. Subsidiaries are fully consolidated from the date on which control is transferred to the Company. They are deconsolidated from the date that control ceases.

Certain of the Company’s activities are conducted through joint arrangements in which two or more parties have joint control. Where the Company has a direct ownership interest in jointly controlled assets and obligations for the liabilities (a “joint operation”), the assets, liabilities, revenue and expenses related to the joint operation are included in the consolidated financial statements in proportion to the Company’s interest. Where the Company has an interest in jointly controlled entities (a “joint venture”), it uses the equity method of accounting. Under the equity method, the Company’s initial and subsequent investments are recognized at cost and subsequently adjusted for the Company’s share of the joint venture’s income or loss, less dividends received.

Joint ventures accounted for using the equity method of accounting are tested for impairment whenever objective evidence indicates that the carrying amount of the investment may not be recoverable. Indications of impairment include a history of losses, significant capital expenditures overruns, liquidity concerns, financial restructuring of the investee and significant adverse changes in the technological, economic or legal environment. The amount of the impairment is measured as the difference between the carrying amount of the investment and the higher of its fair value less costs of disposal and its value in use. Impairment losses are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

(B) SEGMENTED INFORMATION

Operating segments have been determined based on the nature of the Company’s activities and the geographic locations in which the Company operates, and are consistent with the level of information regularly provided to and reviewed by the Company’s chief operating decision makers.

(C) CASH AND CASH EQUIVALENTS

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with an original term to maturity at purchase of three months or less are reported as cash equivalents in the consolidated balance sheets.

(D) INVENTORY

Inventory is primarily comprised of product inventory and materials and supplies. Product inventory includes crude oil held for sale, pipeline linefill and crude oil stored in floating production, storage and offloading vessels. Inventories are carried at the lower of cost and net realizable value. Cost consists of purchase costs, direct production costs, directly attributable overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Net realizable value for product inventory is determined by reference to forward prices, and for materials and supplies is based on current market prices as at the date of the consolidated balance sheets.

(E) EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation ("E&E") assets consist of the Company's crude oil and natural gas exploration projects that are pending the determination of proved reserves.

E&E costs are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area. These costs are recognized in net earnings.

Once the technical feasibility and commercial viability of E&E assets are determined and a development decision is made by management, the E&E assets are tested for impairment upon reclassification to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made.

E&E assets are also tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of Cash Generating Units ("CGUs"), aggregated at the segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks.

(F) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Assets under construction are not depleted or depreciated until available for their intended use. The capitalized value of a finance lease is included in property, plant and equipment.

Exploration and Production

When significant components of an item of property, plant and equipment, including crude oil and natural gas interests, have different useful lives, they are accounted for separately.

The cost of an asset comprises its acquisition, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs. Property acquisition costs are comprised of the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves.

Oil Sands Mining and Upgrading

Capitalized costs for the Oil Sands Mining and Upgrading segment are reported separately from the Company's North America Exploration and Production segment. Capitalized costs include property acquisition, construction and development costs, the estimate of any asset retirement costs, and applicable borrowing costs.

Mine-related costs are amortized on the unit-of-production method based on Horizon proved reserves. Costs of the upgrader and related infrastructure located on the Horizon site are amortized on the unit-of-production method based on productive capacity of the upgrader and related infrastructure. Other equipment is depreciated on a straight-line basis over its estimated useful life ranging from 2 to 15 years.

Midstream and Head Office

The Company capitalizes all costs that expand the capacity or extend the useful life of the assets. Midstream assets are depreciated on a straight-line basis over their estimated useful lives ranging from 5 to 30 years. Head office assets are amortized on a declining balance basis.

Useful lives

The depletion rates and expected useful lives of property, plant and equipment are reviewed on an annual basis, with changes in depletion rates and useful lives accounted for prospectively.

Derecognition

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is recognized in net earnings.

Major maintenance expenditures

Inspection costs associated with major maintenance turnarounds are capitalized and amortized over the period to the next major maintenance turnaround. All other maintenance costs are expensed as incurred.

Impairment

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If any such indication of impairment exists, the Company performs an impairment test related to the assets. Individual assets are grouped for impairment assessment purposes into CGU's, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount.

In subsequent periods, an assessment is made at each reporting date to determine whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is re-estimated and the net carrying amount of the asset is increased to its revised recoverable amount. The revised recoverable amount cannot exceed the carrying amount that would have been determined, net of depletion, had no impairment loss been recognized for the asset in prior periods. Such reversal is recognized in net earnings. After a reversal, the depletion charge is adjusted in future periods to allocate the asset's revised carrying amount over its remaining useful life.

(G) BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed in a business combination are recognized at their fair value at the date of the acquisition. Any excess of the consideration paid over the fair value of the net assets acquired is recognized as an asset. Any excess of the fair value of the net assets acquired over the consideration paid is credited to net earnings.

(H) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during the initial development of a mine are capitalized to property, plant and equipment. Overburden removal costs incurred during the production of a mine are included in the cost of inventory, unless the overburden removal activity has resulted in a probable inflow of future economic benefits to the Company, in which case the costs are capitalized to property, plant and equipment. Capitalized overburden removal costs are amortized over the life of the mining reserves that directly benefit from the overburden removal activity.

(I) CAPITALIZED BORROWING COSTS

Borrowing costs attributable to the acquisition, construction or production of qualifying assets are capitalized to the cost of those assets until such time as the assets are substantially available for their intended use. Qualifying assets are comprised of those significant assets that require a period greater than one year to be available for their intended use. All other borrowing costs are recognized in net earnings.

(J) LEASES

Finance leases, which transfer substantially all of the risks and rewards incidental to ownership of the leased item to the Company, are capitalized at the commencement of the lease term at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term. Operating lease payments are recognized in net earnings over the lease term.

(K) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on all of its property, plant and equipment based on current legislation and industry operating practices. Provisions for asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Provisions are measured at the present value of management's best estimate of expenditures required to settle the obligation as at the date of the balance sheet. Subsequent to the initial measurement, the obligation is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes due to discount rates or estimated future cash flows are capitalized to or derecognized from property, plant, and equipment. Actual costs incurred upon settlement of the asset retirement obligation are charged against the provision.

(L) FOREIGN CURRENCY TRANSLATION

Functional and presentation currency

Items included in the financial statements of the Company's subsidiary companies and partnerships are measured using the currency of the primary economic environment in which the subsidiary operates (the "functional currency"). The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

The assets and liabilities of subsidiaries that have a functional currency different from that of the Company are translated into Canadian dollars at the closing rate at the date of the balance sheet, and revenue and expenses are translated at the average rate for the period. Cumulative foreign currency translation adjustments are recognized in other comprehensive income.

When the Company disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in other comprehensive income related to the foreign operation are recognized in net earnings.

Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at balance sheet date exchange rates of monetary assets and liabilities denominated in currencies other than the functional currency of the Company or its subsidiaries are recognized in net earnings.

(M) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the sale of crude oil and natural gas is recognized when title passes to the customer, delivery has taken place and collection is reasonably assured. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Revenue represents the Company's share net of royalty payments to governments and other mineral interest owners. Related costs of goods sold are comprised of production, transportation and blending, and depletion, depreciation and amortization expenses. These amounts have been separately presented in the consolidated statements of earnings.

(N) PRODUCTION SHARING CONTRACTS

Production generated from Offshore Africa is shared under the terms of various Production Sharing Contracts ("PSCs"). Product sales are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the respective Government State Oil Companies (the "Governments"). Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Governments. The Governments' share of profit oil attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the terms of the respective PSCs.

(O) INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases.

Deferred income tax assets and liabilities are calculated using the substantively enacted income tax rates that are expected to apply when the asset or liability is recovered. Deferred income tax assets or liabilities are not recognized when they arise on the initial recognition of an asset or liability in a transaction (other than in a business combination) that, at the time of the transaction, affects neither accounting nor taxable profit. Deferred income tax assets or liabilities are also not recognized on possible future distributions of retained earnings of subsidiaries where the timing of the distribution can be controlled by the Company and it is probable that a distribution will not be made in the foreseeable future, or when distributions can be made without incurring income taxes.

Deferred income tax assets for deductible temporary differences and tax loss carryforwards are recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized. The carrying amount of deferred income tax assets is reviewed at each reporting date, and is reduced if it is no longer probable that sufficient future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized.

Current income tax is calculated based on net earnings for the period, adjusted for items that are non-taxable or taxed in different periods, using income tax rates that are substantively enacted at each reporting date.

Income taxes are recognized in net earnings or other comprehensive income, consistent with the items to which they relate.

(P) SHARE-BASED COMPENSATION

The Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The liability for awards granted to employees is initially measured based on the grant date fair value of the awards and the number of awards expected to vest. The awards are re-measured each reporting period for subsequent changes in the fair value of the liability. Fair value is determined using the Black-Scholes valuation model. Expected volatility is estimated based on historic results. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by the employee and any previously recognized liability associated with the stock options are recorded as share capital. The unamortized costs of employer contributions to the Company's share bonus program are included in other long-term assets.

(Q) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: fair value through profit or loss; held-to-maturity investments; loans and receivables; and financial liabilities measured at amortized cost. All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Fair value through profit or loss financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash, cash equivalents, and accounts receivable are classified as loans and receivables. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as other financial liabilities measured at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

Financial assets and liabilities are also categorized using a three-level hierarchy that reflects the significance of the inputs used in making fair value measurements for these assets and liabilities. The fair values of financial assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of financial assets and liabilities in Level 2 are based on inputs other than Level 1 quoted prices that are observable for the asset or liability either directly (as prices) or indirectly (derived from prices). The fair values of Level 3 financial assets and liabilities are not based on observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability.

Transaction costs in respect of financial instruments at fair value through profit or loss are recognized in net earnings. Transaction costs in respect of other financial instruments are included in the initial measurement of the financial instrument.

Impairment of financial assets

At each reporting date, the Company assesses whether there is objective evidence that a financial asset is impaired. If such evidence exists, an impairment loss is recognized.

Impairment losses on financial assets carried at amortized cost including loans and receivables are calculated as the difference between the amortized cost of the loan or receivable and the present value of the estimated future cash flows, discounted using the instrument's original effective interest rate. Impairment losses on financial assets carried at amortized cost are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

(R) RISK MANAGEMENT ACTIVITIES

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The carrying amount of a risk management liability is adjusted for the Company's own credit risk.

The Company documents all derivative financial instruments that are formally designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company periodically enters into commodity price contracts to manage anticipated sales and purchases of crude oil and natural gas in order to protect its cash flow for its capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts formally designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in net earnings in the same period or periods in which the commodity is sold or purchased. The ineffective portion of changes in the fair value of these designated contracts is recognized in risk management activities in net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in net earnings.

The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on certain of its long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are recognized in interest expense in net earnings. Changes in the fair value of non-designated interest rate swap contracts are recognized in risk management activities in net earnings.

Cross currency swap contracts are periodically used to manage currency exposure on US dollar denominated long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges related to the notional principal amounts are recognized in foreign exchange gains and losses in net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to interest expense when the hedged item is recognized in net earnings, with the ineffective portion recognized in risk management activities in net earnings. Changes in the fair value of non-designated cross currency swap contracts are recognized in risk management activities in net earnings.

Realized gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged items are recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized in net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in net earnings.

Upon termination of an interest rate swap designated as a fair value hedge, the interest rate swap is derecognized on the consolidated balance sheets and the related long-term debt hedged is no longer revalued for subsequent changes in fair value. The fair value adjustment on the long-term debt at the date of termination of the interest rate swap is amortized to interest expense over the remaining term of the long-term debt.

Foreign currency forward contracts are periodically used to manage foreign currency cash requirements. The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of foreign currency forward contracts designated as cash flow hedges are initially recorded in other comprehensive income and are reclassified to foreign exchange gains and losses when the hedged item is recognized in net earnings. Changes in the fair value of non-designated foreign currency forward contracts are recognized in risk management activities in net earnings.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not clearly and closely related to the host contract.

(S) COMPREHENSIVE INCOME

Comprehensive income is comprised of the Company's net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses arising from the net investment in foreign operations that do not have a Canadian dollar functional currency. Other comprehensive income is shown net of related income taxes.

(T) PER COMMON SHARE AMOUNTS

The Company calculates basic earnings per common share by dividing net earnings by the weighted average number of common shares outstanding during the period. As the Company's Option Plan allows for the settlement of stock options in either cash or shares at the option of the holder, diluted earnings per common share is calculated using the more dilutive of cash settlement or share settlement under the treasury stock method.

(U) SHARE CAPITAL

Common shares are classified as equity. Costs directly attributable to the issue of new shares or options are included in equity as a deduction from proceeds, net of tax. When the Company acquires its own common shares, share capital is reduced by the average carrying value of the shares purchased. The excess of the purchase price over the average carrying value is recognized as a reduction of retained earnings. Shares are cancelled upon purchase.

(V) DIVIDENDS

Dividends on common shares are recognized in the Company's financial statements in the period in which the dividends are approved by the Board of Directors.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2013, the Company adopted the following new accounting standards issued by the IASB:

a) IFRS 10 "Consolidated Financial Statements" replaced IAS 27 "Consolidated and Separate Financial Statements" (IAS 27 still contains guidance for Separate Financial Statements) and Standing Interpretations Committee ("SIC") 12 "Consolidation – Special Purpose Entities". IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on applying the control principle to determine whether an investor controls an investee.

   IFRS 11 "Joint Arrangements" replaced IAS 31 "Interests in Joint Ventures" and SIC 13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers". The new standard defines two types of joint arrangements, joint operations and joint ventures. In a joint operation, the parties with joint control have rights to the assets and obligations for the liabilities of the joint arrangement and are required to recognize their proportionate interest in the assets, liabilities, revenues and expenses of the joint arrangement. In a joint venture, the parties have an interest in the net assets of the arrangement and are required to apply the equity method of accounting.

   IFRS 12 "Disclosure of Interests in Other Entities". The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities.

   The Company adopted these standards retrospectively. Adoption of these standards did not have a material impact on the Company's consolidated financial statements.

b) IFRS 13 "Fair Value Measurement" provides guidance on the application of fair value where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value. IFRS 13 was adopted prospectively. As a result of adoption of this standard, the Company has included its own credit risk in measuring the carrying amount of a risk management liability with no material impact on the Company's consolidated financial statements.

c) Amendments to IAS 1 "Presentation of Financial Statements" require items of other comprehensive income that may be reclassified to net earnings to be grouped together. The amendments also require that items in other comprehensive income and net earnings be presented as either a single statement or two consecutive statements. Adoption of this amended standard impacted presentation only.

d) IFRS Interpretation Committee ("IFRIC") 20 "Stripping Costs in the Production Phase of a Surface Mine" requires overburden removal costs during the production phase to be capitalized and depreciated if the Company can demonstrate that probable future economic benefits will be realized, the costs can be reliably measured, and the Company can identify the component of the ore body for which access has been improved. Adoption of this standard did not have a material impact on the Company's consolidated financial statements.

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In November 2013, the IASB issued amendments to IFRS 9 "Financial Instruments" to provide guidance on hedge accounting and associated disclosures as part of its overall Financial Instruments project to replace IAS 39 "Financial Instruments – Recognition and Measurement". The new hedge accounting guidance in IFRS 9 replaces strict quantitative tests of effectiveness with less restrictive assessments of how well the hedging instrument accomplishes the Company's risk management objectives for financial and non-financial risk exposures. The new guidance also allows entities to hedge components of non-financial items.

Previous amendments to IFRS 9 replaced the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income.

As part of the November 2013 amendments to IFRS 9, the IASB removed the January 1, 2015 mandatory effective date, and did not provide a new mandatory effective date. However, entities may still choose to apply IFRS 9 immediately.

Effective January 1, 2014, the Company adopted IFRS 9 with no material impact on the Company's consolidated financial statements.

4. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

The Company has made estimates, assumptions and judgements regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements, primarily related to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts. The estimates, assumptions and judgements that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

(A) Crude Oil and Natural Gas Reserves

Purchase price allocations, depletion, depreciation and amortization, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties, interpretations and judgements. The Company expects that, over time, its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices.

(B) Asset Retirement Obligations

The Company provides for asset retirement obligations on its property, plant and equipment based on current legislation and operating practices. Estimated future costs include assumptions on dates of future abandonment and technological advances and estimates of future inflation rates and discount rates. Actual costs may vary from the estimated provision due to changes in environmental legislation, the impact of inflation, changes in technology, changes in operating practices, and changes in the date of abandonment due to changes in reserve life, and may have a material impact on the estimated provision.

(C) Income Taxes

The Company is subject to income taxes in numerous legal jurisdictions. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes liabilities for potential tax audit issues based on assessments of whether additional taxes will likely be due.

(D) Fair Value of Derivatives and Other Financial Instruments

The fair value of financial instruments that are not traded in an active market is determined using valuation techniques. The Company uses its judgement to select a variety of methods and make assumptions that are primarily based on market conditions existing at the end of each reporting period. The Company uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates.

(E) Purchase Price Allocations

Purchase prices related to business combinations and asset acquisitions are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation, and amortization expense and impairment tests.

(F) Share-Based Compensation

The Company has made various assumptions in estimating the fair values of the stock options granted under the Option Plan, including expected volatility, expected exercise timing and future forfeiture rates. At each period end, stock options outstanding are remeasured for changes in the fair value of the liability.

(G) Identification of CGUs

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGUs requires significant judgement and interpretations with respect to the integration between assets, the existence of active markets, shared infrastructures, and the way in which management monitors the Company's operations.

(H) Impairment of Assets

The recoverable amount of a CGU or an individual asset has been determined as the higher of the CGU's or the asset's fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves, discount rates and income taxes as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGU's.

(I) Contingencies

Contingencies are subject to measurement uncertainty as the related financial impact will only be confirmed by the outcome of a future event. The assessment of contingencies requires the application of judgements and estimates including the determination of whether a present obligation exists and the reliable estimation of the timing and amount of cash flows required to settle the contingency.

5. INVENTORY

		2013		2012
Product inventory	**$**	**342**	$	315
Materials and supplies		**290**		239
	$	**632**	$	554

6. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2011	$ 2,442	$ –	$ 33	$ –	$ 2,475
Additions	295	–	14	–	309
Transfers to property, plant and equipment	(173)	–	–	–	(173)
At December 31, 2012	2,564	–	47	–	2,611
Additions	**90**	**–**	**29**	**–**	**119**
Transfers to property, plant and equipment	**(84)**	**–**	**–**	**–**	**(84)**
Disposals	**–**	**–**	**(39)**	**–**	**(39)**
Foreign exchange adjustments	**–**	**–**	**2**	**–**	**2**
At December 31, 2013	**$ 2,570**	**$ –**	**$ 39**	**$ –**	**$ 2,609**

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, resulting in a pre-tax gain on sale of exploration and evaluation property of $224 million ($166 million after-tax). 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.

7. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2011	$ 46,120	$ 4,147	$ 3,044	$ 15,211	$ 298	$ 234	$ 69,054
Additions	4,160	556	75	1,757	14	36	6,598
Transfers from E&E assets	173	–	–	–	–	–	173
Disposals/derecognitions	(129)	(39)	(8)	(5)	–	–	(181)
Foreign exchange adjustments and other	–	(90)	(66)	–	–	–	(156)
At December 31, 2012	50,324	4,574	3,045	16,963	312	270	75,488
Additions	**3,630**	**299**	**97**	**2,772**	**196**	**38**	**7,032**
Transfers from E&E assets	**84**	**–**	**–**	**–**	**–**	**–**	**84**
Disposals/derecognitions	**(228)**	**–**	**–**	**(369)**	**–**	**–**	**(597)**
Foreign exchange adjustments and other	**–**	**327**	**214**	**–**	**–**	**–**	**541**
At December 31, 2013	**$ 53,810**	**$ 5,200**	**$ 3,356**	**$ 19,366**	**$ 508**	**$ 308**	**$ 82,548**
Accumulated depletion and depreciation							
At December 31, 2011	$ 21,721	$ 2,512	$ 2,152	$ 776	$ 96	$ 166	$ 27,423
Expense	3,399	294	165	447	7	16	4,328
Disposals/derecognitions	(129)	(39)	(6)	(5)	–	–	(179)
Foreign exchange adjustments and other	–	(58)	(38)	(16)	–	–	(112)
At December 31, 2012	24,991	2,709	2,273	1,202	103	182	31,460
Expense	**3,551**	**548**	**134**	**582**	**8**	**21**	**4,844**
Disposals/derecognitions	**(228)**	**–**	**–**	**(369)**	**–**	**–**	**(597)**
Foreign exchange adjustments and other	**1**	**210**	**144**	**(1)**	**–**	**–**	**354**
At December 31, 2013	**$ 28,315**	**$ 3,467**	**$ 2,551**	**$ 1,414**	**$ 111**	**$ 203**	**$ 36,061**
Net book value							
- at December 31, 2013	**$ 25,495**	**$ 1,733**	**$ 805**	**$ 17,952**	**$ 397**	**$ 105**	**$ 46,487**
- at December 31, 2012	$ 25,333	$ 1,865	$ 772	$ 15,761	$ 209	$ 88	$ 44,028

Project costs not subject to depletion and depreciation	**2013**	2012
Horizon	**$ 4,051**	$ 2,066
Kirby Thermal Oil Sands	**$ 1,532**	$ 1,021

During 2013, the Company acquired a number of producing crude oil and natural gas properties in the North American and North Sea Exploration and Production segments, including properties from the acquisition of Barrick Energy Inc. effective July 31, 2013, for total cash consideration of $252 million (2012 – $144 million; 2011 – $1,012 million). These transactions were accounted for using the acquisition method of accounting. In connection with these acquisitions, the Company assumed associated asset retirement obligations of $131 million (2012 – $12 million; 2011 – $79 million) and recognized net deferred tax assets of $75 million (2012 – $nil; 2011 – $nil) related to temporary differences in the carrying amount of the acquired properties and their tax bases. Interests in jointly controlled assets were acquired with full tax basis. No debt obligations were assumed. The Company recognized after-tax gains of $65 million (2012 – $nil; 2011 – $nil) on these acquisitions.

