CANADIAN NATURAL RESOURCES LTD
Form 40-F
March 22, 2018

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, 2017	Commission File Number: 001-12138

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

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

1311
(Primary Standard Industrial Classification Code Numbers)

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

2100, 855-2nd Street S.W., Calgary, Alberta, Canada, T2P 4J8
Telephone: (403) 517-7345
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System, 111-Eighth Avenue, New York, New York 10011
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code)
of agent for service in the United States)
Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of Each Class:	Name of each exchange on which registered:
Common Shares, no par value	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act:
Title of Each Class: None
Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: None
For annual reports, indicate by check mark the information filed with this Form:
[X] Annual information form [X] Audited annual financial statements

Indicate the 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.
1,222,769,000 Common Shares outstanding as of December 31, 2017

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the Registrant in connection with such Rule.
Yes [ ] No [X]
Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.
Yes [X] No [ ]
Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.
Emerging growth company [ ]

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. [ ]
† The term new or revised financial accounting standard refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.
This Annual Report on Form 40-F shall be incorporated by reference into, or as an exhibit to, as applicable, the Registrant's Registration Statements on Form F-10 (File Nos. 333-219366 and 333-219367) under the Securities Act of 1933 as amended.
All dollar amounts in this Annual Report on Form 40-F are expressed in Canadian dollars. On March 20, 2018 the reported Bank of Canada exchange rate for one Canadian dollar was US$0.7647. On March 20, 2018 the reported Bank of Canada exchange rate for one U. S. dollar was C$1.3077.
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, 2017.

B. Audited Annual Financial Statements

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2017 and 2016, including the report of independent registered public accounting firm with respect thereto.

C. Management's Discussion and Analysis

Canadian Natural's Management's Discussion and Analysis for the year ended December 31, 2017.

The following document is filed as an exhibit to this Annual Report on Form 40-F and is incorporated by reference herein:

A. Supplementary Oil & Gas Information (Unaudited)

For Canadian Natural's Supplementary Oil & Gas Information (Unaudited) for the year ended December 31, 2017, see Exhibit 99.1 to this Annual Report on Form 40-F.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2017

March 21, 2018

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DEFINITIONS AND ABBREVIATIONS

AOSP	Athabasca Oil Sands Project
API	Specific gravity measured in degrees on the American Petroleum Institute scale
ARO	Asset retirement obligations
bbl	barrel
bbl/d	barrels per day
Bcf	billion cubic feet
bitumen	Naturally occurring solid or semi-solid hydrocarbon, consisting mainly of heavier hydrocarbons that are too heavy or thick to flow at reservoir conditions, and recoverable at economic rates using thermal in-situ recovery methods
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
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalents
crude oil, natural gas and NGLs	The Company's light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, synthetic crude oil, bitumen (thermal oil), natural gas and natural gas liquids
CSS	Cyclic Steam Stimulation
development well	Well drilled inside the established limits of an oil or gas reservoir or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive
dry well	Well that proves to be incapable of producing either crude oil or natural gas in sufficient quantities to justify completion
EOR	Enhanced Oil Recovery
exploratory well	Well that is not a development well, a service well, or a stratigraphic test well
extension well	Well that is drilled to test if a known reservoir extends beyond what had previously been believed to be the outer reservoir perimeter
fee title interest	Absolute ownership of legal title to mineral lands, subject to conditional interests that may have been granted from the title, such as petroleum and natural gas leases
FPSO	Floating Production, Storage and Offloading vessel
GHG	Greenhouse gas
gross acres	Total number of acres in which the Company has a working interest or fee title interest
gross wells	Total number of wells in which the Company has a working interest
Horizon	Horizon Oil Sands
IFRS	International Financial Reporting Standards
Mbbl	thousand barrels
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MD&A	Management's Discussion and Analysis
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MM$	million Canadian dollars

NGLs	Natural gas liquids
net acres	Gross acres multiplied by the percentage working interest or fee title interest therein owned
net asset value	Calculated as net present value, discounted at 10%, of the future net revenue (before income tax and excluding the ARO for development existing as at December 31, 2017) of the Company's total proved plus probable crude oil, natural gas and NGLs reserves prepared using forecast prices and costs, plus the estimated market value of core unproved property, less net debt. Net debt is long term debt plus/minus the working capital deficit/surplus. Future development costs and abandonment and reclamation costs attributable to future development activity have been applied against the future net revenue