Subsequent to December 31, 2013, 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.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. During 2013, pre-tax interest of $175 million (2012 – $98 million; 2011 – $59 million) was capitalized to property, plant and equipment using a capitalization rate of 4.4% (2012 – 4.8%; 2011 – 4.7%).

8. OTHER LONG-TERM ASSETS

		2013		2012
Investment in North West Redwater Partnership	**$**	**306**	$	310
Other		**136**		117
	$	**442**	$	427

Other long-term assets include an investment in the 50% owned Redwater Partnership. Based on Redwater Partnership's voting and decision-making structure and legal form, the investment is accounted for as a joint venture using the equity method. Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement. During 2012, the Project received board sanction from Redwater Partnership and its partners.

The assets, liabilities, partners' equity and equity loss related to Redwater Partnership and the Company's 50% interest at December 31, 2013 were comprised as follows:

		Redwater Partnership 100% interest		**Company 50% interest**
Current assets	**$**	**42**	**$**	**21**
Non-current assets	**$**	**1,404**	**$**	**702**
Current liabilities	**$**	**132**	**$**	**66**
Non-current liabilities	**$**	**702**	**$**	**351**
Partners' equity	**$**	**612**	**$**	**306**
Equity loss	**$**	**8**	**$**	**4**

Non-current liabilities at December 31, 2013 included interim borrowings of $702 million by Redwater Partnership under credit facilities totaling $1,200 million, with original maturities no later than December 2017. These facilities are secured by a floating charge on the assets of Redwater Partnership with a mandatory repayment required from future financing proceeds. At maturity, under its processing agreement, the Company would be obligated to pay its 25% pro rata share of any shortfall.

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.

Redwater Partnership has entered into various agreements related to the engineering, procurement and construction of the Project. These contracts can be cancelled by Redwater Partnership upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

Subsequent to December 31, 2013, the credit facility maturity date was amended to mature on November 28, 2014. At maturity or at such later date as mutually agreed to by the lenders and Redwater Partnership, the Company will be obligated to repay its 25% pro rata share of any amount outstanding under the facility. As at March 4, 2014, interim borrowings under the facilities were $857 million.

9. LONG-TERM DEBT

		2013		2012
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**1,246**	$	971
Medium-term notes				
4.50% debentures due January 23, 2013		**–**		400
4.95% debentures due June 1, 2015		**400**		400
3.05% debentures due June 19, 2019		**500**		500
2.89% debentures due August 14, 2020		**500**		–
		2,646		2,271
US dollar denominated debt, unsecured				
Commercial paper (2013 – US$500 million; 2012 – US$nil)		**532**		–
US dollar debt securities				
5.15% due February 1, 2013 (2013 – US$nil; 2012 – US$400 million)		**–**		398
1.45% due November 14, 2014 (US$500 million)		**532**		498
4.90% due December 1, 2014 (US$350 million)		**372**		348
6.00% due August 15, 2016 (US$250 million)		**266**		249
5.70% due May 15, 2017 (US$1,100 million)		**1,169**		1,094
5.90% due February 1, 2018 (US$400 million)		**426**		398
3.45% due November 15, 2021 (US$500 million)		**532**		498
7.20% due January 15, 2032 (US$400 million)		**426**		398
6.45% due June 30, 2033 (US$350 million)		**372**		348
5.85% due February 1, 2035 (US$350 million)		**372**		348
6.50% due February 15, 2037 (US$450 million)		**479**		448
6.25% due March 15, 2038 (US$1,100 million)		**1,169**		1,094
6.75% due February 1, 2039 (US$400 million)		**426**		398
Less: original issue discount on US dollar debt securities (1)		**(18)**		(20)
		7,055		6,497
Fair value impact of interest rate swaps on US dollar debt securities (2)		**9**		19
		7,064		6,516
Long-term debt before transaction costs		**9,710**		8,787
Less: transaction costs (1) (3)		**(49)**		(51)
		9,661		8,736
Less: current portion of commercial paper		**532**		–
current portion of long-term debt (1) (2) (3)		**912**		798
	$	**8,217**	$	7,938

(1) The Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying amount of the outstanding debt.

(2) The carrying amount of US$350 million of 4.90% notes due December 2014 was adjusted by $9 million (December 31, 2012– $19 million) to reflect the fair value impact of hedge accounting.

(3) *Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.*

Bank Credit Facilities and Commercial Paper

As at December 31, 2013, the Company had in place bank credit facilities of $4,801 million, comprised of:

— a $200 million demand credit facility;

— a $75 million demand credit facility;

— a revolving syndicated credit facility of $1,500 million maturing June 2016;

— a revolving syndicated credit facility of $3,000 million maturing June 2017; and

— a £15 million demand credit facility related to the Company's North Sea operations.

During 2013, the $3,000 million revolving syndicated credit facility was extended to June 2017. Each of the $3,000 million and $1,500 million facilities is extendible annually for one-year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

During 2013, the Company established a US commercial paper program. Borrowings of up to a maximum US$1,500 million are authorized. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at December 31, 2013, was 1.9% (December 31, 2012 – 2.2%), and on long-term debt outstanding for the year ended December 31, 2013 was 4.4% (December 31, 2012 – 4.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $395 million, including a $65 million financial guarantee related to Horizon and $226 million of letters of credit related to North Sea operations, were outstanding at December 31, 2013.

Medium-Term Notes

During 2013, the Company repaid $400 million of 4.50% medium-term notes and issued $500 million of 2.89% medium-term notes due August 2020. Proceeds from the securities issued were used to repay bank indebtedness and for general corporate purposes.

During 2013, the Company filed a base shelf prospectus that allows for the issue of up to $3,000 million of medium-term notes in Canada, which expires in December 2015. If issued, these securities will bear interest as determined at the date of issuance.

During 2012, the Company issued $500 million of 3.05% medium-term notes due June 2019.

US Dollar Debt Securities

During 2013, the Company repaid US$400 million of 5.15% notes and filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States, which expires in December 2015. If issued, these securities will bear interest as determined at the date of issuance.

During 2012, the Company repaid US$350 million of 5.45% notes.

Scheduled Debt Repayments

Scheduled debt repayments are as follows:

Year		Repayment
2014	$	1,436
2015	$	400
2016	$	931
2017	$	1,750
2018	$	426
Thereafter	$	4,776

10. OTHER LONG-TERM LIABILITIES

		2013		2012
Asset retirement obligations	**$**	**4,162**	$	4,266
Share-based compensation		**260**		154
Risk management (note 18)		**136**		257
Other		**65**		87
		4,623		4,764
Less: current portion		**275**		155
	$	**4,348**	$	4,609

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 5.0% (2012 – 4.3%; 2011 – 4.6%). Reconciliations of the discounted asset retirement obligations were as follows:

		2013		2012		2011
Balance – beginning of year	**$**	**4,266**	$	3,577	$	2,624
Liabilities incurred		**62**		51		42
Liabilities acquired		**131**		12		79
Liabilities settled		**(207)**		(204)		(213)
Asset retirement obligation accretion		**171**		151		130
Revision of estimates		**375**		384		472
Change in discount rate		**(723)**		315		422
Foreign exchange adjustments		**87**		(20)		21
Balance – end of year	**$**	**4,162**	$	4,266	$	3,577

Segmented Asset Retirement Obligations

		2013		2012
Exploration and Production				
North America	**$**	**1,707**	$	2,079
North Sea		**1,090**		1,030
Offshore Africa		**225**		218
Oil Sands Mining and Upgrading		**1,138**		937
Midstream		**2**		2
	$	**4,162**	$	4,266

Share-Based Compensation

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered, a liability for potential cash settlements is recognized. The current portion represents the maximum amount of the liability payable within the next twelve month period if all vested stock options are surrendered for cash settlement.

	2013	2012	2011
Balance – beginning of year	**$ 154**	$ 432	$ 663
Share-based compensation expense (recovery)	**135**	(214)	(102)
Cash payment for stock options surrendered	**(4)**	(7)	(14)
Transferred to common shares	**(50)**	(45)	(115)
Capitalized to (recovered from) Oil Sands Mining and Upgrading	**25**	(12)	–
Balance – end of year	**260**	154	432
Less: current portion	**216**	129	384
	$ 44	$ 25	$ 48

The share-based compensation liability of $260 million at December 31, 2013 (2012 – $154 million; 2011 – $432 million) was estimated using the Black-Scholes valuation model with the following weighted average assumptions:

	2013	2012	2011
Fair value	**$ 7.08**	$ 4.60	$ 10.84
Share price	**$ 35.94**	$ 28.64	$ 38.15
Expected volatility	**27.2%**	32.6%	36.9%
Expected dividend yield	**2.2%**	1.5%	0.9%
Risk free interest rate	**1.5%**	1.3%	1.1%
Expected forfeiture rate	**4.6%**	4.2%	4.7%
Expected stock option life (1)	**4.5 years**	4.5 years	4.5 years

(1) At original time of grant.

The intrinsic value of vested stock options at December 31, 2013 was $72 million (2012 – $36 million; 2011 – $173 million).

11. HORIZON ASSET IMPAIRMENT PROVISION AND INSURANCE RECOVERY

In 2011, the Company recognized an asset impairment provision in the Oil Sands Mining and Upgrading segment of $396 million, net of accumulated depletion and amortization, related to the property damage resulting from a fire in the Horizon primary upgrading coking plant. The Company also recorded final property damage insurance recoveries of $393 million and business interruption insurance recoveries of $333 million in 2011. In 2012, upon final settlement of its insurance claims, all outstanding insurance proceeds were collected.

12. INCOME TAXES

The provision for income tax was as follows:

		2013		2012		2011
Current corporate income tax – North America	**$**	**544**	$	366	$	315
Current corporate income tax – North Sea		**23**		115		245
Current corporate income tax – Offshore Africa		**202**		206		140
Current PRT[(1)] (recovery) expense – North Sea		**(56)**		44		135
Other taxes		**22**		16		25
Current income tax expense		**735**		747		860
Deferred corporate income tax expense		**163**		–		412
Deferred PRT[(1)] recovery – North Sea		**(132)**		(30)		(5)
Deferred income tax expense (recovery)		**31**		(30)		407
Income tax expense	**$**	**766**	$	717	$	1,267

(1) Petroleum Revenue Tax.

The provision for income tax is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes. The reasons for the difference are as follows:

		2013		2012		2011
Canadian statutory income tax rate		**25.1%**		25.1%		26.6%
Income tax provision at statutory rate	**$**	**762**	$	655	$	1,040
Effect on income taxes of:						
UK PRT and other taxes		**(166)**		30		155
Impact of deductible UK PRT and other taxes on corporate income tax		**111**		(13)		(77)
Foreign and domestic tax rate differentials		**(66)**		63		74
Non-taxable portion of foreign exchange loss (gain)		**14**		(2)		6
Stock options exercised for common shares		**33**		(56)		(31)
Income tax rate and other legislative changes		**15**		58		104
Non-taxable gain on corporate acquisition		**(16)**		–		–
Revisions arising from prior year tax filings		**57**		(10)		5
Other		**22**		(8)		(9)
Income tax expense	**$**	**766**	$	717	$	1,267

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

		2013		2012
Deferred income tax liabilities				
Property, plant and equipment and exploration and evaluation assets	**$**	**9,180**	$	8,834
Timing of partnership items		**632**		831
Unrealized foreign exchange gain on long-term debt		**87**		142
Deferred PRT		**–**		42
PRT deduction for corporate income tax		**56**		–
		9,955		9,849
Deferred income tax assets				
Asset retirement obligations		**(1,326)**		(1,362)
Loss carryforwards		**(199)**		(119)
Unrealized risk management activities		**(23)**		(36)
Deferred PRT		**(90)**		–
PRT deduction for corporate income tax		**–**		(26)
Other		**(134)**		(132)
		(1,772)		(1,675)
Net deferred income tax liability	**$**	**8,183**	$	8,174

Movements in deferred tax assets and liabilities recognized in net earnings during the year were as follows:

		2013		2012		2011
Property, plant and equipment and exploration and evaluation assets	**$**	**250**	$	465	$	662
Timing of partnership items		**(199)**		(234)		77
Unrealized foreign exchange gain on long-term debt		**(55)**		(7)		(45)
Unrealized risk management activities		**13**		–		44
Asset retirement obligations		**76**		(238)		(321)
Loss carryforwards		**25**		–		25
Deferred PRT		**(132)**		(30)		(5)
PRT deduction for corporate income tax		**78**		19		(6)
Other		**(25)**		(5)		(24)
	$	**31**	$	(30)	$	407

The following table summarizes the movements of the net deferred income tax liability during the year:

		2013		2012		2011
Balance – beginning of year	**$**	**8,174**	$	8,221	$	7,788
Deferred income tax expense (recovery)		**31**		(30)		407
Deferred income tax expense included in other comprehensive income		**–**		4		12
Foreign exchange adjustments		**53**		(21)		20
Business combinations and other		**(75)**		–		(6)
Balance – end of year	**$**	**8,183**	$	8,174	$	8,221

Current income taxes recognized in each operating segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

During 2013, the Government of British Columbia substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $15 million.

During 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax relief on UK North Sea decommissioning expenditures to 50%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $58 million.

During 2011, the UK government enacted legislation to increase the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate from 50% to 62%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $104 million. 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.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's results of operations, financial position or liquidity.

Deferred income tax assets are recognized for temporary differences to the extent that the realization of the related tax benefit through future taxable profits is probable. The Company did not recognize deferred income tax assets with respect to taxable capital loss carryforwards in excess of $1,000 million in North America, which can be carried forward indefinitely and only applied against future taxable capital gains. In addition, the Company has not recognized deferred income tax assets related to tax pools of approximately $700 million, which can only be claimed against income from certain oil and gas properties.

Deferred income tax liabilities have not been recognized on the unremitted net earnings of wholly controlled subsidiaries. The Company is able to control the timing and amount of distributions and no taxes are payable on distributions from these subsidiaries provided that the distributions remain within certain limits.

13. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued

	2013		2012	
Common shares	**Number of shares** (thousands)	**Amount**	Number of shares (thousands)	Amount
Balance – beginning of year	**1,092,072**	**$ 3,709**	1,096,460	$ 3,507
Issued upon exercise of stock options	**5,415**	**130**	6,625	194
Previously recognized liability on stock options exercised for common shares	**–**	**50**	–	45
Purchase of common shares under Normal Course Issuer Bid	**(10,165)**	**(35)**	(11,013)	(37)
Balance – end of year	**1,087,322**	**$ 3,854**	1,092,072	$ 3,709

Preferred Shares

During 2012, the Company amended its Articles by special resolution of the shareholders, changing the designation of its Class 1 preferred shares to "Preferred Shares" which may be issuable in series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions and conditions attached to the shares will be determined by the Board of Directors of the Company.

Dividend Policy

The Company has paid regular quarterly dividends in January, April, July and October of each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 5, 2014, the Board of Directors approved a quarterly dividend of $0.225 per common share, beginning with the dividend payable on April 1, 2014 ($0.20 per common share, approved on November 5, 2013, beginning with the dividend payable on January 1, 2014 and $0.125 per common share, approved on March 6, 2013, beginning with the dividend payable on April 1, 2013). In 2012, the Board of Directors approved a quarterly dividend of $0.105 per common share, beginning with the dividend payable on April 1, 2012.

Normal Course Issuer Bid

In 2013, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the twelve month period commencing April 2013 and ending April 2014, up to 54,635,116 common shares. The Company's Normal Course Issuer Bid announced in 2012 expired April 2013.

During 2013, the Company purchased for cancellation 10,164,800 common shares (2012 – 11,012,700 common shares; 2011 – 3,071,100 common shares) at a weighted average price of $31.46 per common share (2012 – $28.91 per common share; 2011 – $33.68 per common share), for a total cost of $320 million (2012 – $318 million; 2011 – $104 million). Retained earnings were reduced by $285 million (2012 – $281 million; 2011 – $94 million), representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2013, the Company purchased 1,475,000 common shares at a weighted average price of $35.85 per common share for a total cost of $53 million.

Stock Options

The Company's Option Plan provides for the granting of stock options to employees. Stock options granted under the Option Plan have terms ranging from five to six years to expiry and vest over a five-year period. The exercise price of each stock option granted is determined at the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the grant. Each stock option granted provides the holder the choice to purchase one common share of the Company at the stated exercise price or receive a cash payment equal to the difference between the stated exercise price and the market price of the Company's common shares on the date of surrender of the stock option.

The Option Plan is a "rolling 9%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 9% of the common shares outstanding from time to time.

The following table summarizes information relating to stock options outstanding at December 31, 2013 and 2012:

	2013		2012	
	Stock options (thousands)	**Weighted average exercise price**	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	**73,747**	**$ 34.13**	73,486	$ 34.85
Granted	**17,823**	**$ 32.51**	14,779	$ 29.27
Surrendered for cash settlement	**(401)**	**$ 23.83**	(998)	$ 29.82
Exercised for common shares	**(5,415)**	**$ 24.03**	(6,625)	$ 29.19
Forfeited	**(13,013)**	**$ 34.93**	(6,895)	$ 36.68
Outstanding – end of year	**72,741**	**$ 34.36**	73,747	$ 34.13
Exercisable – end of year	**26,632**	**$ 35.27**	29,366	$ 33.73

The range of exercise prices of stock options outstanding and exercisable at December 31, 2013 was as follows:

	Stock options outstanding			**Stock options exercisable**	
Range of exercise prices	**Stock options outstanding** (thousands)	**Weighted average remaining term** (years)	**Weighted average exercise price**	**Stock options exercisable** (thousands)	**Weighted average exercise price**
$ 22.98 - $24.99	3,467	0.27	$ 23.31	3,384	$ 23.30
$ 25.00 - $29.99	13,115	4.17	$ 28.26	2,069	$ 28.30
$ 30.00 - $34.99	28,696	3.67	$ 33.60	7,933	$ 34.28
$ 35.00 - $39.99	15,831	2.99	$ 37.04	6,502	$ 37.02
$ 40.00 - $44.99	9,773	2.14	$ 42.23	5,542	$ 42.24
$ 45.00 - $46.25	1,859	1.79	$ 45.69	1,202	$ 46.01
	72,741	3.20	$ 34.36	26,632	$ 35.27

14. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	2013	2012
Derivative financial instruments designated as cash flow hedges	**$ 81**	$ 86
Foreign currency translation adjustment	**(39)**	(28)
	$ 42	$ 58

15. CAPITAL DISCLOSURES

The Company does not have any externally imposed regulatory capital requirements for managing capital. The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined at each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2013, the ratio was within the target range at 27%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

		2013		2012
Long-term debt [1]	**$**	**9,661**	$	8,736
Total shareholders' equity	**$**	**25,772**	$	24,283
Debt to book capitalization		**27%**		26%

(1) Includes the current portion of long-term debt.

16. NET EARNINGS PER COMMON SHARE

		2013		2012		2011
Weighted average common shares outstanding – basic (thousands of shares)		**1,088,682**		1,097,084		1,095,582
Effect of dilutive stock options (thousands of shares)		**1,859**		2,435		7,000
Weighted average common shares outstanding – diluted (thousands of shares)		**1,090,541**		1,099,519		1,102,582
Net earnings	**$**	**2,270**	$	1,892	$	2,643
Net earnings per common share – basic	**$**	**2.08**	$	1.72	$	2.41
Net earnings per common share – diluted	**$**	**2.08**	$	1.72	$	2.40

In 2013, the Company excluded 65,088,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share.

17. INTEREST AND OTHER FINANCING EXPENSE

		2013		2012		2011
Interest expense:						
Long-term debt	**$**	**457**	$	464	$	450
Other financing expense		**(2)**		(1)		(4)
		455		463		446
Less: amounts capitalized on qualifying assets		**175**		98		59
Total interest and other financing expense		**280**		365		387
Total interest income		**(1)**		(1)		(14)
Net interest and other financing expense	**$**	**279**	$	364	$	373

18. FINANCIAL INSTRUMENTS

The carrying amounts of the Company's financial instruments by category were as follows:

	2013				
Asset (liability)	**Loans and receivables at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 1,427**	**$ –**	**$ –**	**$ –**	**$ 1,427**
Accounts payable	**–**	**–**	**–**	**(637)**	**(637)**
Accrued liabilities	**–**	**–**	**–**	**(2,519)**	**(2,519)**
Other long-term liabilities	**–**	**(39)**	**(97)**	**(56)**	**(192)**
Long-term debt [1]	**–**	**–**	**–**	**(9,661)**	**(9,661)**
	$ 1,427	**$ (39)**	**$ (97)**	**$ (12,873)**	**$ (11,582)**

	2012				
Asset (liability)	Loans and receivables at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 1,197	$ –	$ –	$ –	$ 1,197
Accounts payable	–	–	–	(465)	(465)
Accrued liabilities	–	–	–	(2,273)	(2,273)
Other long-term liabilities	–	4	(261)	(79)	(336)
Long-term debt [1]	–	–	–	(8,736)	(8,736)
	$ 1,197	$ 4	$ (261)	$ (11,553)	$ (10,613)

(1) Includes the current portion of long-term debt.

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt as noted below. The fair values of the Company's recurring other long-term liabilities and fixed rate long-term debt are outlined below:

	2013		
	Carrying amount	**Fair value**	
Asset (liability) [1] [5]		**Level 1**	**Level 2**
Other long-term liabilities	**$ (136)**	**$ –**	**$ (136)**
Fixed rate long-term debt [2] [3] [4]	**(7,883)**	**(8,628)**	**–**
	$ (8,019)	**$ (8,628)**	**$ (136)**

	2012		
	Carrying amount	Fair value	
Asset (liability) [1] [5]		Level 1	Level 2
Other long-term liabilities	$ (257)	$ –	$ (257)
Fixed rate long-term debt [2] [3] [4]	(7,765)	(9,118)	–
	$ (8,022)	$ (9,118)	$ (257)

(1) Excludes financial assets and liabilities where the carrying amount approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities).

(2) The carrying amount of US$350 million of 4.90% notes due December 2014 was adjusted by $9 million (December 31, 2012– $19 million) to reflect the fair value impact of hedge accounting.

(3) The fair value of fixed rate long-term debt has been determined based on quoted market prices.

(4) Includes the current portion of fixed rate long-term debt.

(5) There were no transfers between Level 1 and Level 2 financial instruments.

The following provides a summary of the carrying amounts of derivative financial instruments held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)	2013	2012
Derivatives held for trading		
Crude oil price collars	**$ (33)**	$ (16)
Foreign currency forward contracts	**(3)**	20
Natural gas AECO basis swaps	**(1)**	–
Natural gas AECO put options, net of put premium financing obligations	**(2)**	–
Cash flow hedges		
Foreign currency forward contracts	**(1)**	–
Cross currency swaps	**(96)**	(261)
	$ (136)	$ (257)
Included within:		
Current portion of other long-term liabilities	**$ (38)**	$ (4)
Other long-term liabilities	**(98)**	(253)
	$ (136)	$ (257)

During 2013, the Company recognized a gain of $4 million (2012 – gain of $1 million; 2011 – loss of $2 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value of derivative financial instruments in Level 1 and Level 2 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications. Level 2 fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

Risk Management

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

The changes in estimated fair values of derivative financial instruments included in the risk management liability were recognized in the financial statements as follows:

Asset (liability)	2013	2012
Balance – beginning of year	**$ (257)**	$ (274)
Cost of outstanding put options	**9**	–
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	**(39)**	42
Foreign exchange	**165**	(53)
Other comprehensive income	**(5)**	28
	(127)	(257)
Add: put premium financing obligations [(1)]	**(9)**	–
Balance – end of year	**(136)**	(257)
Less: current portion	**(38)**	(4)
	$ (98)	$ (253)

(1) The Company has negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective options. These obligations are reflected in the risk management liability.

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

	2013	2012	2011
Net realized risk management (gain) loss	**$ (116)**	$ 162	$ 101
Net unrealized risk management loss (gain)	**39**	(42)	(128)
	$ (77)	$ 120	$ (27)

Financial Risk Factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At December 31, 2013, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Price collars [1]	Jan 2014	–	Jun 2014	50,000 bbl/d	US$80.00	–	US$123.09	Brent
	Jan 2014	–	Dec 2014	50,000 bbl/d	US$75.00	–	US$121.57	Brent
	Jan 2014	–	Dec 2014	50,000 bbl/d	US$80.00	–	US$120.17	Brent
	Jan 2014	–	Dec 2014	50,000 bbl/d	US$90.00	–	US$120.10	Brent
	Jan 2015	–	Dec 2015	2,000 bbl/d	US$80.00	–	US$122.55	Brent
	Jan 2014	–	Jun 2014	50,000 bbl/d	US$80.00	–	US$107.84	WTI
	Jan 2014	–	Dec 2014	50,000 bbl/d	US$75.00	–	US$105.54	WTI

(1) Subsequent to December 31, 2013, the Company entered into an additional 50,000 bbl/d of US$80.00 – US$122.09 Brent collars for the period July 2014 to September 2014 and an additional 6,000 bbl/d of US$80.00 – US$122.52 Brent collars for the period January 2015 to December 2015.

	Remaining term			Volume	Weighted average price	Index
Natural gas						
AECO basis swaps				500,000		
	Apr 2014	–	Oct 2014	MMBtu/d	US$0.50	AECO/NYMEX
AECO put options [1]	Apr 2014	–	Oct 2014	470,000 GJ/d	$3.10	AECO

(1) Subsequent to December 31, 2013, the Company entered into an additional 280,000 GJ/d of $3.10 AECO put options for the period April 2014 to October 2014 for a total cost of $6 million.

During 2014, $15 million of put option costs will be settled.

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2013, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt, commercial paper and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At December 31, 2013, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Jan 2014	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2014	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2014	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2014	–	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at December 31, 2013 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2013, the Company had US$2,237 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$500 million designated as cash flow hedges.

Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's 2013 net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2013, resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those sensitivities disclosed in the Company's other continuous disclosure documents, are limited to the impact of changes in a specified variable applied to financial instruments only and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

Increase (decrease)	Impact on net earnings	Impact on other comprehensive income
Commodity price risk		
Increase Brent US$1.00/bbl	**$ (10)**	$ –
Decrease Brent US$1.00/bbl	**$ 10**	$ –
Increase WTI US$1.00/bbl	**$ (5)**	$ –
Decrease WTI US$1.00/bbl	**$ 5**	$ –
Increase AECO/NYMEX basis US$0.10/MMBtu	**$ 9**	$ –
Decrease AECO/NYMEX basis US$0.10/MMBtu	**$ (9)**	$ –
Increase AECO $0.10/Mcf	**$ (1)**	$ –
Decrease AECO $0.10/Mcf	**$ 1**	$ –
Interest rate risk		
Increase interest rate 1%	**$ (8)**	**$ 8**
Decrease interest rate 1%	**$ 6**	**$ (20)**
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	**$ (22)**	$ –
Decrease exchange rate by US$0.01	**$ 22**	$ –

b) Credit risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At December 31, 2013, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At December 31, 2013, the Company had no net risk management assets with specific counterparties related to derivative financial instruments (December 31, 2012 – $18 million).

The carrying amount of financial assets approximates the maximum credit exposure.

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates for financial liabilities are as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 637	$ –	$ –	$ –
Accrued liabilities	$ 2,519	$ –	$ –	$ –
Risk management	$ 38	$ 35	$ 44	$ 19
Other long-term liabilities	$ 21	$ 35	$ –	$ –
Long-term debt [1]	$ 1,436	$ 400	$ 3,107	$ 4,776

(1) Long-term debt represents principal repayments only and does not reflect fair value adjustments, interest, original issue discounts or transaction costs.

19. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2014	2015	2016	2017	2018	Thereafter
Product transportation and pipeline	$ 298	$ 293	$ 225	$ 208	$ 176	$ 1,324
Offshore equipment operating leases and offshore drilling	$ 147	$ 238	$ 81	$ 61	$ 54	$ 17
Office leases	$ 35	$ 41	$ 42	$ 45	$ 47	$ 321
Other	$ 309	$ 172	$ 71	$ 1	$ 1	$ 1

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases of Horizon. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

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

20. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	2013	2012	2011
Changes in non-cash working capital			
Accounts receivable	**$ (243)**	$ 869	$ (198)
Inventory	**(76)**	(9)	(72)
Prepaids and other	**(14)**	(8)	(17)
Accounts payable	**175**	(64)	251
Accrued liabilities	**127**	(138)	627
Current income tax liabilities	**94**	(65)	(83)
Net changes in non-cash working capital	**$ 63**	$ 585	$ 508
Relating to:			
Operating activities	**$ (33)**	$ 447	$ (36)
Financing activities	**(23)**	(37)	(15)
Investing activities	**119**	175	559
	$ 63	$ 585	$ 508

	2013	2012	2011
Expenditures on exploration and evaluation assets	**$ 119**	$ 309	$ 312
Net proceeds on sale of exploration and evaluation assets	**(263)**	–	–
Expenditures on property, plant and equipment	**7,249**	5,804	5,895
Net proceeds on sale of property, plant and equipment	**(38)**	(9)	(6)
Net expenditures on exploration and evaluation assets and property, plant and equipment	**$ 7,067**	$ 6,104	$ 6,201

21. SEGMENTED INFORMATION

The Company's exploration and production activities are conducted in three geographic segments: North America, North Sea and Offshore Africa. These activities include the exploration, development, production and marketing of crude oil, natural gas liquids and natural gas.

The Company's Oil Sands Mining and Upgrading activities are reported in a separate segment from exploration and production activities. The bitumen in the segment is recovered through mining operations.

	Exploration and Production								
	North America			North Sea			Offshore Africa		
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Segmented product sales	**$ 12,659**	$ 11,607	$ 11,806	**$ 805**	$ 928	$ 1,224	**$ 824**	$ 773	$ 946
Less: royalties	**(1,477)**	(1,268)	(1,538)	**(2)**	(2)	(3)	**(137)**	(199)	(114)
Segmented revenue	**11,182**	10,339	10,268	**803**	926	1,221	**687**	574	832
Segmented expenses									
Production	**2,351**	2,165	1,933	**431**	402	412	**191**	163	186
Transportation and blending	**2,939**	2,735	2,301	**6**	10	13	**1**	1	1
Depletion, depreciation and amortization	**3,568**	3,413	2,840	**552**	296	249	**134**	165	242
Asset retirement obligation accretion	**92**	85	70	**35**	27	33	**10**	7	7
Realized risk management activities	**(116)**	162	101	**–**	–	–	**–**	–	–
Horizon asset impairment provision	**–**	–	–	**–**	–	–	**–**	–	–
Insurance recovery – property damage (note 11)	**–**	–	–	**–**	–	–	**–**	–	–
Insurance recovery – business interruption (note 11)	**–**	–	–	**–**	–	–	**–**	–	–
Gain on corporate acquisition/ disposition of properties	**(65)**	–	–	**–**	–	–	**(224)**	–	–
Equity loss from joint venture	**–**	–	–	**–**	–	–	**–**	–	–
Total segmented expenses	**8,769**	8,560	7,245	**1,024**	735	707	**112**	336	436
Segmented earnings (loss) before the following	**$ 2,413**	$ 1,779	$ 3,023	**$ (221)**	$ 191	$ 514	**$ 575**	$ 238	$ 396
Non–segmented expenses									
Administration									
Share-based compensation									
Interest and other financing expense									
Unrealized risk management activities									
Foreign exchange loss (gain)									
Total non–segmented expenses									
Earnings before taxes									
Current income tax expense									
Deferred income tax expense (recovery)									
Net earnings									

Midstream activities include the Company's pipeline operations, an electricity co-generation system and Redwater Partnership. Production activities that are not included in the above segments are reported in the segmented information as other. Inter-segment eliminations include internal transportation and electricity charges.

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. Segment revenue and segment results include transactions between business segments. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred. Sales to external customers are based on the location of the seller.

Operating segments are reported in a manner consistent with the internal reporting provided to the Company's chief operating decision makers.

	Oil Sands Mining and Upgrading			Midstream			Inter–segment elimination and other			Total		
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
	$ 3,631	$ 2,871	$ 1,521	**$ 110**	$ 93	$ 88	**$ (84)**	$ (77)	$ (78)	**$ 17,945**	$ 16,195	$ 15,507
	(184)	(137)	(60)	**–**	–	–	**–**	–	–	**(1,800)**	(1,606)	(1,715)
	3,447	2,734	1,461	**110**	93	88	**(84)**	(77)	(78)	**16,145**	14,589	13,792
	1,567	1,504	1,127	**34**	29	26	**(15)**	(14)	(13)	**4,559**	4,249	3,671
	63	61	62	**–**	–	–	**(71)**	(55)	(50)	**2,938**	2,752	2,327
	582	447	266	**8**	7	7	**–**	–	–	**4,844**	4,328	3,604
	34	32	20	**–**	–	–	**–**	–	–	**171**	151	130
	–	–	–	**–**	–	–	**–**	–	–	**(116)**	162	101
	–	–	396	**–**	–	–	**–**	–	–	**–**	–	396
	–	–	(393)	**–**	–	–	**–**	–	–	**–**	–	(393)
	–	–	(333)	**–**	–	–	**–**	–	–	**–**	–	(333)
	–	–	–	**–**	–	–	**–**	–	–	**(289)**	–	–
	–	–	–	**4**	9	–	**–**	–	–	**4**	9	–
	2,246	2,044	1,145	**46**	45	33	**(86)**	(69)	(63)	**12,111**	11,651	9,503
	$ 1,201	$ 690	$ 316	**$ 64**	$ 48	$ 55	**$ 2**	$ (8)	$ (15)	**4,034**	2,938	4,289
										335	270	235
										135	(214)	(102)
										279	364	373
										39	(42)	(128)
										210	(49)	1
										998	329	379
										3,036	2,609	3,910
										735	747	860
										31	(30)	407
										$ 2,270	$ 1,892	$ 2,643

Capital Expenditures [1]

	2013			2012		
	Net expenditures	**Non-cash and fair value changes**[2]	**Capitalized costs**	Net expenditures	Non-cash and fair value changes[2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	**$ 90**	**$ (84)**	**$ 6**	$ 295	$ (173)	$ 122
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa [3]	**(10)**	**–**	**(10)**	14	–	14
	$ 80	**$ (84)**	**$ (4)**	$ 309	$ (173)	$ 136
Property, plant and equipment						
Exploration and Production						
North America	**$ 3,936**	**$ (450)**	**$ 3,486**	$ 3,831	$ 373	$ 4,204
North Sea	**334**	**(35)**	**299**	254	263	517
Offshore Africa	**114**	**(17)**	**97**	50	17	67
	4,384	**(502)**	**3,882**	4,135	653	4,788
Oil Sands Mining and Upgrading [4]	**2,592**	**(189)**	**2,403**	1,610	142	1,752
Midstream	**197**	**(1)**	**196**	14	–	14
Head office	**38**	**–**	**38**	36	–	36
	$ 7,211	**$ (692)**	**$ 6,519**	$ 5,795	$ 795	$ 6,590

(1) This table provides a reconciliation of capitalized costs including derecognitions and does not include the impact of foreign exchange adjustments.

(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, and other fair value adjustments.

(3) The above noted figures do not include the impact of a pre-tax gain on sale of exploration and evaluation assets totaling $224 million on the Company's disposition of a 50% interest in its exploration right in South Africa during 2013.

(4) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest and share-based compensation.

Segmented Assets

	2013	2012
Exploration and Production		
North America	**$ 29,234**	$ 29,012
North Sea	**1,964**	1,993
Offshore Africa	**981**	924
Other	**25**	36
Oil Sands Mining and Upgrading	**18,604**	16,291
Midstream	**841**	636
Head office	**105**	88
	$ 51,754	$ 48,980

22. REMUNERATION OF DIRECTORS AND SENIOR MANAGEMENT

Remuneration of Non-Management Directors

	2013	2012	2011
Fees earned	**$ 2**	$ 2	$ 2

Remuneration of Senior Management [1]

	2013	2012	2011
Salary	**$ 3**	$ 2	$ 2
Common stock option based awards	**11**	12	18
Annual incentive plans	**3**	3	2
Long-term incentive plans	**14**	9	8
Other compensation	**1**	–	–
	$ 32	$ 26	$ 30

(1) Senior management identified above are consistent with the disclosure on Named Executive Officers provided in the Company's Information Circular to shareholders for the respective years.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

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", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" 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 Management's Discussion and Analysis ("MD&A"), 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, construction of the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast, construction of the proposed Energy East pipeline to transport crude oil from Alberta to Quebec and New Brunswick, the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia, the construction and future operations of the North West Redwater bitumen upgrader and refinery and the "Outlook" section of this MD&A, particularly in reference to the 2014 guidance provided with respect to production and budgeted capital expenditures, 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 natural gas liquids ("NGLs") 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, and the Company's course of action would depend upon its assessment of the future considering all information then available. For additional information, refer to the "Risks and Uncertainties" section of this MD&A.

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

This MD&A 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 International Financial Reporting Standards ("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 this MD&A. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This MD&A of the financial condition and results of operations of the Company should be read in conjunction with the Company's audited consolidated financial statements and related notes for the year ended December 31, 2013.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's consolidated financial statements and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

A Barrel of Oil Equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") 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. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil.

Production volumes and per unit statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of blending costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only.

The Company's 2014 guidance included in this MD&A 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.

The following discussion and analysis refers primarily to the Company's 2013 financial results compared to 2012 and 2011, unless otherwise indicated. In addition, this MD&A details the Company's capital program and outlook for 2014. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2013, its Annual Information Form for the year ended December 31, 2013, and its audited consolidated financial statements for the year ended December 31, 2013 is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. This MD&A is dated March 5, 2014.

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DEFINITIONS AND ABBREVIATIONS

AECO	Alberta natural gas reference location
AIF	Annual Information Form
API	specific gravity measured in degrees on the American Petroleum Institute scale
ARO	asset retirement obligations
bbl	barrels
bbl/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
Bitumen	solid or semi-solid viscous mixture consisting mainly of pentanes and heavier hydrocarbons with viscosity greater than 10,000 centipoise
Brent	Dated Brent
C$	Canadian dollars
CAGR	compound annual growth rate
CAPEX	capital expenditures
CICA	Canadian Institute of Chartered Accountants
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
Crude oil	includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil
CSS	Cyclic Steam Stimulation
EOR	Enhanced Oil Recovery
E&P	Exploration and Production
FPSO	Floating Production, Storage and Offloading Vessel
GHG	greenhouse gas
GJ	gigajoules
GJ/d	gigajoules per day
Horizon	Horizon Oil Sands
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas
Mbbl	thousand barrels
Mbbl/d	thousand barrels per day
MBOE	thousand barrels of oil equivalent
MBOE/d	thousand barrels of oil equivalent per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMcfe	millions of cubic feet equivalent
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
PRT	Petroleum Revenue Tax
SAGD	Steam-Assisted Gravity Drainage
SCO	synthetic crude oil
SEC	United States Securities and Exchange Commission
Tcf	trillion cubic feet
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US GAAP	generally accepted accounting principles in the United States
US$	United States dollars
WCS	Western Canadian Select
WCS Heavy Differential	WCS Heavy Differential from WTI
WTI	West Texas Intermediate reference location at Cushing, Oklahoma

OBJECTIVES AND STRATEGY

The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value (1) on a per common share basis through the development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves. The Company strives to meet these objectives by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a balanced approach to growth and investments and focuses on creating long-term shareholder value. The Company allocates its capital by maintaining:

- § Balance among its products, namely light and medium crude oil and NGLs, Pelican Lake heavy crude oil (2), primary heavy crude oil, bitumen (thermal oil), SCO and natural gas;
- § Balance among near-, mid- and long-term projects;
- § Balance among acquisitions, exploitation and exploration; and
- § Balance between sources and terms of debt financing and maintenance of a strong balance sheet.

(1) Discounted value of crude oil and natural gas reserves plus value of unproved land, less net debt.
(2) Pelican Lake heavy crude oil is 14–17º API oil, which receives medium quality crude netbacks due to lower production costs and lower royalty rates.