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
Quest	Quest Carbon Capture and Storage ("CCS") project
SAGD	Steam-Assisted Gravity Drainage
SCO	Synthetic crude oil
SEC	United States Securities and Exchange Commission
service well	Well drilled or completed for the purpose of supporting production in an existing field and drilled for the specific purposes of gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion
stratigraphic test well	Drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition and ordinarily drilled without the intention of being completed for hydrocarbon production
TSX	Toronto Stock Exchange
UK	United Kingdom
unproved property	Property or part of a property to which no reserves have been specifically attributed
US	United States
working interest	Interest held by the Company in a crude oil or natural gas property, which interest normally bears its proportionate share of the costs of exploration, development, and operation as well as any royalties or other production burdens
WTI	West Texas Intermediate reference location at Cushing, Oklahoma

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this Annual Information Form ("AIF") 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", "con "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlo "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 AIF constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Oil Sands Mining and Upgrading 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, and 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 and reference to the 2018 activity provided 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 NGLs reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of future production may vary significantly from reserves 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 its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves 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 national, 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 AIF, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data are presented on a "before royalties" or "gross" basis unless otherwise stated. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

The comparative Consolidated Financial Statements and the Company's MD&A for the most recently completed fiscal year ended December 31, 2017, herein incorporated by reference, and certain information included in this AIF, have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board.

For the year ended December 31, 2017, the Company retained Independent Qualified Reserves Evaluators ("IQRE"), Sproule Associates Limited and Sproule International Limited (together as "Sproule") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved and proved plus probable reserves with an effective date of December 31, 2017 and a preparation date of February 7, 2018. Sproule evaluated and reviewed 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 Horizon SCO reserves and reviewed AOSP SCO reserves. The evaluations and reviews were 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 annual report on Form 40-F filed with the SEC and in the "Supplementary Oil and Gas Information" section of the Company's Annual Report on pages 96 to 105 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 (loss) from operations, funds flow from operations (previously referred to as 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 (loss) and cash flows from operating activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings (loss) from operations and funds flow from operations are reconciled to net earnings (loss), as determined in accordance with IFRS in the "Net Earnings (Loss) and Funds Flow from Operations" section of the Company's MD&A for the year ended December 31, 2017 which is incorporated by reference into this document. The non-GAAP measure funds flow from operations is also reconciled to cash flows from operating activities in this section. The derivation of adjusted cash production costs is included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of the Company's MD&A which is incorporated by reference into this document.

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CORPORATE STRUCTURE

Canadian Natural Resources Limited was incorporated under the laws of the Province of British Columbia on November 7,1973 as AEX Minerals Corporation (N.P.L.) and on December 5, 1975 changed its name to Canadian Natural Resources Limited. Canadian Natural was continued under the Companies Act of Alberta on January 6,1982 and was further continued under the Business Corporations Act (Alberta) on November 6,1985. The head, principal and registered office of the Company is located in Calgary, Alberta, Canada at 2100, 855 - 2nd Street S.W., T2P 4J8.

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

October 1, 2000 - Ranger Oil Limited ("Ranger")
January 1, 2003 - Rio Alto Exploration Ltd. ("RAX")
January 1, 2004 - CanNat Resources Inc.
January 1, 2007 - ACC-CNR Resources Corporation
January 1, 2008 - Ranger Oil (International) Ltd.; 764968 Alberta Inc.; CNR International (Norway) Limited; Renata Resources Inc.
January 1, 2012 - Aspect Energy Ltd.; Creo Energy Ltd.; 1585024 Alberta Ltd.
January 1, 2014 - Barrick Energy Inc.
January 1, 2015 - EOG Resources Canada Inc.