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

- § Blending various crude oil streams with diluents to create more attractive feedstock;
- § Supporting and participating in pipeline expansions and/or new additions; and
- § Supporting and participating in projects that will increase the downstream conversion capacity for heavy crude oil.

Operational discipline, safe, effective and efficient operations as well as cost control are fundamental to the Company. By consistently managing costs throughout all cycles of the industry, 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 is committed to maintaining a strong balance sheet and flexible capital structure. The Company believes it has built the necessary financial capacity to complete all of its growth projects. Additionally, the Company's risk management hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs.

Strategic accretive acquisitions are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt financing to selectively acquire properties generating future cash flows in its core areas.

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NET EARNINGS AND CASH FLOW FROM OPERATIONS

Financial Highlights

($ millions, except per common share amounts)		2013	2012	2011
Product sales		**$ 17,945**	$ 16,195	$ 15,507
Net earnings		**$ 2,270**	$ 1,892	$ 2,643
Per common share	– basic	**$ 2.08**	$ 1.72	$ 2.41
	– diluted	**$ 2.08**	$ 1.72	$ 2.40
Adjusted net earnings from operations (1)		**$ 2,435**	$ 1,618	$ 2,540
Per common share	– basic	**$ 2.24**	$ 1.48	$ 2.32
	– diluted	**$ 2.23**	$ 1.47	$ 2.30
Cash flow from operations (2)		**$ 7,477**	$ 6,013	$ 6,547
Per common share	– basic	**$ 6.87**	$ 5.48	$ 5.98
	– diluted	**$ 6.86**	$ 5.47	$ 5.94
Dividends declared per common share (3)		**$ 0.575**	$ 0.42	$ 0.36
Total assets		**$ 51,754**	$ 48,980	$ 47,278
Total long-term liabilities		**$ 20,748**	$ 20,721	$ 20,346
Capital expenditures, net of dispositions		**$ 7,274**	$ 6,308	$ 6,414

(1) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations" presents the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(2) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Cash Flow from Operations" presents certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

(3) On November 5, 2013, the Board of Directors approved a quarterly dividend of $0.20 per common share, beginning with the dividend payable on January 1, 2014 ($0.125 per common share, approved on March 6, 2013, beginning with the dividend payable on April 1, 2013).

Adjusted Net Earnings from Operations

($ millions)		***2013***	*2012*	*2011*
Net earnings as reported		***$ 2,270***	*$ 1,892*	*$ 2,643*
Share-based compensation expense (recovery), net of tax (1)		***135***	*(214)*	*(102)*
Unrealized risk management loss (gain), net of tax (2)		***32***	*(37)*	*(95)*
Unrealized foreign exchange loss, net of tax (3)		***226***	*129*	*215*
Realized foreign exchange gain on repayment of US dollar debt securities, net of tax (4)		***(12)***	*(210)*	*(225)*
Gain on corporate acquisition/disposition of properties, net of tax (5)		***(231)***	*–*	*–*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (6)		***15***	*58*	*104*
Adjusted net earnings from operations		***$ 2,435***	*$ 1,618*	*$ 2,540*

(1) The Company's employee stock option plan provides for a cash payment option. Accordingly, the fair value of the outstanding vested options is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings or are capitalized to Oil Sands Mining and Upgrading construction costs.

(2) Derivative financial instruments are recorded at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.

(3) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, partially offset by the impact of cross currency swaps, and are recognized in net earnings.

(4) During 2013, the Company repaid US$400 million of 5.15% notes. During 2012, the Company repaid US$350 million of 5.45% notes. During 2011, the Company repaid US$400 million of 6.70% notes.

(5) During 2013, the Company recorded an after-tax gain of $231 million related to the acquisition of Barrick Energy Inc. and the disposition of a 50% interest in an exploration right in South Africa.

(6) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. During 2013, the Government of British Columbia substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013, resulting in an increase in the Company's deferred income tax liability of $15 million. During 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax rate relief on UK North Sea decommissioning expenditures to 50%, resulting in an increase in the Company's deferred income tax liability of $58 million. During 2011, the UK government enacted legislation to increase the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%, resulting in an increase in the Company's deferred income tax liability of $104 million.

Cash Flow from Operations

($ millions)	***2013***	*2012*	*2011*
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*	*–*
Deferred income tax expense (recovery)	***31***	*(30)*	*407*
Horizon asset impairment provision	***–***	*–*	*396*
Gain on corporate acquisition/disposition of properties	***(289)***	*–*	*–*
Current income tax on disposition of properties	***58***	*–*	*–*
Insurance recovery – property damage	***–***	*–*	*(393)*
Cash flow from operations	***$ 7,477***	*$ 6,013*	*$ 6,547*

For 2013, the Company reported net earnings of $2,270 million compared with net earnings of $1,892 million for 2012 (2011 – $2,643 million). Net earnings for 2013 included net after-tax expenses of $165 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of a realized foreign exchange gain on repayment of long-term debt, the gain on corporate acquisition/disposition of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities (2012 – $274 million after-tax income; 2011 – $103 million after-tax income). Excluding these items, adjusted net earnings from operations for 2013 increased to $2,435 million from $1,618 million for 2012 (2011 – $2,540 million).

The increase in adjusted net earnings for the year ended December 31, 2013 from the comparable period in 2012 was primarily due to:

§ higher crude oil and NGLs and SCO sales volumes in the North America and Oil Sands Mining and Upgrading segments;
§ higher realized SCO prices;
§ higher natural gas netbacks;
§ higher realized risk management gains; and
§ the impact of a weaker Canadian dollar relative to the US dollar;

partially offset by:

§ higher depletion, depreciation and amortization expense.

The impacts of share-based compensation, risk management activities and changes in foreign exchange rates are expected to continue to contribute to significant volatility in consolidated net earnings and are discussed in detail in the relevant sections of this MD&A.

Cash flow from operations for 2013 increased to $7,477 million ($6.87 per common share) from $6,013 million for 2012 ($5.48 per common share) (2011 – $6,547 million; $5.98 per common share). The increase in cash flow from operations for 2013 from 2012 was primarily due to the factors noted above relating to the increase in adjusted net earnings, excluding depletion, depreciation and amortization expense, as well as due to the impact of cash taxes.

In the Company's Exploration and Production activities, the 2013 average sales price per bbl of crude oil and NGLs increased 2% to average $73.81 per bbl from $72.44 per bbl in 2012 (2011 – $79.16 per bbl), and the average natural gas price increased 33% to average $3.58 per Mcf from $2.70 per Mcf in 2012 (2011 – $3.99 per Mcf). The Company's average sales price of SCO increased 11% to average $100.75 per bbl from $90.74 per bbl in 2012 (2011 – $101.48 per bbl).

Total production of crude oil and NGLs before royalties increased 6% to 478,240 bbl/d from 451,378 bbl/d in 2012 (2011 – 389,053 bbl/d). The increase in crude oil and NGLs production from 2012 was primarily due to strong production in Horizon and Pelican Lake and the impact of the drilling program.

Total natural gas production before royalties decreased 5% to average 1,158 MMcf/d from 1,220 MMcf/d in 2012 (2011 – 1,257 MMcf/d). The decrease in natural gas production was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines.

Total crude oil and NGLs and natural gas production volumes before royalties increased 3% to average 671,162 BOE/d from 654,665 BOE/d in 2012 (2011 – 598,526 BOE/d).

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

($ millions, except per common share amounts)

2013	**Total**	**Dec 31**	**Sep 30**	**Jun 30**	**Mar 31**
Product sales	**$ 17,945**	**$ 4,330**	**$ 5,284**	**$ 4,230**	**$ 4,101**
Net earnings	**$ 2,270**	**$ 413**	**$ 1,168**	**$ 476**	**$ 213**
Net earnings per common share					
– basic	**$ 2.08**	**$ 0.38**	**$ 1.07**	**$ 0.44**	**$ 0.19**
– diluted	**$ 2.08**	**$ 0.38**	**$ 1.07**	**$ 0.44**	**$ 0.19**

2012	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales	$ 16,195	$ 4,059	$ 3,978	$ 4,187	$ 3,971
Net earnings	$ 1,892	$ 352	$ 360	$ 753	$ 427
Net earnings per common share					
– basic	$ 1.72	$ 0.32	$ 0.33	$ 0.68	$ 0.39
– diluted	$ 1.72	$ 0.32	$ 0.33	$ 0.68	$ 0.39

Volatility in the quarterly net earnings over the eight most recently completed quarters was primarily due to:

§ Crude oil pricing – The impact of fluctuating demand, inventory storage levels and geopolitical uncertainties on worldwide benchmark pricing, the impact of the WCS Heavy Differential from WTI in North America and the impact of the differential between WTI and Brent benchmark pricing in the North Sea and Offshore Africa.

§ Natural gas pricing – The impact of fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US.

§ Crude oil and NGLs sales volumes – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, the strong heavy crude oil drilling program, and the impact of the turnaround/suspension and subsequent recommencement of production at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore Africa.

§ Natural gas sales volumes – Fluctuations in production due to the Company's strategic decision to reduce natural gas drilling activity in North America and the allocation of capital to higher return crude oil projects, as well as natural decline rates, shut-in natural gas production due to pricing and the impact and timing of acquisitions.

§ Production expense – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, production and cost optimizations in North America and the turnaround/suspension and subsequent recommencement of production at Horizon.

§ Depletion, depreciation and amortization – Fluctuations due to changes in sales volumes, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, the effect of the planned decommissioning of the Murchison platform in the North Sea, and the impact of the turnaround/suspension and subsequent recommencement of production at Horizon.

§ Share-based compensation – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company's share-based compensation liability.

§ Risk management – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.

§ Foreign exchange rates – Changes in the Canadian dollar relative to the US dollar that impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.

§ Income tax expense – Fluctuations in income tax expense include statutory tax rate and other legislative changes substantively enacted in the various periods.

§ Gains on corporate acquisition/disposition of properties – Fluctuations due to the recognition of gains on corporate acquisitions/dispositions in the third quarter of 2013.

BUSINESS ENVIRONMENT

(Yearly average)		**2013**		2012		2011
WTI benchmark price (US$/bbl)	**$**	**98.00**	$	94.19	$	95.14
Dated Brent benchmark price (US$/bbl)	**$**	**108.62**	$	111.56	$	111.29
WCS blend differential from WTI (US$/bbl)	**$**	**25.11**	$	21.05	$	17.10
WCS blend differential from WTI (%)		**26%**		22%		18%
SCO price (US$/bbl)	**$**	**98.18**	$	92.59	$	103.63
Condensate benchmark price (US$/bbl)	**$**	**101.67**	$	100.92	$	105.38
NYMEX benchmark price (US$/MMBtu)	**$**	**3.67**	$	2.80	$	4.07
AECO benchmark price (C$/GJ)	**$**	**3.00**	$	2.28	$	3.48
US / Canadian dollar average exchange rate (US$)	**$**	**0.9710**	$	1.0004	$	1.0111
US / Canadian dollar year end exchange rate (US$)	**$**	**0.9402**	$	1.0051	$	0.9833

Commodity Prices

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are also highly sensitive to fluctuations in foreign exchange rates. The average value of the Canadian dollar in relation to the US dollar fluctuated significantly throughout 2013, with a high of approximately US$1.02 in January 2013 and a low of approximately US$0.93 in December 2013.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. For 2013, WTI averaged US$98.00 per bbl, an increase of 4% from US$94.19 per bbl for 2012 (2011 – US$95.14 per bbl).

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$108.62 per bbl for 2013, a decrease of 3% from US$111.56 per bbl for 2012 (2011 – US$111.29 per bbl).

WTI and Brent pricing continued to reflect volatility in supply and demand factors and geopolitical events. The Brent differential from WTI tightened for 2013 from 2012 due to a continued debottlenecking of logistical constraints from Cushing to the US Gulf Coast.

The WCS Heavy Differential averaged 26% for 2013 compared with 22% for 2012 (2011 – 18%). The WCS Heavy Differential widened from the comparable periods as a result of decreased heavy oil demand due to planned refinery maintenance, pipeline logistical constraints and third party unplanned refinery disruptions. To partially mitigate its exposure to fluctuating heavy crude oil differentials, as at December 31, 2013, the Company entered into physical crude oil sales contracts with weighted average fixed WCS differentials as follows: 8,000 bbl/d in the first quarter of 2014 at US$21.89 per bbl; 9,000 bbl/d in the second quarter of 2014 at US$21.93 per bbl; and 10,000 bbl/d in the third and fourth quarters of 2014 at US$20.81 per bbl. During December 2013, the WCS Heavy Differential averaged US$38.94 per bbl. Subsequent to December 31, 2013, the WCS Heavy Differential narrowed in January 2014 to average US$29.17 per bbl and in February 2014 to average US$19.14 per bbl. The WCS Heavy Differential is directionally tightening due to increased demand as a result of third party refinery expansion and higher refinery utilization.

The SCO price averaged US$98.18 per bbl in 2013, an increase of 6% from US$92.59 per bbl for 2012 (2011 – US$103.63 per bbl). The increase in SCO pricing was primarily due to the increase in WTI benchmark pricing.

The WCS Heavy Differential is expected to continue to reflect seasonal demand fluctuations, changes in transportation logistics, and refinery utilization and shutdowns.

NYMEX natural gas prices averaged US$3.67 per MMBtu for 2013, an increase of 31% from US$2.80 per MMBtu for 2012 (2011 – US$4.07 per MMBtu). AECO natural gas pricing averaged $3.00 per GJ for 2013, an increase of 32% from $2.28 per GJ for 2012 (2011 – $3.48 per GJ). The higher natural gas pricing in 2013 was primarily due to a return to normal natural gas storage levels.

Operating and Capital Costs

Strong crude oil commodity prices in recent years have resulted in increased demand for oilfield services worldwide. This has led to inflationary operating and capital cost pressures, particularly related to drilling activities and oil sands developments.

Continued cost pressures and changes to environmental regulations may adversely impact the Company's future net earnings, cash flow and capital projects. For additional details, refer to the "Greenhouse Gas and Other Air Emissions" section of this MD&A.

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ANALYSIS OF CHANGES IN PRODUCT SALES

($ millions)	2011	Changes due to Volumes	Changes due to Prices	Changes due to Other	2012	**Changes due to Volumes**	**Changes due to Prices**	**Changes due to Other**	**2013**
North America									
Crude oil and NGLs	$ 10,051	$ 1,055	$ (583)	$ (43)	$ 10,480	**$ 501**	**$ 319**	**$ (54)**	**$ 11,246**
Natural gas	1,755	(42)	(586)	–	1,127	**(67)**	**353**	**–**	**1,413**
	11,806	1,013	(1,169)	(43)	11,607	**434**	**672**	**(54)**	**12,659**
North Sea									
Crude oil and NGLs	1,215	(380)	16	73	924	**(121)**	**4**	**(12)**	**795**
Natural gas	9	(6)	1	–	4	**4**	**2**	**–**	**10**
	1,224	(386)	17	73	928	**(117)**	**6**	**(12)**	**805**
Offshore Africa									
Crude oil and NGLs	878	(207)	36	(8)	699	**38**	**(7)**	**3**	**733**
Natural gas	68	2	4	–	74	**15**	**2**	**–**	**91**
	946	(205)	40	(8)	773	**53**	**(5)**	**3**	**824**
Subtotal									
Crude oil and NGLs	12,144	468	(531)	22	12,103	**418**	**316**	**(63)**	**12,774**
Natural gas	1,832	(46)	(581)	–	1,205	**(48)**	**357**	**–**	**1,514**
	13,976	422	(1,112)	22	13,308	**370**	**673**	**(63)**	**14,288**
Oil Sands Mining and Upgrading	1,521	1,688	(338)	–	2,871	**399**	**361**	**–**	**3,631**
Midstream	88	–	–	5	93	**–**	**–**	**17**	**110**
Intersegment eliminations and other [1]	(78)	–	–	1	(77)	**–**	**–**	**(7)**	**(84)**
Total	$ 15,507	$ 2,110	$ (1,450)	$ 28	$ 16,195	**$ 769**	**$ 1,034**	**$ (53)**	**$ 17,945**

(1) Eliminates internal transportation, electricity charges, and natural gas sales.

Product sales increased 11% to $17,945 million for 2013 from $16,195 million for 2012 (2011 – $15,507 million). The increase was primarily due to higher crude oil and SCO sales volumes in the North America and Oil Sands Mining and Upgrading segments and an increase in realized North America crude oil and NGLs and natural gas prices and Oil Sands Mining and Upgrading SCO prices.

For 2013, 9% of the Company's crude oil and natural gas product sales were generated outside of North America (2012 – 11%; 2011 – 14%). North Sea accounted for 4% of crude oil and natural gas product sales for 2013 (2012 – 6%; 2011 – 8%), and Offshore Africa accounted for 5% of crude oil and natural gas product sales for 2013 (2012 – 5%; 2011 – 6%).

ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2013	2012	2011
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**343,699**	326,829	295,618
North America – Oil Sands Mining and Upgrading	**100,284**	86,077	40,434
North Sea	**18,334**	19,824	29,992
Offshore Africa	**15,923**	18,648	23,009
	478,240	451,378	389,053
Natural gas (MMcf/d)			
North America	**1,130**	1,198	1,231
North Sea	**4**	2	7
Offshore Africa	**24**	20	19
	1,158	1,220	1,257
Total barrels of oil equivalent (BOE/d)	**671,162**	654,665	598,526
Product mix			
Light and medium crude oil and NGLs	**15%**	16%	18%
Pelican Lake heavy crude oil	**7%**	6%	6%
Primary heavy crude oil	**20%**	19%	18%
Bitumen (thermal oil)	**14%**	15%	16%
Synthetic crude oil	**15%**	13%	7%
Natural gas	**29%**	31%	35%
Percentage of gross revenue (1) (2)			
(excluding Midstream revenue)			
Crude oil and NGLs	**90%**	91%	86%
Natural gas	**10%**	9%	14%

(1) Net of blending costs and excluding risk management activities.
(2) Comparative figures have been adjusted to reflect realized prices before transportation costs.

ANALYSIS OF DAILY PRODUCTION, NET OF ROYALTIES

	2013	2012	2011
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**287,428**	273,374	240,006
North America – Oil Sands Mining and Upgrading	**95,098**	82,171	38,721
North Sea	**18,279**	19,772	29,919
Offshore Africa	**12,973**	13,628	20,532
	413,778	388,945	329,178
Natural gas (MMcf/d)			
North America	**1,080**	1,171	1,186
North Sea	**4**	2	7
Offshore Africa	**20**	17	16
	1,104	1,190	1,209
Total barrels of oil equivalent (BOE/d)	**597,835**	587,246	530,576

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), SCO and natural gas.

Total 2013 production averaged 671,162 BOE/d, a 3% increase from 654,665 BOE/d in 2012 (2011 – 598,526 BOE/d).

Total production of crude oil and NGLs before royalties increased 6% to 478,240 bbl/d for 2013 from 451,378 bbl/d in 2012 (2011 – 389,053 bbl/d). The increase in crude oil and NGLs production from 2012 was primarily due to strong production in Horizon and Pelican Lake and the impact of the drilling program. Crude oil and NGLs production for 2013 was slightly below the Company's previously issued guidance of 482,000 to 513,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 29% of the Company's total production in 2013 on a BOE basis. Total natural gas production before royalties decreased 5% to 1,158 MMcf/d for 2013 from 1,220 MMcf/d for 2012 (2011 – 1,257 MMcf/d). The decrease in natural gas production from 2012 was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines. Natural gas production for 2013 slightly exceeded the Company's previously issued guidance of 1,085 to 1,145 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production for 2013 increased 5% to average 343,699 bbl/d from 326,829 bbl/d for 2012 (2011 – 295,618 bbl/d). The increase in production from 2012 was primarily due to strong production in Pelican Lake and the impact of the drilling program.

North America natural gas production for 2013 decreased 6% to average 1,130 MMcf/d from 1,198 MMcf/d in 2012 (2011 – 1,231 MMcf/d). The decrease in natural gas production from 2012 was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines.

North America – Oil Sands Mining and Upgrading

Production averaged 100,284 bbl/d for 2013 compared with 86,077 bbl/d for 2012 (2011 – 40,434 bbl/d). Production in 2013 reflected a continued focus on reliable and efficient operations, and the impact of the successful completion of Horizon's planned maintenance turnaround in May 2013.

North Sea

North Sea crude oil production for 2013 was 18,334 bbl/d, a decrease of 8% from 19,824 bbl/d for 2012 (2011 – 29,992 bbl/d). The decrease in production volumes from 2012 was primarily due to natural field declines, turnaround activities and a previous reduction in drilling activities as a result of an increase in the UK corporate income tax rate in 2011.

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.

Offshore Africa

Offshore Africa crude oil production for 2013 decreased 15% to 15,923 bbl/d from 18,648 bbl/d for 2012 (2011 – 23,009 bbl/d) due to natural field declines and a temporary shut in of the Baobab field in December 2013 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.

Corporate Production Guidance for 2014

The Company targets production levels in 2014 to average between 521,000 bbl/d and 560,000 bbl/d of crude oil and NGLs and between 1,170 MMcf/d and 1,210 MMcf/d of natural gas.

CRUDE OIL INVENTORY VOLUMES

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized on crude oil volumes that were stored in various tanks, pipelines, or FPSOs, as follows:

(bbl)	**2013**	2012	2011
North America – Exploration and Production	**830,673**	643,758	557,475
North America – Oil Sands Mining and Upgrading (SCO)	**1,550,857**	993,627	1,021,236
North Sea	**385,073**	77,018	286,633
Offshore Africa	**185,476**	1,036,509	527,312
	2,952,079	2,750,912	2,392,656

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

		2013		2012		2011
Crude oil and NGLs ($/bbl) [1]						
Sales price [2] [3]	$	**73.81**	$	72.44	$	79.16
Transportation		**2.22**		2.20		1.70
Realized sales price, net of transportation		**71.59**		70.24		77.46
Royalties		**11.13**		10.67		12.30
Production expense		**17.14**		16.11		15.75
Netback	$	**43.32**	$	43.46	$	49.41
Natural gas ($/Mcf) [1]						
Sales price [2] [3]	$	**3.58**	$	2.70	$	3.99
Transportation		**0.28**		0.26		0.26
Realized sales price, net of transportation		**3.30**		2.44		3.73
Royalties		**0.18**		0.09		0.18
Production expense		**1.42**		1.31		1.15
Netback	$	**1.70**	$	1.04	$	2.40
Barrels of oil equivalent ($/BOE) [1]						
Sales price [2] [3]	$	**56.46**	$	52.85	$	58.81
Transportation		**2.10**		2.04		1.65
Realized sales price, net of transportation		**54.36**		50.81		57.16
Royalties		**7.74**		7.07		8.12
Production expense		**14.24**		13.14		12.42
Netback	$	**32.38**	$	30.60	$	36.62

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

ANALYSIS OF PRODUCT PRICES – EXPLORATION AND PRODUCTION

		2013		2012		2011
Crude oil and NGLs ($/bbl) [1] [2] [3]						
North America	$	**69.90**	$	67.93	$	74.05
North Sea	$	**112.46**	$	111.90	$	109.81
Offshore Africa	$	**110.21**	$	111.18	$	105.53
Company average	$	**73.81**	$	72.44	$	79.16
Natural gas ($/Mcf) [1] [2] [3]						
North America	$	**3.43**	$	2.57	$	3.91
North Sea	$	**5.69**	$	5.14	$	3.78
Offshore Africa	$	**10.45**	$	10.31	$	9.70
Company average	$	**3.58**	$	2.70	$	3.99
Company average ($/BOE) [1] [2] [3]	$	**56.46**	$	52.85	$	58.81

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

Realized crude oil and NGLs prices increased 2% to average $73.81 per bbl for 2013 from $72.44 per bbl for 2012 (2011 – $79.16 per bbl). The increase in 2013 was due to higher WTI benchmark pricing and the impact of a weaker Canadian dollar relative to the US dollar.

The Company's realized natural gas price increased 33% to average $3.58 per Mcf for 2013 from $2.70 per Mcf for 2012 (2011 – $3.99 per Mcf). The increase in 2013 was primarily due to a return to normal natural gas storage levels.

North America

North America realized crude oil prices increased 3% to average $69.90 per bbl for 2013 from $67.93 per bbl for 2012 (2011 – $74.05 per bbl). The increase in 2013 was primarily a result of the higher WTI benchmark pricing and the impact of a weaker Canadian dollar relative to the US dollar.

North America realized natural gas prices increased 33% to average $3.43 per Mcf for 2013 from $2.57 per Mcf for 2012 (2011 – $3.91 per Mcf), primarily due to a return to normal natural gas storage levels.

The Company continues to focus on its crude oil marketing strategy including a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil conversion capacity. During 2013, the Company contributed approximately 171,000 bbl/d of heavy crude oil blends to the WCS stream. 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. The Company previously entered into a 20 year transportation agreement to ship 75,000 bbl/d of crude oil on the proposed Kinder Morgan Trans Mountain Expansion from Edmonton, Alberta to Vancouver, British Columbia. The regulatory approval process began in 2013 with a planned in-service date in 2017. The Company has entered into 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.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

(Yearly average)		**2013**		2012		2011
Wellhead Price (1) (2) (3)						
Light and medium crude oil and NGLs (C$/bbl)	**$**	**76.44**	$	72.20	$	83.60
Pelican Lake heavy crude oil (C$/bbl)	**$**	**70.62**	$	68.84	$	74.58
Primary heavy crude oil (C$/bbl)	**$**	**69.06**	$	66.64	$	72.73
Bitumen (thermal oil) (C$/bbl)	**$**	**66.14**	$	66.46	$	69.74
Natural gas (C$/Mcf)	**$**	**3.43**	$	2.57	$	3.91

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

North Sea

North Sea realized crude oil prices averaged $112.46 per bbl for 2013 and were comparable with $111.90 per bbl for 2012 (2011 – $109.81 per bbl). Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting.

Offshore Africa

Offshore Africa realized crude oil prices averaged $110.21 per bbl for 2013 and were comparable with $111.18 per bbl for 2012 (2011 – $105.53 per bbl). Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting.

ROYALTIES – EXPLORATION AND PRODUCTION

		2013		2012		2011
Crude oil and NGLs ($/bbl) [1]						
North America	**$**	**11.30**	$	10.33	$	13.51
North Sea	**$**	**0.33**	$	0.29	$	0.26
Offshore Africa	**$**	**18.18**	$	29.46	$	12.47
Company average	**$**	**11.13**	$	10.67	$	12.30
Natural gas ($/Mcf) [1]						
North America	**$**	**0.14**	$	0.06	$	0.16
Offshore Africa	**$**	**1.83**	$	1.77	$	1.59
Company average	**$**	**0.18**	$	0.09	$	0.18
Company average ($/BOE) [1]	**$**	**7.74**	$	7.07	$	8.12

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

North America

Government royalties on a significant portion of North America crude oil and NGLs production fall under the oil sands royalty regime and are calculated on a project by project basis as a percentage of gross revenue less operating, capital and abandonment costs incurred ("net profit").

Crude oil and NGLs royalties averaged approximately 17% of product sales in 2013 and were comparable with 16% in 2012 (2011 – 19%). North America crude oil and NGLs royalties per bbl are anticipated to average 18% to 20% of product sales for 2014.

Natural gas royalties averaged approximately 5% of product sales for 2013 compared with 3% in 2012 (2011 – 4%) primarily due to higher realized natural gas prices. North America natural gas royalties per Mcf are anticipated to average 7% to 8% of product sales for 2014.

North Sea

The UK government royalties on crude oil were eliminated effective January 1, 2003. The remaining royalty is a gross overriding royalty on the Ninian field.

Offshore Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital and operating costs, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 17% for 2013 compared to 26% for 2012 (2011 – 17%) primarily due to adjustments to royalties during 2012. Offshore Africa royalty rates are anticipated to average 4.5% to 6.5% of product sales for 2014.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

		2013		2012		2011
Crude oil and NGLs ($/bbl) [1]						
North America	**$**	**14.20**	$	13.40	$	13.21
North Sea	**$**	**66.19**	$	53.53	$	37.06
Offshore Africa	**$**	**25.32**	$	23.11	$	20.72
Company average	**$**	**17.14**	$	16.11	$	15.75
Natural gas ($/Mcf) [1]						
North America	**$**	**1.39**	$	1.28	$	1.12
North Sea	**$**	**4.67**	$	3.75	$	2.83
Offshore Africa	**$**	**2.53**	$	2.27	$	2.03
Company average	**$**	**1.42**	$	1.31	$	1.15
Company average ($/BOE) [1]	**$**	**14.24**	$	13.14	$	12.42

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

North America

North America crude oil and NGLs production expense for 2013 increased 6% to $14.20 per bbl from $13.40 per bbl for 2012 (2011 – $13.21 per bbl). The increase in production expense was primarily the result of higher electricity costs, as well as higher servicing costs related to heavy oil activities. North America crude oil and NGLs production expense is anticipated to average $12.50 to $14.50 per bbl for 2014.

North America natural gas production expense for 2013 increased 9% to $1.39 per Mcf from $1.28 per Mcf for 2012 (2011 – $1.12 per Mcf). Natural gas production expense increased from 2012 primarily due to lower production volumes related to the strategic reduction in natural gas activity . North America natural gas production expense is anticipated to average $1.35 to $1.45 per Mcf for 2014.

North Sea

North Sea crude oil production expense for 2013 increased 24% to $66.19 per bbl from $53.53 per bbl for 2012 (2011 – $37.06 per bbl). Production expense increased on a per bbl basis due to the impact of production declines on relatively fixed costs. Production expense is anticipated to average $52.00 to $56.00 per bbl for 2014 due to new drilling activities which are expected to result in additional production from the Ninian fields, and as the Banff FPSO is targeted to return to service early in the third quarter of 2014.

Offshore Africa

Offshore Africa crude oil production expense for 2013 increased 10% to $25.32 per bbl from $23.11 per bbl for 2012 (2011 – $20.72 per bbl). Production expense increased as a result of production declines on relatively fixed costs and the timing of liftings from various fields, which have different cost structures. Offshore Africa crude oil production expense is anticipated to average $38.50 to $42.50 per bbl for 2014 due to timing of liftings from various fields, which have different cost structures, as well as due to lower production.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)		**2013**		2012		2011
North America	**$**	**3,568**	$	3,413	$	2,840
North Sea		**552**		296		249
Offshore Africa		**134**		165		242
Expense	**$**	**4,254**	$	3,874	$	3,331
$/BOE [(1)]	**$**	**20.38**	$	18.65	$	16.35

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

Depletion, depreciation and amortization expense for 2013 increased to $4,254 million from $3,874 million for 2012 (2011 – $3,331 million) primarily due to the effect of the planned cessation of production and decommissioning of the Murchison platform in the North Sea, higher sales volumes in North America and higher overall future development costs.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)		**2013**		2012		2011
North America	**$**	**92**	$	85	$	70
North Sea		**35**		27		33
Offshore Africa		**10**		7		7
Expense	**$**	**137**	$	119	$	110
$/BOE [(1)]	**$**	**0.66**	$	0.57	$	0.54

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

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

The Company continued to focus on reliable and efficient operations throughout 2013. Strong production in 2013 reflected the impact of the successful completion of a planned maintenance turnaround in May 2013.

PRODUCT PRICES, ROYALTIES AND TRANSPORTATION – OIL SANDS MINING AND UPGRADING

($/bbl) [1]		2013		2012		2011
SCO sales price [2]	**$**	**100.75**	$	90.74	$	101.48
Bitumen value for royalty purposes [3]	**$**	**65.48**	$	59.93	$	61.86
Bitumen royalties [4]	**$**	**5.11**	$	4.34	$	3.99
Transportation	**$**	**1.57**	$	1.83	$	1.74

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period of turnaround/suspension of production.
(2) Comparative figures have been adjusted to reflect realized product prices before transportation costs.
(3) Calculated as the quarterly average of the bitumen valuation methodology price.
(4) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices increased 11% to average $100.75 per bbl for 2013 from $90.74 per bbl for 2012 (2011 – $101.48 per bbl), reflecting benchmark pricing and prevailing differentials.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 21 to the Company's consolidated financial statements.

($ millions)		2013		2012		2011
Cash production costs	**$**	**1,567**	$	1,504	$	1,127
Less: costs incurred during the period of turnaround/suspension of production		**(104)**		(154)		(581)
Adjusted cash production costs	**$**	**1,463**	$	1,350	$	546
Adjusted cash production costs, excluding natural gas costs	**$**	**1,359**	$	1,254	$	502
Adjusted natural gas costs		**104**		96		44
Adjusted cash production costs	**$**	**1,463**	$	1,350	$	546

($/bbl) [1]		2013		2012		2011
Adjusted cash production costs, excluding natural gas costs	**$**	**37.68**	$	39.79	$	33.68
Adjusted natural gas costs		**2.89**		3.04		2.96
Adjusted cash production costs	**$**	**40.57**	$	42.83	$	36.64
Sales (bbl/d) [2]		**98,757**		86,153		40,847

(1) Adjusted cash production costs on a per unit basis are based on sales volumes excluding the period of turnaround/suspension of production.
(2) Sales volumes include the period of turnaround/suspension of production.

Adjusted cash production costs averaged $40.57 per bbl for 2013, a decrease of 5% compared with $42.83 per bbl for 2012 (2011 – $36.64 per bbl). The decrease in 2013 adjusted cash production costs per bbl was primarily due to the impact of strong production volumes on a relatively fixed cost structure. Cash production costs are anticipated to average $36.00 to $39.00 per bbl for 2014.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions)		**2013**		2012		2011
Depletion, depreciation and amortization	**$**	**582**	$	447	$	266
Less: depreciation incurred during the period of turnaround/suspension of production		**(79)**		(6)		(64)
Adjusted depletion, depreciation and amortization	**$**	**503**	$	441	$	202
$/bbl [(1)]	**$**	**13.95**	$	13.99	$	13.54

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period of turnaround/suspension of production.

Depletion, depreciation and amortization expense for 2013 increased to $582 million from $447 million for 2012 (2011 – $266 million) primarily due to higher sales volumes and minor asset derecognitions.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

		2013		2012		2011
Expense ($ millions)	**$**	**34**	$	32	$	20
$/bbl [(1)]	**$**	**0.94**	$	1.01	$	1.33

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

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

MIDSTREAM

($ millions)		**2013**		2012		2011
Revenue	**$**	**110**	$	93	$	88
Production expense		**34**		29		26
Midstream cash flow		**76**		64		62
Depreciation		**8**		7		7
Equity loss from joint venture		**4**		9		–
Segment earnings before taxes	**$**	**64**	$	48	$	55

The Company's Midstream assets include three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 85% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The Midstream pipeline assets allow the Company to control the transport of a portion of its own production volumes as well as earn third party revenue. This transportation control enhances the Company's ability to manage the full range of costs associated with the development and marketing of its heavier crude oil.

The Company has a 50% interest in the North West Redwater Partnership ("Redwater Partnership"). Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement. During 2012, the Project received board sanction from Redwater Partnership and its partners.

As at December 31, 2013, Redwater Partnership had interim borrowings of $702 million under credit facilities totaling $1,200 million, with original maturities no later than December 2017. These facilities are secured by a floating charge on the assets of Redwater Partnership with a mandatory repayment required from future financing proceeds. At maturity, under its processing agreement, the Company would be obligated to pay its 25% pro rata share of any shortfall.

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.

Redwater Partnership has entered into various agreements related to the engineering, procurement and construction of the Project. These contracts can be cancelled by Redwater Partnership upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

Subsequent to December 31, 2013, the credit facility maturity date was amended to mature on November 28, 2014. At maturity or at such later date as mutually agreed to by the lenders and Redwater Partnership, the Company will be obligated to repay its 25% pro rata share of any amount outstanding under the facility. As at March 4, 2014, interim borrowings under the facilities were $857 million.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	**2013**	2012	2011
Expense	**$ 335**	$ 270	$ 235
$/BOE (1)	**$ 1.37**	$ 1.13	$ 1.07

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

Administration expense for 2013 increased from 2012 primarily due to higher staffing and general corporate costs.

SHARE-BASED COMPENSATION

($ millions)	**2013**	2012	2011
Expense (Recovery)	**$ 135**	$ (214)	$ (102)

The Company's stock option plan provides current employees with the right to receive common shares or a cash payment in exchange for stock options surrendered.

The share-based compensation liability at December 31, 2013 reflected the Company's liability for awards granted to employees at fair value estimated using the Black-Scholes valuation model. In periods when substantial share price changes occur, the Company's net earnings are subject to significant volatility. The Company utilizes its share-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

The Company recorded a $135 million share-based compensation expense for 2013, primarily as a result of remeasurement of the fair value of outstanding stock options at the end of the year related to an increase in the Company's share price, together with the impact of normal course graded vesting of stock options granted in prior periods and the impact of vested stock options exercised or surrendered during the year. During 2013, the Company capitalized $25 million of share-based compensation expense to property, plant and equipment in the Oil Sands Mining and Upgrading segment (2012 – $12 million recovery; 2011 – $ nil).

During 2013, the Company paid $4 million for stock options surrendered for cash settlement (2012 – $7 million; 2011 – $14 million).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	**2013**	2012	2011
Expense, gross	**$ 454**	$ 462	$ 432
Less: capitalized interest	**175**	98	59
Expense, net	**$ 279**	$ 364	$ 373
$/BOE (1)	**$ 1.14**	$ 1.52	$ 1.71
Average effective interest rate	**4.4%**	4.8%	4.7%

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

Gross interest and other financing expense for 2013 were comparable to 2012. Capitalized interest of $175 million for 2013 was related to the Horizon Phase 2/3 expansion and the Kirby Thermal Oil Sands Project.

The Company's average effective interest rate for 2013 decreased from 2012 primarily due to the repayment of $400 million of 4.50% medium-term notes and US$400 million of 5.15% notes during the first quarter of 2013 and US$350 million of 5.45% notes in the fourth quarter of 2012 as well as due to an increase in the utilization of the lower cost US commercial paper program that was implemented in March 2013.

RISK MANAGEMENT ACTIVITIES

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

($ millions)		**2013**		2012		2011
Crude oil and NGLs financial instruments	**$**	**44**	$	65	$	117
Foreign currency contracts		**(160)**		97		(16)
Realized (gain) loss	**$**	**(116)**	$	162	$	101
Crude oil and NGLs financial instruments	**$**	**17**	$	3	$	(134)
Natural gas financial instruments		**3**		–		–
Foreign currency contracts		**19**		(45)		6
Unrealized loss (gain)	**$**	**39**	$	(42)	$	(128)
Net (gain) loss	**$**	**(77)**	$	120	$	(27)

During 2013, net realized risk management gains were related to the settlement of foreign currency and crude oil contracts. The Company recorded a net unrealized loss of $39 million ($32 million after-tax) on its risk management activities (2012 – $42 million unrealized gain, $37 million after-tax; 2011 – $128 million unrealized gain, $95 million after-tax), primarily related to changes in the fair value of these contracts.

The cash settlement amount of commodity and foreign currency derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices and foreign exchange rates at the time of final settlement, as compared to their fair value at December 31, 2013.

Complete details related to outstanding derivative financial instruments at December 31, 2013 are disclosed in note 18 to the Company's consolidated financial statements.

FOREIGN EXCHANGE

($ millions)		**2013**		2012		2011
Net realized gain	**$**	**(16)**	$	(178)	$	(214)
Net unrealized loss [(1)]		**226**		129		215
Net loss (gain)	**$**	**210**	$	(49)	$	1

(1) Amounts are reported net of the hedging effect of cross currency swaps.

The Company's operating results are affected by the fluctuations in the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. Predominantly all of the Company's revenue is based on reference to US dollar benchmark prices. An increase in the value of the Canadian dollar in relation to the US dollar results in decreased revenue from the sale of the Company's production. Conversely a decrease in the value of the Canadian dollar in relation to the US dollar results in increased revenue from the sale of the Company's production. Production expenses in the North Sea are subject to foreign currency fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar. The value of the Company's US dollar denominated debt is also impacted by the value of the Canadian dollar in relation to the US dollar.

The net realized foreign exchange gain for 2013 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$400 million of 5.15% notes. The net unrealized foreign exchange loss in 2013 was primarily related to the impact of a weaker Canadian dollar with respect to remaining US dollar debt and the reversal of the life-to-date unrealized foreign exchange gain on the repayment of US$400 million of 5.15% notes. Included in the net unrealized loss for 2013 was an unrealized gain of $165 million (2012 – $53 million unrealized loss, 2011 – $42 million unrealized gain) related to the impact of cross currency swaps. The US/Canadian dollar exchange rate at December 31, 2013 was US$0.9402 (December 31, 2012 – US$1.0051; December 31, 2011 – US$0.9833).

INCOME TAXES

($ millions, except income tax rates)	2013	2012	2011
North America [1]	**$ 544**	$ 366	$ 315
North Sea	**23**	115	245
Offshore Africa [2]	**202**	206	140
PRT (recovery) expense – North Sea	**(56)**	44	135
Other taxes	**22**	16	25
Current income tax expense	**735**	747	860
Deferred income tax expense	**163**	–	412
Deferred PRT recovery – North Sea	**(132)**	(30)	(5)
Deferred income tax expense (recovery)	**31**	(30)	407
	766	717	1,267
Income tax rate and other legislative changes	**(15)**	(58)	(104)
	$ 751	$ 659	$ 1,163
Effective income tax rate on adjusted net earnings from operations [3]	**26.2%**	27.8%	27.7%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.
(2) Includes current income taxes relating to disposition of properties.
(3) Excludes the impact of current and deferred PRT expense and other current income tax expense.