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

	Jurisdiction of Incorporation	% Ownership
Subsidiary		
Canadian Natural Upgrading Limited	Alberta	100
CanNat Energy Inc.	Delaware	100
CNR (ECHO) Resources Inc.	Alberta	100
CNR International (U.K.) Investments Limited	England	100
CNR International (U.K.) Limited	England	100
CNR International (Côte d'Ivoire) SARL	Côte d'Ivoire	100
CNR International (Gabon) Limited	Gabon	100
CNR International (South Africa) Limited	Alberta	100
CNR (Redwater) 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
CNRI (Gabon) SCS	Gabon	100

Canadian Natural, as the managing partner, CNR (ECHO) Resources Inc. and Canadian Natural Resources 2005 Partnership are the partners of Canadian Natural Resources, a general partnership. Canadian Natural, as the managing partner, CNR (ECHO) Resources Inc., Canadian Natural Resources and Canadian Natural Resources 2005 Partnership are partners of Canadian Natural Resources Northern Alberta Partnership, a general partnership. Canadian Natural, as the managing partner, and CNR (ECHO) Resources Inc. are the partners of Canadian Natural Resources 2005 Partnership, a general partnership. CNR International (South Africa) Limited, as the limited partner, and CNR International (Gabon) Limited, as the general partner, are the partners of CNRI (Gabon) SCS.

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

The consolidated financial statements of Canadian Natural include the accounts of the Company and all of its subsidiaries and wholly owned partnerships as well as certain of the Company's activities which are conducted through joint arrangements.

GENERAL DEVELOPMENT OF THE BUSINESS

2015

In response to declining commodity prices, the Company’s capital expenditures for 2015 reflected reductions in its capital program by approximately $3,400 million, as well as changes to its capital allocation strategy, including the decrease in drilling activity in North America, partially offset by the planned drilling activities in Offshore Africa.

During 2015, the Company’s existing $1,000 million non-revolving term credit facility was extended, maturing January 2017. The Company also entered into a new $1,500 million non-revolving term credit facility maturing April 2018. Both facilities were fully drawn at December 31, 2015. In addition, the Company’s $1,500 million revolving syndicated credit facility was increased to $2,425 million and the maturity date was extended to June 2019 from June 2016. The $3,000 million revolving syndicated credit facility was reduced to $2,425 million and the maturity date was extended to June 2020 from June 2017. The Company also issued $500 million of series 2 medium-term notes due August 2020 through the reopening of its previously issued 2.89% notes and repaid $400 million of 4.95% medium-term notes.

The Company commenced a review of its royalty lands and royalty revenue portfolio in 2014. The review included a detailed examination of the Company’s freehold and royalty land position, production volumes, product mix, associated cash flow and collection of payments. In the fourth quarter of 2015, the Company disposed of its North America royalty income assets for total consideration of $1,658 million. Total consideration on the disposition was comprised of $673 million in cash, together with $985 million of non-cash consideration, comprised of approximately 44.4 million common shares of PrairieSky Royalty Ltd. ("PrairieSky") with a value of $22.16 per common share determined at the closing date. Subject to certain conditions, including applicable regulatory and/or shareholder approvals, the Company agreed with PrairieSky that, by no later than December 31, 2016, it would distribute sufficient common shares of PrairieSky to the Company’s shareholders so that the Company, after such distribution, would hold less than 10% of the issued and outstanding common shares of PrairieSky.

2016

During 2016, the Company completed the net distribution of approximately 21.8 million PrairieSky common shares to the shareholders of record of the Company as at June 3, 2016, completing the previously announced Plan of Arrangement. The distribution was recognized as a return of capital of $546 million. Subsequent to the distribution, the Company’s ownership interest in PrairieSky was less than 10% of the issued and outstanding common shares of PrairieSky.

During 2016, the Company disposed of its ownership interest in the Cold Lake Pipeline. Net consideration on the disposition was comprised of $349 million in cash, together with $190 million of non-cash share consideration of approximately 6.4 million common shares of Inter Pipeline Ltd. with a value of $29.57 per common share, determined as of the closing date.

During 2016, the Company issued $1,000 million of 3.31% medium term notes due February 2022 and entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn at December 31, 2016. As well, the Company prepaid $250 million of the borrowings outstanding under the previously outstanding $1,000 million non-revolving term credit facility and extended the facility to February 2019 from January 2017. This $750 million facility was fully drawn at December 31, 2016. In addition, the Company repaid US$250 million of 6% notes and US$500 million of three-month LIBOR plus 0.375% notes.

2017

In the third quarter of 2017, the Company acquired assets in the Greater Pelican Lake region and other miscellaneous assets in northern Alberta with production of approximately 19,600 BOE/d, for gross cash consideration of $975 million.