Current income taxes recognized in each operating segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

During 2013, the Government of British Columbia substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $15 million.

During 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax relief on UK North Sea decommissioning expenditures to 50%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $58 million.

During 2011, the UK government enacted legislation to increase the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate from 50% to 62%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $104 million.

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 included a five-year transition provision and had no impact on net earnings.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's results of operations, financial position or liquidity.

During 2013, the Company filed Scientific Research and Experimental Development claims of approximately $390 million (2012 – $300 million; 2011 – $210 million) relating to qualifying research and development capital and operating expenditures for Canadian income tax purposes.

For 2014, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $675 million to $775 million in Canada and recoveries of $40 million to $60 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	2013	2012	2011
Exploration and Evaluation			
Net (proceeds) expenditures [2] [3]	**$ (144)**	$ 309	$ 312
Property, Plant and Equipment			
Net property acquisitions [2]	**246**	144	1,012
Well drilling, completion and equipping	**2,140**	1,902	1,878
Production and related facilities	**1,878**	1,978	1,690
Capitalized interest and other [4]	**120**	111	104
Net expenditures	**4,384**	4,135	4,684
Total Exploration and Production	**4,240**	4,444	4,996
Oil Sands Mining and Upgrading			
Horizon Phases 2/3 construction costs	**2,057**	1,315	481
Sustaining capital	**278**	223	170
Turnaround costs	**100**	21	79
Capitalized interest and other [4]	**157**	51	48
Total Oil Sands Mining and Upgrading	**2,592**	1,610	778
Horizon coker rebuild and collateral damage costs [5]	**–**	–	404
Midstream	**197**	14	5
Abandonments [6]	**207**	204	213
Head office	**38**	36	18
Total net capital expenditures	**$ 7,274**	$ 6,308	$ 6,414
By segment			
North America [2]	**$ 4,026**	$ 4,126	$ 4,736
North Sea	**334**	254	227
Offshore Africa [3]	**(120)**	64	33
Oil Sands Mining and Upgrading [5]	**2,592**	1,610	1,182
Midstream	**197**	14	5
Abandonments [6]	**207**	204	213
Head office	**38**	36	18
Total	**$ 7,274**	$ 6,308	$ 6,414

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.
(2) Includes Business Combinations.
(3) Includes proceeds from the Company's disposition of a 50% interest in its exploration right in South Africa.
(4) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.
(5) During 2011, the Company recognized $393 million of property damage insurance recoveries (see note 11 to the Company's consolidated financial statements), offsetting the costs incurred related to the coker rebuild and collateral damage costs.
(6) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core areas. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for 2013 were $7,274 million compared with $6,308 million for 2012 (2011 – $6,414 million). The increase in 2013 capital expenditures from 2012 was primarily due to the ramp up of Horizon Phase 2/3 site construction activity, the Horizon turnaround completed in the second quarter of 2013, increased well drilling and completions spending, increased Midstream spending related to pipeline construction activity, and the acquisition of Barrick Energy Inc., partially offset by the disposition of a 50% interest in Block 11B/12B in South Africa and lower spending associated with the completion of the construction of the Kirby South Project.

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, resulting in an after-tax gain on sale of exploration and evaluation property of $166 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.

Subsequent to December 31, 2013, 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. It is the Company's intention to finance the transaction utilizing cash flow from operations generated in excess of capital expenditures and available bank credit facilities, including the new unsecured bank credit facility, while maintaining the ongoing dividend program.

Drilling Activity (number of wells)	**2013**	2012	2011
Net successful natural gas wells	**44**	35	83
Net successful crude oil wells (1)	**1,117**	1,203	1,103
Dry wells	**30**	33	48
Stratigraphic test / service wells	**384**	727	657
Total	**1,575**	1,998	1,891
Success rate (excluding stratigraphic test / service wells)	**97%**	97%	96%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 59% of the total capital expenditures for 2013 compared to approximately 69% for 2012 (2011 – 77%).

During 2013, the Company targeted 45 net natural gas wells, including 28 wells in Northeast British Columbia, 14 wells in Northwest Alberta and 3 wells in Northern Plains. The Company also targeted 1,145 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 859 primary heavy crude oil wells, 37 Pelican Lake heavy crude oil wells, 145 bitumen (thermal oil) wells and 1 light crude oil well were drilled. Another 103 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company continued to access its large crude oil drilling inventory to maximize value in both the short and long term. Due to the Company's focus on drilling crude oil wells in recent years and low natural gas prices, natural gas drilling activities have been reduced from historical levels. Deferred natural gas well locations have been retained in the Company's prospect inventory.

Overall Primrose thermal production for 2013 averaged approximately 96,000 bbl/d, compared with approximately 99,000 bbl/d in 2012 (2011 – 98,000 bbl/d). Production volumes were in line with expectations due to the cyclic nature of thermal production at Primrose.

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 next planned phase of the Company's in situ Oil Sands assets expansion is the Kirby South Project. Site construction is complete and first steam injection was achieved 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.

Development of the tertiary recovery conversion projects at Pelican Lake continued and 37 horizontal wells were drilled during 2013. Pelican Lake production averaged approximately 43,000 bbl/d in 2013 (2012 and 2011 – 38,000 bbl/d). The new 20,000 bbl/d battery was completed in the first half of 2013, alleviating the previous facility constraints at Pelican Lake and Woodenhouse. Further ramp up of production is anticipated in early 2014.

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 by 2016.

For 2014, the Company's overall planned drilling activity in North America is targeted to be 1,008 net crude oil wells, 15 net bitumen wells and 61 net natural gas wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in 2013 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.

North Sea

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 mitigated through receipt of business interruption insurance proceeds.

In 2012, the UK government announced the implementation of the Brownfield Allowance, which allows for an agreed allowance for certain pre-approved qualifying field developments. This allowance partially mitigates the impact of previous supplementary income tax increases. During 2013, the Company received Brownfield Allowance approvals for the Tiffany and Ninian fields. At the Tiffany field, the Company completed 1 injection well conversion and drilled 1 production well with production of approximately 1,500 bbl/d, exceeding original forecasted volumes. The Company 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 was introduced in 2013 and 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

During 2013, the Company contracted a drilling rig for a 6 well drilling program at the Baobab field in Côte d'Ivoire. The rig is expected to arrive in country no later than the first quarter of 2015. At the Espoir field, the Company is seeking a drilling rig and is assessing the opportunity to commence drilling in the latter half of 2014.

Exploration activities continue to progress in both Côte d'Ivoire and South Africa. In Côte d'Ivoire, the operator in Block CI-514 is expected to commence drilling 1 exploratory well in March 2014. In South Africa, the operator is targeting to commence drilling 1 exploratory well in the third quarter of 2014.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**2013**		2012		2011
Working capital deficit [1]	**$**	**1,574**	$	1,264	$	894
Long-term debt [2] [3]	**$**	**9,661**	$	8,736	$	8,571
Shareholders' equity						
Share capital	**$**	**3,854**	$	3,709	$	3,507
Retained earnings		**21,876**		20,516		19,365
Accumulated other comprehensive income		**42**		58		26
Total	**$**	**25,772**	$	24,283	$	22,898
Debt to book capitalization [3] [4]		**27%**		26%		27%
Debt to market capitalization [3] [5]		**20%**		22%		17%
After-tax return on average common shareholders' equity [6]		**9%**		8%		12%
After-tax return on average capital employed [3] [7]		**7%**		7%		10%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.
(2) Includes the current portion of long-term debt (2013 – $1,444 million; 2012 – $798 million; 2011 – $359 million).
(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.
(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.
(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus current and long-term debt.
(6) Calculated as net earnings for the twelve month trailing period; as a percentage of average common shareholders' equity for the year.
(7) Calculated as net earnings plus after-tax interest and other financing expense for the twelve month trailing period; as a percentage of average capital employed for the year.

At December 31, 2013, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of this MD&A. In addition, the Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

During 2013, the Company established a US commercial paper program. Borrowings of up to a maximum US$1,500 million are authorized. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

At December 31, 2013, the Company had in place bank credit facilities of $4,801 million, of which approximately $2,937 million, net of commercial paper issuances of $532 million, was available.

At December 31, 2013, the Company has maturities of long-term debt aggregating $912 million over the next 12 months (US$500 million due November 2014; US$350 million due December 2014). It is the Company's intention to retire this indebtedness utilizing cash flow from operations generated in excess of capital expenditures and available bank credit facilities as necessary, while maintaining the ongoing dividend program. On a pro forma basis, reflecting the retirement of this indebtedness, the available credit under its bank credit facilities at December 31, 2013 would amount to $2,025 million.

During 2013, the Company repaid $400 million of 4.50% medium-term notes and US$400 million of 5.15% notes. The $3,000 million revolving syndicated credit facility was extended to June 2017. Additionally, the Company issued $500 million of 2.89% medium-term notes due August 2020. Proceeds from the securities issued were used to repay bank indebtedness and for general corporate purposes.

During 2013, the Company filed base shelf prospectuses that allow for the issue of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until December 2015. If issued, these securities will bear interest as determined at the date of issuance.

Long-term debt was $9,661 million at December 31, 2013, resulting in a debt to book capitalization ratio of 27% (December 31, 2012 – 26%; December 31, 2011 – 27%). This ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operations is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. The Company has hedged a portion of its production for 2014 and 2015 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs. Further details related to the Company's long-term debt at December 31, 2013 are discussed in note 9 to the Company's consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. As at March 5, 2014, an average of approximately 272,000 bbl/d of currently forecasted 2014 crude oil volumes and approximately 8,000 bbl/d of currently forecasted 2015 crude oil volumes were hedged using price collars and physical crude oil sales contracts with fixed WCS differentials. An additional 500,000 MMBtu/d of natural gas volumes were hedged for April 2014 to October 2014 using AECO basis swaps. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2013 are discussed in note 18 to the Company's consolidated financial statements.

Share Capital

As at December 31, 2013, there were 1,087,322,000 common shares outstanding and 72,741,000 stock options outstanding. As at March 4, 2014, the Company had 1,090,824,000 common shares outstanding and 69,845,000 stock options outstanding.

During 2012, the Company amended its Articles by special resolution of the shareholders, changing the designation of its Class 1 preferred shares to "Preferred Shares" which may be issuable in series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions and conditions attached to the shares will be determined by the Board of Directors of the Company.

On March 5, 2014, the Company's Board of Directors approved an increase in the annual dividend to $0.90 per common share (previous annual dividend rate of $0.80 per common share), beginning with the quarterly dividend payable on April 1, 2014 at $0.225 per common share. This represents a 13% increase from the previous quarterly dividend, reflecting the stability of the Company's cash flow and providing a return to shareholders. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

During 2013, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the TSX and the NYSE, during the twelve month period commencing April 2013 and ending April 2014, up to 54,635,116 common shares. The Company's Normal Course Issuer Bid announced in 2012 expired April 2013.

During 2013, the Company purchased for cancellation 10,164,800 common shares at a weighted average price of $31.46 per common share for a total cost of $320 million. Retained earnings were reduced by $285 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2013, the Company purchased 1,475,000 common shares at a weighted average price of $35.85 per common share for a total cost of $53 million.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. As at December 31, 2013, no entities were consolidated under IFRS 10, "Consolidated Financial Statements". The following table summarizes the Company's commitments as at December 31, 2013:

($ millions)	2014	2015	2016	2017	2018	Thereafter
Product transportation and pipeline	$ 298	$ 293	$ 225	$ 208	$ 176	$ 1,324
Offshore equipment operating leases and offshore drilling	$ 147	$ 238	$ 81	$ 61	$ 54	$ 17
Long-term debt (1)	$ 1,436	$ 400	$ 931	$ 1,750	$ 426	$ 4,776
Interest and other financing expense (2)	$ 441	$ 405	$ 387	$ 323	$ 270	$ 3,803
Office leases	$ 35	$ 41	$ 42	$ 45	$ 47	$ 321
Other	$ 309	$ 172	$ 71	$ 1	$ 1	$ 1

(1) Long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs.

(2) Interest and other financing expense amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at December 31, 2013.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases of Horizon. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

RESERVES

For the years ended December 31, 2013, 2012 and 2011, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's proved and proved plus probable crude oil, NGLs and natural gas 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 FASB Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual Form 40-F filed with the SEC and in the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

The following tables summarize the company gross proved and proved plus probable reserves using forecast prices and costs as at December 31, 2013, prepared in accordance with NI 51-101 reserves disclosures:

Proved 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)
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**

Proved plus Probable 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)
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**

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.

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.

Additional reserves disclosure is annually disclosed in the AIF and the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

RISKS AND UNCERTAINTIES

The Company is exposed to various operational risks inherent in the exploration, development, production and marketing of crude oil and NGLs and natural gas and the mining and upgrading of bitumen into SCO. These inherent risks include, but are not limited to, the following:

- The ability to find, produce and replace reserves, whether sourced from exploration, improved recovery or acquisitions, at a reasonable cost, including the risk of reserve revisions due to economic and technical factors. Reserve revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Reservoir quality and uncertainty of reserve estimates;
- Volatility in the prevailing prices of crude oil and NGLs and natural gas;
- Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
- Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas;
- Timing and success of integrating the business and operations of acquired properties and/or companies;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
- Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
- Foreign exchange risk due to fluctuating exchange rates on the Company's US dollar denominated debt and as all sales are predominantly based on US dollar denominated benchmarks;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;
- Future legislative and regulatory developments related to environmental regulation;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations;
- Changing royalty regimes;
- Business interruptions because of unexpected events such as fires or explosions whether caused by human error or nature, severe storms and other calamitous acts of nature, blowouts, freeze-ups, mechanical or equipment failures of facilities and infrastructure and other similar events affecting the Company or other parties whose operations or assets directly or indirectly impact the Company and that may or may not be financially recoverable;
- The access to markets for the Company's products; and
- Other circumstances affecting revenue and expenses.

The Company uses a variety of means to help mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. Derivative financial instruments are utilized to help ensure targets are met and to manage commodity price, foreign currency and interest rate exposures. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with substantially all investment grade financial institutions and other entities. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

For additional details regarding the Company's risks and uncertainties, refer to the Company's AIF for the year ended December 31, 2013.

ENVIRONMENT

The Company continues to invest in people, technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner.

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 require the Company to address and mitigate the effect of its activities on the environment. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings and cash flow from operations.

The Company's associated 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's environmental risk management strategies employ an Environmental Management Plan (the "Plan"). Details of the Plan, along with performance results, are presented to, and reviewed by, the Board of Directors quarterly.

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

— 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 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");
— CO_2 reduction programs including the injection of CO_2 into tailings and for use in EOR;
— A program in place related to progressive reclamation and tailings management at Horizon; and
— Participation and support for the Joint Oil Sands Monitoring Program.

For 2013, the Company's capital expenditures included $207 million for abandonment expenditures (2012 – $204 million; 2011 – $213 million). The Company's estimated discounted ARO at December 31, 2013 was as follows:

($ millions)		**2013**		2012
Exploration and Production				
North America	**$**	**1,707**	$	2,079
North Sea		**1,090**		1,030
Offshore Africa		**225**		218
Oil Sands Mining and Upgrading		**1,138**		937
Midstream		**2**		2
	$	**4,162**	$	4,266

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.

GREENHOUSE GAS AND OTHER AIR EMISSIONS

The Company, through the Canadian Association of Petroleum Producers, is working with Canadian legislators and regulators as they develop and implement new GHG emission laws and regulations. Internally, the Company is pursuing an integrated emissions reduction strategy, to ensure that it is able to comply with existing and future 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.

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.

In the Province of Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e 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 the regulations in 2016. In the Province of British Columbia, carbon tax is currently being assessed at $30/tonne of CO_2e on fuel consumed and gas flared in the province. The province of Saskatchewan released draft GHG regulations that regulate facilities emitting more than 50 kilotonnes of CO_2e 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_2 allocation. In Phase 2 (2008 – 2012) the Company's CO_2 allocation was decreased below the Company's operations emissions. In Phase 3 (2013 – 2020) the Company's CO_2 allocation was further reduced. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

The United States Environmental Protection Agency ("EPA") is proceeding to regulate GHGs under the Clean Air Act. This EPA action has been 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 decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oil with higher emissions intensity.

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 emission 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_2 capture and sequestration in oil sands tailings, CO_2 capture and storage in association with EOR, participation in an industry initiative to promote an integrated CO_2 capture and storage network, and participation in organizations that are researching technologies to reduce GHG emissions (specifically COSIA and Carbon Management Canada).

The additional requirements of enacted or proposed GHG regulations on the Company's operations will increase capital expenditures and operating expenses, including those related to Horizon and the Company's other existing and certain planned oil sands projects. This may have an adverse effect on the Company's future net earnings and cash flow from operations.

Air pollutant standards and guidelines are being developed federally and provincially and the Company is participating in these discussions. Ambient air quality and sector based reductions in air emissions are being reviewed. Through 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.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material.

Critical accounting policies and estimates are reviewed by the Company's Audit Committee annually. The Company believes the following are the most critical accounting policies and estimates in preparing its consolidated financial statements.

Depletion, Depreciation and Amortization and Impairment

Exploration and evaluation ("E&E") costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. The judgements associated with the estimation of proved reserves are described below in "Crude Oil and Natural Gas Reserves".

An alternative acceptable accounting method for E&E costs under IFRS 6 "Exploration for and Evaluation of Mineral Resources" is to charge exploratory dry holes and geological and geophysical exploration costs incurred after having obtained the legal rights to explore an area against net earnings in the period incurred rather than capitalizing to E&E assets.

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of Cash Generating Units ("CGUs"), aggregated at the segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices, discount rates and income taxes as well as development and production costs. Changes in any of these assumptions, such as a downward revision in probable reserves volumes, decrease in commodity prices or increase in costs, could impact the fair value.

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Crude oil and natural gas properties in the Exploration and Production segments are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future estimated development expenditures required to develop proved reserves. Estimates of proved reserves have a significant impact on net earnings, as they are a key input to the calculation of depletion expense.

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low commodity prices for an extended period, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If any such indication of impairment exists, the Company performs an impairment test related to the specific assets at the CGU level.

Crude Oil and Natural Gas Reserves

Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties, interpretations, and judgements. The Company expects that, over time, its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserve estimates would result in a higher or lower depletion, depreciation and amortization charge to net earnings. Downward revisions to reserve estimates may also result in an impairment of E&E and property, plant and equipment carrying amounts.

Asset Retirement Obligations

The Company is required to recognize a liability for ARO associated with its property, plant and equipment. An ARO liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total ARO amount. These individual assumptions can be subject to change.

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's weighted average credit-adjusted risk-free interest rate, which is currently 5.0%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted as at the date of the balance sheet. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes liabilities for potential tax audit issues based on assessments of whether additional taxes will likely be due.

Risk Management Activities

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The carrying amount of a risk management liability is adjusted for the Company's own credit risk. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

Purchase Price Allocations

Purchase prices related to business combinations and asset acquisitions are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation and amortization expense and impairment tests.

The Company has made various assumptions in determining the fair values of the acquired assets and liabilities. The most significant assumptions and judgements relate to the estimation of the fair value of the crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates crude oil and natural gas reserves. Reserve estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgements associated with these estimated reserves are described above in "Crude Oil and Natural Gas Reserves". Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

Share-Based Compensation

The Company has made various assumptions in estimating the fair values of stock options granted including expected volatility, expected exercise behavior and future forfeiture rates. At each period end, stock options outstanding are remeasured for subsequent changes in the fair value of the liability.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2013, the Company adopted the following new accounting standards issued by the IASB:

a) IFRS 10 “Consolidated Financial Statements” replaced IAS 27 “Consolidated and Separate Financial Statements” (IAS 27 still contains guidance for Separate Financial Statements) and Standing Interpretations Committee (“SIC”) 12 “Consolidation – Special Purpose Entities”. IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on applying the control principle to determine whether an investor controls an investee.

   IFRS 11 “Joint Arrangements” replaced IAS 31 “Interests in Joint Ventures” and SIC 13 “Jointly Controlled Entities – Non-Monetary Contributions by Venturers”. The new standard defines two types of joint arrangements, joint operations and joint ventures. In a joint operation, the parties with joint control have rights to the assets and obligations for the liabilities of the joint arrangement and are required to recognize their proportionate interest in the assets, liabilities, revenues and expenses of the joint arrangement. In a joint venture, the parties have an interest in the net assets of the arrangement and are required to apply the equity method of accounting.

   IFRS 12 “Disclosure of Interests in Other Entities”. The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities.

   The Company adopted these standards retrospectively. Adoption of these standards did not have a material impact on the Company’s consolidated financial statements.

b) IFRS 13 “Fair Value Measurement” provides guidance on the application of fair value where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value. IFRS 13 was adopted prospectively. As a result of adoption of this standard, the Company has included its own credit risk in measuring the carrying amount of a risk management liability with no material impact on the Company’s consolidated financial statements.

c) Amendments to IAS 1 “Presentation of Financial Statements” require items of other comprehensive income that may be reclassified to net earnings to be grouped together. The amendments also require that items in other comprehensive income and net earnings be presented as either a single statement or two consecutive statements. Adoption of this amended standard impacted presentation only.

d) IFRS Interpretation Committee (“IFRIC”) 20 “Stripping Costs in the Production Phase of a Surface Mine” requires overburden removal costs during the production phase to be capitalized and depreciated if the Company can demonstrate that probable future economic benefits will be realized, the costs can be reliably measured, and the Company can identify the component of the ore body for which access has been improved. Adoption of this standard did not have a material impact on the Company’s consolidated financial statements.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In November 2013, the IASB issued amendments to IFRS 9 “Financial Instruments” to provide guidance on hedge accounting and associated disclosures as part of its overall Financial Instruments project to replace IAS 39 “Financial Instruments – Recognition and Measurement”. The new hedge accounting guidance in IFRS 9 replaces strict quantitative tests of effectiveness with less restrictive assessments of how well the hedging instrument accomplishes the Company’s risk management objectives for financial and non-financial risk exposures. The new guidance also allows entities to hedge components of non-financial items.

Previous amendments to IFRS 9 replaced the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income.

As part of the November 2013 amendments to IFRS 9, the IASB removed the January 1, 2015 mandatory effective date, and did not provide a new mandatory effective date. However, entities may still choose to apply IFRS 9 immediately.

Effective January 1, 2014, the Company adopted IFRS 9 with no material impact on the Company’s consolidated financial statements.

CONTROL ENVIRONMENT

The Company's management, including the President and the Chief Financial Officer and Senior Vice-President, Finance, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2013, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized and reported within the time periods specified and such information is accumulated and communicated to the Company's management to allow timely decisions regarding required disclosures.

The Company's management also performed an assessment of internal control over financial reporting as at December 31, 2013, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2013 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal control over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems 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.

OUTLOOK

The Company continues to implement its strategy of maintaining a large portfolio of varied projects, which the Company believes will enable it, over an extended period of time, to provide consistent growth in production and create shareholder value. Annual budgets are developed, scrutinized throughout the year and revised if necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas.

The Company's 2014 guidance included in this MD&A 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. The Company targets production levels in 2014 to average between 521,000 bbl/d and 560,000 bbl/d of crude oil and NGLs and between 1,170 MMcf/d and 1,210 MMcf/d of natural gas.

Capital expenditures in 2014 are currently targeted to be as follows:

($ millions)	2014 Guidance
Exploration and Production	
North America natural gas	$ 590
North America crude oil	1,990
International crude oil	750
Thermal In Situ Oil Sands	
Primrose and Future	600
Kirby South	80
Kirby North Phase 1	450
Midstream	110
Property acquisitions, dispositions and other	25
Total Exploration and Production	$ 4,595
Oil Sands Mining and Upgrading	
Project Capital	
Reliability – Tranche 2	40
Directive 74	200
Phase 2A	100
Phase 2B	1,325 - 1,575
Phase 3	550 - 700
Owner's Costs and Other	305
Total Capital Projects	$2,520 - 2,920
Technology	10
Phase 4	25
Sustaining capital	260
Turnarounds and reclamation	40
Capitalized interest and other	290
Total Oil Sands Mining and Upgrading	$3,145 - 3,545
Total	$7,740 - 8,140

Targeted capital expenditures incorporate the following levels of drilling activity:

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

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2013, excluding mark-to-market gains (losses) on risk management activities and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flow from operations ($ millions)	**Cash flow from operations** (per common share, basic)	**Net earnings** ($ millions)	**Net earnings** (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl [(1)]				
Excluding financial derivatives	$ 123	$ 0.11	$ 123	$ 0.11
Including financial derivatives	$ 123	$ 0.11	$ 123	$ 0.11
Natural gas – AECO C$0.10/Mcf [(1)]				
Excluding financial derivatives	$ 24	$ 0.02	$ 24	$ 0.02
Including financial derivatives	$ 9 – 16	$ 0.01	$ 9 – 16	$ 0.01
Volume changes				
Crude oil – 10,000 bbl/d	$ 144	$ 0.13	$ 102	$ 0.09
Natural gas – 10 MMcf/d	$ 5	$ –	$ –	$ –
Foreign currency rate change				
$0.01 change in US$ [(1)]				
Including financial derivatives	$ 93 – 95	$ 0.09	$ 51 – 52	$ 0.05
Interest rate change – 1%	$ 13	$ 0.01	$ 13	$ 0.01

(1) For details of financial instruments in place, refer to note 18 to the Company's consolidated financial statements as at December 31, 2013.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2013	2012	2011
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	**345,489**	**331,453**	**365,529**	**332,231**	**343,699**	326,829	295,618
North America – Oil Sands Mining and Upgrading	**108,782**	**67,954**	**111,959**	**112,273**	**100,284**	86,077	40,434
North Sea	**18,774**	**18,901**	**15,522**	**20,155**	**18,334**	19,824	29,992
Offshore Africa	**16,112**	**18,055**	**16,172**	**13,379**	**15,923**	18,648	23,009
Total	**489,157**	**436,363**	**509,182**	**478,038**	**478,240**	451,378	389,053
Natural gas (MMcf/d)							
North America	**1,125**	**1,092**	**1,136**	**1,165**	**1,130**	1,198	1,231
North Sea	**1**	**4**	**4**	**7**	**4**	2	7
Offshore Africa	**24**	**26**	**23**	**23**	**24**	20	19
Total	**1,150**	**1,122**	**1,163**	**1,195**	**1,158**	1,220	1,257
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	**532,971**	**513,424**	**554,756**	**526,518**	**531,961**	526,460	500,778
North America – Oil Sands Mining and Upgrading	**108,782**	**67,954**	**111,959**	**112,273**	**100,284**	86,077	40,434
North Sea	**19,016**	**19,578**	**16,254**	**21,273**	**19,029**	20,151	31,082
Offshore Africa	**20,075**	**22,359**	**19,969**	**17,178**	**19,888**	21,977	26,232
Total	**680,844**	**623,315**	**702,938**	**677,242**	**671,162**	654,665	598,526

PER UNIT RESULTS – EXPLORATION AND PRODUCTION

	Q1	Q2	Q3	Q4	2013	2012	2011
Crude oil and NGLs ($/bbl) [1]							
Sales price [2] [3]	**$ 60.87**	**$ 75.10**	**$ 89.24**	**$ 69.38**	**$ 73.81**	$ 72.44	$ 79.16
Transportation	**2.37**	**2.32**	**2.38**	**1.84**	**2.22**	2.20	1.70
Realized sales price, net of transportation	**58.50**	**72.78**	**86.86**	**67.54**	**71.59**	70.24	77.46
Royalties	**8.76**	**11.60**	**15.20**	**8.82**	**11.13**	10.67	12.30
Production expense	**17.56**	**16.51**	**15.90**	**18.59**	**17.14**	16.11	15.75
Netback	**$ 32.18**	**$ 44.67**	**$ 55.76**	**$ 40.13**	**$ 43.32**	$ 43.46	$ 49.41
Natural gas ($/Mcf) [1]							
Sales price [2] [3]	**$ 3.51**	**$ 4.05**	**$ 3.15**	**$ 3.62**	**$ 3.58**	$ 2.70	$ 3.99
Transportation	**0.29**	**0.29**	**0.27**	**0.28**	**0.28**	0.26	0.26
Realized sales price, net of transportation	**3.22**	**3.76**	**2.88**	**3.34**	**3.30**	2.44	3.73
Royalties	**0.12**	**0.28**	**0.10**	**0.21**	**0.18**	0.09	0.18
Production expense	**1.53**	**1.41**	**1.38**	**1.37**	**1.42**	1.31	1.15
Netback	**$ 1.57**	**$ 2.07**	**$ 1.40**	**$ 1.76**	**$ 1.70**	$ 1.04	$ 2.40
Barrels of oil equivalent ($/BOE) [1]							
Sales price [2] [3]	**$ 47.90**	**$ 58.49**	**$ 67.09**	**$ 53.30**	**$ 56.46**	$ 52.85	$ 58.81
Transportation	**2.21**	**2.18**	**2.18**	**1.83**	**2.10**	2.04	1.65
Realized sales price, net of transportation	**45.69**	**56.31**	**64.91**	**51.47**	**54.36**	50.81	57.16
Royalties	**6.05**	**8.29**	**10.35**	**6.23**	**7.74**	7.07	8.12
Production expense	**14.74**	**13.81**	**13.36**	**15.04**	**14.24**	13.14	12.42
Netback	**$ 24.90**	**$ 34.21**	**$ 41.20**	**$ 30.20**	**$ 32.38**	$ 30.60	$ 36.62

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING

	Q1	Q2	Q3	Q4	2013	2012	2011
Crude oil and NGLs ($/bbl) [1]							
SCO sales price [2]	**$ 96.19**	**$ 99.63**	**$ 114.19**	**$ 92.05**	**$ 100.75**	$ 90.74	$ 101.48
Bitumen royalties [3]	**3.81**	**4.41**	**6.82**	**5.06**	**5.11**	4.34	3.99
Transportation	**1.58**	**1.72**	**1.52**	**1.51**	**1.57**	1.83	1.74
Adjusted cash production costs	**39.93**	**44.94**	**39.90**	**39.05**	**40.57**	42.83	36.64
Netback	**$ 50.87**	**$ 48.56**	**$ 65.95**	**$ 46.43**	**$ 53.50**	$ 41.74	$ 59.11

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period of turnaround/suspension of production.
(2) Comparative figures have been adjusted to reflect realized product prices before transportation costs.
(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2013	2012
TSX – C$						
Trading volume (thousands)	**179,043**	**183,999**	**177,215**	**142,746**	**683,003**	729,700
Share Price ($/share)						
High	**$ 33.91**	**$ 32.86**	**$ 34.64**	**$ 36.04**	**$ 36.04**	$ 41.12
Low	**$ 28.66**	**$ 28.44**	**$ 29.72**	**$ 31.73**	**$ 28.44**	$ 25.58
Close	**$ 32.57**	**$ 29.65**	**$ 32.37**	**$ 35.94**	**$ 35.94**	$ 28.64
Market capitalization as at December 31 ($ millions)					**$ 39,078**	$ 31,277
Shares outstanding (thousands)					**1,087,322**	1,092,072
NYSE – US$						
Trading volume (thousands)	**191,606**	**175,318**	**128,718**	**149,761**	**645,403**	844,647
Share Price ($/share)						
High	**$ 33.21**	**$ 32.43**	**$ 33.64**	**$ 33.92**	**$ 33.92**	$ 41.38
Low	**$ 29.06**	**$ 26.98**	**$ 27.80**	**$ 30.42**	**$ 26.98**	$ 25.01
Close	**$ 32.13**	**$ 28.26**	**$ 31.44**	**$ 33.84**	**$ 33.84**	$ 28.87
Market capitalization as at December 31 ($ millions)					**$ 36,795**	$ 31,528
Shares outstanding (thousands)					**1,087,322**	1,092,072

ADDITIONAL DISCLOSURE

Certifications

The required disclosure is included in Exhibits 2, 3, 4 and 5 to this Annual Report on Form 40-F

Disclosure Controls and Procedures

As of the end of the registrant's fiscal year ended December 31, 2013, an evaluation of the effectiveness of Canadian Natural's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), was carried out by Canadian Natural's management with the participation of Canadian Natural's principal executive officer and principal financial officer. Based upon the evaluation, Canadian Natural's principal executive officer and principal financial officer have concluded that as of the end of the fiscal year, Canadian Natural's disclosure controls and procedures are effective to ensure that information required to be disclosed by Canadian Natural in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and (ii) accumulated and communicated to Canadian Natural's management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

It should be noted that while Canadian Natural's principal executive officer and principal financial officer believe that Canadian Natural's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect Canadian Natural's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Management's Annual Report on Internal Control Over Financial Reporting

The required disclosure is included in the "Management's Assessment of Internal Control Over Financial Reporting" that accompanies Canadian Natural's audited consolidated financial statements for the fiscal year ended December 31, 2013, filed as part of this Annual Report on Form 40-F.

Attestation Report of the Registered Public Accounting Firm

The required disclosure is included in the "Independent Auditor's Report" that accompanies Canadian Natural's audited consolidated financial statements for the fiscal year ended December 31, 2013, filed as part of this Annual Report on Form 40-F.

Changes in Internal Control Over Financial Reporting

During the fiscal year ended December 31, 2013, there were no changes in Canadian Natural's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, Canadian Natural's internal control over financial reporting.

Notices Pursuant to Regulation BTR

None.

Audit Committee Financial Expert

The Board of Directors of Canadian Natural has determined that Ms. C.M. Best qualifies as an "audit committee financial expert" (as defined in paragraph 8(b) of General Instruction B to Form 40-F) serving on its Audit Committee. Ms. C.M. Best is, as are all members of the Audit Committee of the Board of Directors of Canadian Natural, "independent" as such term is defined in the rules of the New York Stock Exchange.

Code of Ethics

Canadian Natural has a long-standing Code of Integrity, Business Ethics and Conduct (the "Code of Ethics"), which covers such topics as employment standards, conflict of interest, the treatment of confidential information and trading in Canadian Natural's shares and is designed to ensure that Canadian Natural's business is consistently conducted in a legal and ethical manner. Each director and all employees, including each member of senior management and more specifically the principal executive officer, principal financial officer, principal accounting officer or controller and persons performing similar functions, are required to abide by the Code of Ethics. The Nominating and Corporate Governance Committee periodically reviews the Code of Ethics to ensure it addresses appropriate topics and complies with regulatory requirements and recommends any appropriate changes to the Board for approval.

Any waivers of or amendments to the Code of Ethics must be approved by the Board of Directors and will be appropriately disclosed. In the past fiscal year, there have not been any waivers, including implicit waivers, from any provisions of the Code of Ethics and there have been no substantive amendments.

The Code of Ethics is available through the System for Electronic Document and Analysis and Retrieval (SEDAR) at www.sedar.com. Canadian Natural hereby undertakes to provide to any person, without charge and upon request, a copy of its Code of Ethics. Requests for copies can also be made by contacting: Bruce E. McGrath, Corporate Secretary, Canadian Natural Resources Limited, 2500-855 2nd Street, S.W., Calgary, Alberta, Canada T2P 4J8.

Principal Accountant Fees and Services

PricewaterhouseCoopers LLP ("PwC") has been the auditor of Canadian Natural since Canadian Natural's inception. The aggregate amounts billed by PwC for each of the last two fiscal years for audit fees, audit-related fees, tax fees and all other fees, excluding expenses, are set forth below.

Audit Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural ended December 31, 2013 and December 31, 2012, for professional services rendered by PwC for the audit of its internal controls and annual consolidated financial statements in connection with statutory and regulatory filings or engagements for those fiscal years, unaudited reviews of the first, second and third quarters of its interim consolidated financial statements and audits of certain of Canadian Natural's subsidiary companies' annual financial statements were $3,032,000 for 2013 and were $2,723,000 for 2012.

Audit-Related Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ended December 31, 2013 and December 31, 2012, for audit-related services by PwC including pension assets and Crown Royalty Statements, were $212,000 for 2013 and were $183,000 for 2012. Canadian Natural's Audit Committee approved all of these audit-related services.

Tax Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ended December 31, 2013 and December 31, 2012, for professional services rendered by PwC for tax services related to expatriate personal tax compliance and other corporate tax return matters were $478,000 for 2013 and were $481,000 for 2012. Canadian Natural's Audit Committee approved all of these tax-related services.

All Other Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ended December 31, 2013 and December 31, 2012 for other services were $73,000 for 2013 and were $9,000 for 2012. The fees for other services paid in 2013 related to expatriate visa application assistance and to accessing resource materials through PwC's accounting literature library. Canadian Natural's Audit Committee approved all of the noted services.

Audit Committee Pre-Approval Policies and Procedures

The Audit Committee's duties and responsibilities include the review and approval of fees to be paid to the independent auditors, scope and timing of the audit and other related services rendered by the independent auditors. The Audit Committee also reviews and approves the independent auditor's annual audit plan, including scope, staffing, locations and reliance upon management and internal audit department prior to the commencement of the audit and reviews and approves proposed non-audit services to be provided by the independent auditors, except those non-audit services prohibited by legislation. Canadian Natural did not rely on the de minimis exemption provided by paragraph (c)(7)(i)(c) of Rule 2.01 of Regulation S-X in 2013.

Off Balance Sheet Arrangements

The Company does not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Tabular Disclosure of Contractual Obligations

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at December 31, 2013:

($ millions)	2014	2015	2016	2017	2018	Thereafter
Product transportation and pipeline	$ 298	$ 293	$ 225	$ 208	$ 176	$ 1,324
Offshore equipment operating leases and offshore drilling	$ 147	$ 238	$ 81	$ 61	$ 54	$ 17
Long-term debt (1)	$ 1,436	$ 400	$ 931	$ 1,750	$ 426	$ 4,776
Interest and other financing expense (2)	$ 441	$ 405	$ 387	$ 323	$ 270	$ 3,803
Office leases	$ 35	$ 41	$ 42	$ 45	$ 47	$ 321
Other	$ 309	$ 172	$ 71	$ 1	$ 1	$ 1

(1) Long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs.

(2) Interest and other financing expense amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at December 31, 2013.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases of Horizon. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

Identification of the Audit Committee

Canadian Natural has a separately designated standing audit committee established in accordance with section 3(a)(58)(A) of the Exchange Act. The members of the Audit Committee are Ms. C.M. Best, who chairs the Audit Committee and Messrs. T. W. Faithfull, G. A. Filmon, G. D. Giffin, D. A. Tuer.

Mine Safety Disclosure

Not Applicable

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UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

Undertaking

Canadian Natural undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

Consent to Service of Process

Canadian Natural has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

Any change to the name or address of the agent for service of process of Canadian Natural shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the registrant.

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SIGNATURES

Pursuant to the requirements of the Exchange Act, Canadian Natural certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report to be signed on its behalf by the undersigned, thereto duly authorized.

Dated this 24th day of March, 2014.

CANADIAN NATURAL RESOURCES LIMITED

By: SIGNED “STEVE W. LAUT”
Name: Steve W. Laut
Title: President

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Documents filed as part of this report:

EXHIBIT INDEX

Exhibit No.	Description
1.	Supplementary Oil & Gas Information for the fiscal year ended December 31, 2013.
2.	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
3.	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
4.	Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
5.	Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
6.	Consent of PricewaterhouseCoopers LLP, independent chartered accountants.
7.	Consent of Sproule Associates Limited, independent petroleum engineering consultants.
8.	Consent of Sproule International Limited, independent petroleum engineering consultants.
9.	Consent of GLJ Petroleum Consultants Ltd., independent petroleum engineering consultants.

EXHIBIT 1

Supplementary Oil & Gas Information for the Fiscal Year Ended December 31, 2013

SUPPLEMENTARY OIL & GAS INFORMATION (unaudited)

This supplementary crude oil and natural gas information is provided in accordance with the United States Financial Accounting Standards Board ("FASB") Topic 932 – "Extractive Activities – Oil and Gas" and where applicable, financial information is prepared in accordance with International Financial Reporting Standards ("IFRS").

For the years ended December 31, 2013, 2012, 2011, and 2010, the Company filed its reserves information under National Instrument 51-101 – "Standards of Disclosure of Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada.

There are significant differences to the type of volumes disclosed and the basis from which the volumes are economically determined under the United States Securities and Exchange Commission ("SEC") requirements and NI 51-101. The SEC requires disclosure of net reserves, after royalties, using 12-month average prices and current costs; whereas NI 51-101 requires gross reserves, before royalties, using forecast pricing and costs. Therefore the difference between the reported numbers under the two disclosure standards can be material.

For the purposes of determining proved crude oil and natural gas reserves for SEC requirements as at December 31, 2013, 2012, 2011, and 2010 the Company used the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The Company has used the following 12-month average benchmark prices to determine its 2013 reserves for SEC requirements.

Crude Oil and NGLs				**Natural Gas**			
WTI Cushing Oklahoma (US$/bbl)	WCS (C$/bbl)	Edmonton Par (C$/bbl)	North Sea Brent (US$/bbl)	Edmonton C5+ (C$/bbl)	Henry Hub Louisiana (US$/MMbtu)	AECO (C$/MMbtu)	BC Westcoast Station 2 (C$/MMbtu)
96.94	74.22	92.73	108.22	105.65	3.68	3.16	3.08

A foreign exchange rate of US$1.00/C$1.0291 was used in the 2013 evaluation, determined on the same basis as the 12-month average price.

NET PROVED CRUDE OIL AND NATURAL GAS RESERVES

The Company retains Independent Qualified Reserves Evaluators to evaluate the Company's proved crude oil, bitumen, synthetic crude oil ("SCO"), natural gas liquids ("NGLs") and natural gas reserves.

- For the years ended December 31, 2013, 2012, 2011, and 2010, the reports by GLJ Petroleum Consultants Ltd. covered 100% of the Company's SCO reserves. With the inclusion of non-traditional resources within the definition of "oil and gas producing activities" in the SEC's modernization of oil and gas reporting rules ("Final Rule"), effective January 1, 2010 these reserves volumes are included within the Company's crude oil and natural gas reserves totals.

- For the years ended December 31, 2013, 2012, 2011, and 2010, the reports by Sproule Associates Limited and Sproule International Limited covered 100% of the Company's bitumen, crude oil and NGLs, and natural gas reserves.

Proved crude oil and natural gas reserves, as defined within the SEC's Regulation S-X under the Final Rule, are the estimated quantities of oil and gas that geoscience and engineering data demonstrate with reasonable certainty to be economically producible, from a given date forward, from known reservoirs under existing economic conditions, operating methods and government regulations. Proved developed reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of drilling a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Estimates of crude oil and natural gas reserves are subject to uncertainty and will change as additional information regarding producing fields and technology becomes available and as future economic and operating conditions change.

The following tables summarize the Company's proved and proved developed crude oil and natural gas reserves, net of royalties, as at December 31, 2013, 2012, 2011, and 2010:

	North America						
Crude Oil and NGLs (MMbbl)	**Synthetic Crude Oil**	**Bitumen[1]**	**Crude Oil & NGLs**	**North America Total**	**North Sea**	**Offshore Africa**	**Total**
Net Proved Reserves							
Reserves, December 31, 2010	1,663	878	328	2,869	257	102	3,228
Extensions and discoveries	–	78	28	106	–	–	106
Improved recovery	–	10	8	18	–	2	20
Purchases of reserves in place	–	–	6	6	–	–	6
Sales of reserves in place	–	–	–	–	–	–	–
Production	(14)	(60)	(28)	(102)	(11)	(8)	(121)
Economic revisions due to prices	18	(32)	1	(13)	26	–	13
Revisions of prior estimates	169	(5)	23	187	(28)	(8)	151
Reserves, December 31, 2011	1,836	869	366	3,071	244	88	3,403
Extensions and discoveries	–	90	5	95	–	–	95
Improved recovery	–	25	9	34	–	1	35
Purchases of reserves in place	–	–	2	2	–	–	2
Sales of reserves in place	–	–	–	–	–	–	–
Production	(30)	(70)	(31)	(131)	(7)	(5)	(143)
Economic revisions due to prices	34	6	(20)	20	4	–	24
Revisions of prior estimates	134	79	39	252	(6)	1	247
Reserves, December 31, 2012	1,974	999	370	3,343	235	85	3,663
Extensions and discoveries	**–**	**76**	**13**	**89**	**–**	**–**	**89**
Improved recovery	**–**	**9**	**7**	**16**	**–**	**–**	**16**
Purchases of reserves in place	**–**	**–**	**8**	**8**	**6**	**–**	**14**
Sales of reserves in place	**–**	**–**	**–**	**–**	**–**	**–**	–
Production	**(35)**	**(71)**	**(33)**	**(139)**	**(7)**	**(5)**	**(151)**
Economic revisions due to prices	**(10)**	**(1)**	**4**	**(7)**	**–**	**(2)**	**(9)**
Revisions of prior estimates	**(4)**	**56**	**11**	**63**	**(2)**	**2**	**63**
Reserves, December 31, 2013	**1,925**	**1,068**	**380**	**3,373**	**232**	**80**	**3,685**
Net proved developed reserves							
December 31, 2010	1,546	262	240	2,048	94	83	2,225
December 31, 2011	1,588	269	269	2,126	78	61	2,265
December 31, 2012	1,612	348	295	2,255	66	55	2,376
December 31, 2013	**1,621**	**431**	**298**	**2,350**	**59**	**30**	**2,439**

(1) Bitumen as defined by the SEC under the Final Rule, "is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis." Under this definition, all the Company's thermal and primary heavy crude oil reserves have been classified as bitumen.

Natural Gas (Bcf)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Net Proved Reserves				
Reserves, December 31, 2010	3,421	78	76	3,575
Extensions and discoveries	154	–	–	154
Improved recovery	48	–	–	48
Purchases of reserves in place	375	–	–	375
Sales of reserves in place	(1)	–	–	(1)
Production	(433)	(2)	(6)	(441)
Economic revisions due to prices	(104)	3	–	(101)
Revisions of prior estimates	39	18	(16)	41
Reserves, December 31, 2011	3,499	97	54	3,650
Extensions and discoveries	50	–	–	50
Improved recovery	11	–	–	11
Purchases of reserves in place	34	–	–	34
Sales of reserves in place	(1)	–	–	(1)
Production	(429)	(1)	(6)	(436)
Economic revisions due to prices	(596)	1	–	(595)
Revisions of prior estimates	79	(14)	–	65
Reserves, December 31, 2012	2,647	83	48	2,778
Extensions and discoveries	**126**	**–**	**–**	**126**
Improved recovery	**62**	**–**	**–**	**62**
Purchases of reserves in place	**99**	**14**	**–**	**113**
Sales of reserves in place	**(1)**	**–**	**–**	**(1)**
Production	**(394)**	**(1)**	**(8)**	**(403)**
Economic revisions due to prices	**489**	**–**	**(2)**	**487**
Revisions of prior estimates	**206**	**(4)**	**(1)**	**201**
Reserves, December 31, 2013	**3,234**	**92**	**37**	**3,363**
Net proved developed reserves				
December 31, 2010	2,557	49	72	2,678
December 31, 2011	2,637	60	47	2,744
December 31, 2012	2,060	58	39	2,157
December 31, 2013	**2,342**	**72**	**27**	**2,441**

CAPITALIZED COSTS RELATED TO CRUDE OIL AND NATURAL GAS ACTIVITIES

	2013			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Proved properties	**$ 73,176**	**$ 5,200**	**$ 3,356**	**$ 81,732**
Unproved properties	**2,570**	**–**	**39**	**2,609**
	75,746	**5,200**	**3,395**	**84,341**
Less: accumulated depletion and depreciation	**(29,729)**	**(3,467)**	**(2,551)**	**(35,747)**
Net capitalized costs	**$ 46,017**	**$ 1,733**	**$ 844**	**$ 48,594**

	2012			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	$ 67,287	$ 4,574	$ 3,045	$ 74,906
Unproved properties	2,564	–	47	2,611
	69,851	4,574	3,092	77,517
Less: accumulated depletion and depreciation	(26,193)	(2,709)	(2,273)	(31,175)
Net capitalized costs	$ 43,658	$ 1,865	$ 819	$ 43,836

	2011			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	$ 61,331	$ 4,147	$ 3,044	$ 68,522
Unproved properties	2,442	–	33	2,475
	63,773	4,147	3,077	70,997
Less: accumulated depletion and depreciation	(22,497)	(2,512)	(2,152)	(27,161)
Net capitalized costs	$ 41,276	$ 1,635	$ 925	$ 43,836

COSTS INCURRED IN CRUDE OIL AND NATURAL GAS ACTIVITIES

(millions of Canadian dollars)	2013 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
Costs incurred	$ 6,492	$ 299	$ 126	$ 6,917

(millions of Canadian dollars)	2012 North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 144	$ –	$ –	$ 144
Unproved	44	–	3	47
Exploration	251	–	11	262
Development	5,773	556	75	6,404
Costs incurred	$ 6,212	$ 556	$ 89	$ 6,857

(millions of Canadian dollars)	2011 North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 1,012	$ –	$ –	$ 1,012
Unproved	59	–	–	59
Exploration	250	1	2	253
Development	5,559	235	76	5,870
Costs incurred	$ 6,880	$ 236	$ 78	$ 7,194

RESULTS OF OPERATIONS FROM CRUDE OIL AND NATURAL GAS PRODUCING ACTIVITIES

The Company's results of operations from crude oil and natural gas producing activities for the years ended December 31, 2013, 2012 and 2011 are summarized in the following tables:

	2013			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Crude oil and natural gas revenue, net of royalties and blending costs	**$ 12,274**	**$ 726**	**$ 687**	**$ 13,687**
Production	**(3,918)**	**(436)**	**(191)**	**(4,545)**
Transportation	**(483)**	**(6)**	**(1)**	**(490)**
Depletion, depreciation and amortization	**(4,150)**	**(552)**	**(134)**	**(4,836)**
Asset retirement obligation accretion	**(126)**	**(35)**	**(10)**	**(171)**
Petroleum revenue tax	**–**	**188**	**–**	**188**
Income tax	**(903)**	**71**	**(88)**	**(920)**
Results of operations	**$ 2,694**	**$ (44)**	**$ 263**	**$ 2,913**

	2012			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 10,609	$ 837	$ 574	$ 12,020
Production	(3,669)	(402)	(163)	(4,234)
Transportation	(479)	(10)	(1)	(490)
Depletion, depreciation and amortization	(3,860)	(296)	(165)	(4,321)
Asset retirement obligation accretion	(117)	(27)	(7)	(151)
Petroleum revenue tax	–	(14)	–	(14)
Income tax	(623)	(55)	(55)	(733)
Results of operations	$ 1,861	$ 33	$ 183	$ 2,077

	2011			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 9,600	$ 1,206	$ 828	$ 11,634
Production	(3,060)	(412)	(186)	(3,658)
Transportation	(374)	(13)	(1)	(388)
Depletion, depreciation and amortization	(3,488)	(248)	(242)	(3,978)
Asset retirement obligation accretion	(90)	(33)	(7)	(130)
Petroleum revenue tax	–	(130)	–	(130)
Income tax	(688)	(218)	(89)	(995)
Results of operations	$ 1,900	$ 152	$ 303	$ 2,355

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS FROM PROVED CRUDE OIL AND NATURAL GAS RESERVES AND CHANGES THEREIN

The following standardized measure of discounted future net cash flows from proved crude oil and natural gas reserves has been computed using the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, costs as at the balance sheet date and year-end statutory income tax rates. A discount factor of 10% has been applied in determining the standardized measure of discounted future net cash flows. The Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair value of the crude oil and natural gas properties. Actual net cash flows will differ from the presented estimated future net cash flows due to several factors including:

- Future production will include production not only from proved properties, but may also include production from probable and possible reserves;
- Future production of crude oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future prices and costs rather than 12-month average prices and costs as at the balance sheet date will apply;
- Economic factors such as interest rates, income tax rates, regulatory and fiscal environments and operating conditions will change;
- Future estimated income taxes do not take into account the effects of future exploration and evaluation expenditures; and
- Future development and asset retirement obligations will differ from those estimated.

Future net revenues, development, production and asset retirement obligation costs have been based upon the estimates referred to above. The following tables summarize the Company's future net cash flows relating to proved crude oil and natural gas reserves based on the standardized measure as prescribed in FASB Topic 932 – "Extractive Activities – Oil and Gas":

	2013			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Future cash inflows	**$ 290,892**	**$ 26,378**	**$ 9,146**	**$ 326,416**
Future production costs	**(116,984)**	**(9,921)**	**(2,560)**	**(129,465)**
Future development costs and asset retirement obligations	**(51,749)**	**(7,602)**	**(1,840)**	**(61,191)**
Future income taxes	**(20,384)**	**(6,586)**	**(1,154)**	**(28,124)**
Future net cash flows	**101,775**	**2,269**	**3,592**	**107,636**
10% annual discount for timing of future cash flows	**(65,063)**	**(976)**	**(1,755)**	**(67,794)**
Standardized measure of future net cash flows	**$ 36,712**	**$ 1,293**	**$ 1,837**	**$ 39,842**

	2012			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Future cash inflows	$ 273,167	$ 26,922	$ 7,985	$ 308,074
Future production costs	(114,825)	(9,369)	(2,428)	(126,622)
Future development costs and asset retirement obligations	(49,226)	(7,032)	(1,640)	(57,898)
Future income taxes	(16,688)	(7,662)	(949)	(25,299)
Future net cash flows	92,428	2,859	2,968	98,255
10% annual discount for timing of future cash flows	(61,878)	(1,330)	(1,313)	(64,521)
Standardized measure of future net cash flows	$ 30,550	$ 1,529	$ 1,655	$ 33,734

	2011			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Future cash inflows	$ 280,809	$ 26,887	$ 8,257	$ 315,953
Future production costs	(109,586)	(8,908)	(2,058)	(120,552)
Future development costs and asset retirement obligations	(37,486)	(6,821)	(1,669)	(45,976)
Future income taxes	(23,100)	(8,095)	(1,070)	(32,265)
Future net cash flows	110,637	3,063	3,460	117,160
10% annual discount for timing of future cash flows	(75,438)	(1,376)	(1,623)	(78,437)
Standardized measure of future net cash flows	$ 35,199	$ 1,687	$ 1,837	$ 38,723

The principal sources of change in the standardized measure of discounted future net cash flows are summarized in the following table:

(millions of Canadian dollars)	**2013**	2012	2011
Sales of crude oil and natural gas produced, net of production costs	**$ (8,525)**	$ (7,895)	$ (7,727)
Net changes in sales prices and production costs	**6,992**	(7,994)	15,802
Extensions, discoveries and improved recovery	**2,304**	1,834	1,328
Changes in estimated future development costs	**(1,536)**	(3,492)	(2,022)
Purchases of proved reserves in place	**638**	83	803
Sales of proved reserves in place	**(1)**	(1)	–
Revisions of previous reserve estimates	**622**	4,266	4,154
Accretion of discount	**4,388**	5,110	3,648
Changes in production timing and other	**2,341**	946	(1,141)
Net change in income taxes	**(1,115)**	2,154	(3,009)
Net change	**6,108**	(4,989)	11,836
Balance – beginning of year	**33,734**	38,723	26,887
Balance – end of year	**$ 39,842**	$ 33,734	$ 38,723

EXHIBIT 2

Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a)
of the Securities Exchange Act of 1934

CERTIFICATION

I, Steve W. Laut, certify that:

1. I have reviewed this annual report on Form 40-F of Canadian Natural Resources Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13(a)-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated this 24th day of March, 2014.

SIGNED " STEVE W. LAUT"
Steve W. Laut
President (Principal Executive Officer),
Canadian Natural Resources Limited

EXHIBIT 3

Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a)
of the Securities Exchange Act of 1934

CERTIFICATION

I, Corey B. Bieber, certify that:

1. I have reviewed this annual report on Form 40-F of Canadian Natural Resources Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13(a)-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusion about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated this 24th day of March, 2014.

SIGNED "COREY B. BIEBER"
Corey B. Bieber
Chief Financial Officer and Senior Vice-President, Finance (Principal Financial Officer),
Canadian Natural Resources Limited

EXHIBIT 4

Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350)

In connection with the Annual Report of Canadian Natural Resources Limited (the "Company") on Form 40-F for the fiscal year ending December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Steve W. Laut, certify pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

DATED this 24th day of March, 2014.

SIGNED "STEVE W. LAUT"
Steve W. Laut
President (Principal Executive Officer),
Canadian Natural Resources Limited

EXHIBIT 5

Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350)

In connection with the Annual Report of Canadian Natural Resources Limited (the "Company") on Form 40-F for the fiscal year ending December 31, 2013as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Corey B. Bieber, certify pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

DATED this 24th day of March, 2014.

SIGNED "COREY B. BIEBER"
Corey B. Bieber
Chief Financial Officer and Senior Vice-President, Finance (Principal Financial Officer),
Canadian Natural Resources Limited

EXHIBIT 6

March 24, 2014

Consent of Independent Auditor

We hereby consent to the inclusion in this Annual Report on Form 40-F for the year ended December 31, 2013 of Canadian Natural Resources Limited of our report dated March 5, 2014, relating to the consolidated financial statements, and the effectiveness of internal control over financial reporting, which appears in this Annual Report.

We also consent to the incorporation by reference in the Registration Statement on Form F-10 (File No. 333- 191876) of Canadian Natural Resources Limited of our report dated March 5, 2014 referred to above.

SIGNED “PRICEWATERHOUSECOOPERS LLP”

Chartered Accountants

EXHIBIT 7



H.J. Helwerda*, B.Sc., P.Eng., FEC, *President & COO*
D.J. Carsted*, CD, B.Sc., P.Geol., *Executive VP & CTO*
G.D. Robinson*, B.Sc., P.Eng., *VP, International*
C.P. Six*, B.Sc., P.Eng., *VP, Unconventional*
A.A. Szabo*, B.Sc., P.Eng., *Manager, Engineering*
S.W. Pennell, B.S., P.Eng., *Manager, Engineering, International*
B.F. Jose, M.Sc., P.Geoph., *VP, Geoscience, International*
N.T. Stewart, B.A.Sc., P.Eng., *VP, Engineering, Canada*
K.P. McDonald, B.Comm, CA, *CFO*
M.R. Van de Veen, QC, J.D., M.B.A., L.L.M., *General Counsel, Corporate Secretary*

**Directors*

Ref.: 1808

March 24, 2014

Canadian Natural Resources Limited
2500, 855 Second Street SW
Calgary, AB T2P 4J8

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

We consent to the use of our report with respect to the reserves data of Canadian Natural Resources Limited included and incorporated by reference in its

(i) Annual Report on Form 40-F for the year ended December 31, 2013; and,

(ii) Registration Statement on Form F-10 (File No. 333-191876), filed with the Securities and Exchange Commission.

Sincerely,

SPROULE ASSOCIATES LIMITED

Original Signed by Nora T. Stewart, P.Eng.

Nora T. Stewart, P.Eng.
Vice-President, Canada and Partner

EXHIBIT 8



H.J. Helwerda*, B.Sc., P.Eng., FEC, *President & COO*
D.J. Carsted*, CD, B.Sc., P.Geol., *Executive VP & CTO*
G.D. Robinson*, B.Sc., P.Eng., *VP, International*
C.P. Six*, B.Sc., P.Eng., *VP, Unconventional*
A.A. Szabo*, B.Sc., P.Eng., *Manager, Engineering*
S.W. Pennell, B.S., P.Eng., *Manager, Engineering, International*
B.F. Jose, M.Sc., P.Geoph., *VP, Geoscience, International*
N.T. Stewart, B.A.Sc., P.Eng., *VP, Engineering, Canada*
K.P. McDonald, B.Comm, CA, *CFO*
M.R. Van de Veen, QC, J.D., M.B.A., L.L.M., *General Counsel, Corporate Secretary*

**Directors*

Ref.: 1808

March 24, 2014

Canadian Natural Resources Limited
2500, 855 – 2nd Street SW
CALGARY AB T2P 4J8

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

We consent to the use of our report with respect to the reserves data of Canadian Natural Resources Limited included and incorporated by reference in its

(i) Annual Report on Form 40-F for the year ended December 31, 2013; and,

(ii) Registration Statement on Form F-10 (File No. 333-191876), filed with the Securities and Exchange Commission.

Sincerely,

SPROULE INTERNATIONAL LIMITED

Original Signed by Scott W. Pennell, P.Eng.

Scott W. Pennell, P.Eng.
Manager, Engineering and Director

EXHIBIT 9



Principal Officers:
Keith M. Braaten, P. Eng.
President & CEO
Jodi L. Anhorn, P. Eng.
Executive Vice President & COO

Officers / Vice Presidents:
Terry L. Aarsby, P. Eng.
Caralyn P. Bennett, P. Eng.
Leonard L. Herchen, P. Eng.
Myron J. Hladyshevsky, P. Eng.
Todd J. Ikeda, P. Eng.
Bryan M. Joa, P. Eng.
Mark Jobin, P. Geol.
John E. Keith, P. Eng.
John H. Stilling, P. Eng.
Douglas R. Sutton, P. Eng.
James H. Willmon, P. Eng.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

Canadian Natural Resources Limited
2500, 855 – 2nd Street SW
Calgary, Alberta T2P 4J8

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

We consent to the use of our report with respect to the reserves data of Canadian Natural Resources Limited included and incorporated by reference in its

(i) Annual Report on Form 40-F for the year ended December 31, 2013; and,

(ii) Registration Statement on Form F-10 (File No. 333-191876), filed with the Securities and Exchange Commission.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

"Originally Signed By"

Caralyn P. Bennett, P. Eng.
Vice-President

Calgary, Alberta
March 24, 2014