In the fourth quarter of 2017, the Company completed the construction and commissioning of its Horizon Phase 3 expansion.

During 2017, the Company extended $2,095 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021 with the remaining $330 million maturing June 2019 and the Company's $1,500 million non-revolving term credit facility was increased to $2,200 million with the maturity date being extended to October 2019 from

April 2018. As well, the Company repaid US$1,100 million of 5.70% notes. The Company also entered into facilities relating to the AOSP acquisition described under Significant Acquisition.

In December 2017, the Company announced a number of senior management promotions positioning it for continued growth in both the long life low decline assets and low capital exposure assets.

Significant Acquisition

On May 31, 2017, the Company completed its acquisition of a direct and indirect 70% interest in AOSP, including 70% of the Scotford Upgrader, as well as additional working interests in other producing and non-producing oil sands leases. The Company agreed with Shell Canada Limited and certain subsidiaries ("Shell") to acquire its 60% working interest in AOSP including an interest in the mining and extraction operations north of Fort McMurray, Alberta; the Scotford Upgrader and the Quest Carbon Capture and Storage ("CCS") project located north of Edmonton, Alberta; its 100% working interest in its Peace River thermal in situ operations, and its 100% working interest in the Cliffdale heavy oil field as well as other oil sands leases. Canadian Natural and Shell also agreed with Marathon Oil Corporation ("Marathon Oil") to jointly acquire Marathon Oil's 20% share in AOSP and related oil sands investments. In connection with the acquisition, Canadian Natural made offers of employment to approximately 2,800 employees of Shell and Marathon Oil.

Total purchase consideration of $12,541 million, subject to closing adjustments, was comprised of cash payments of $8,217 million, approximately 97.6 million common shares of the Company issued to Shell with a value of approximately $3,818 million determined at the closing date, and deferred purchase consideration of $506 million (US$375 million).

In conjunction with the issuance of approximately $3,818 million of common shares of the Company to Shell, the Company also entered into a $3,000 million non-revolving term credit facility maturing May 2020 to finance the acquisition of AOSP. At December 31, 2017 this facility was fully drawn. As well, the Company issued $1,800 million of medium term notes comprised of $900 million 2.05% notes due June 2020, $600 million 3.42% notes due December 2026 and $300 million 4.85% notes due May 2047. The Company also issued US$3,000 million of debt securities comprised of US$1,000 million 2.95% notes due January 2023, US$1,250 million 3.85% notes due June 2027 and US$750 million 4.95% notes due June 2047.

The Company has filed a Form 51-102F4 in respect of the acquisition.

2018

Subsequent to year end, the Company extended the $750 million non-revolving credit facility originally due February 2019 to February 2021, fully repaid and canceled the $125 million non-revolving credit facility maturing February 2019, repaid and canceled $150 million of the $3,000 million non-revolving term credit facility maturing May 2020, and repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

In March 2018, the Company paid the deferred purchase consideration of US$375 million to Marathon Oil.

DESCRIPTION OF THE BUSINESS

Canadian Natural is a Canadian based senior independent energy company engaged in the acquisition, exploration, development, production, marketing and sale of crude oil, natural gas and NGLs. The Company's principal core regions of operations are western Canada, the UK sector of the North Sea and Offshore Africa.

The Company initiates, operates and maintains a large working interest in a majority of the prospects in which it participates. Canadian Natural's objectives are to increase crude oil 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, 2017, the Company had the following full time equivalent permanent employees:

North America, Exploration and Production	4,496
North America, Oil Sands Mining and Upgrading	5,097
North Sea and Offshore Africa	380
Total Company	9,973

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 and NGLs, light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, SCO from the oil sands mining operations and bitumen (thermal oil). The Company's large diversified project portfolio enables the effective allocation of capital to higher return opportunities, which together provide complementary infrastructure and balance throughout the business cycle. Natural gas accounts for 29% of 2017 production and 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 US. Light and medium crude oil and NGLs, representing 14% of 2017 production, is located in the provinces of Alberta, British Columbia and Saskatchewan and in the Company's North Sea and Offshore Africa properties. Primary heavy crude oil accounting for 10% of 2017 production, Pelican Lake heavy crude oil accounting for 6% of 2017 production, and bitumen (thermal oil) accounting for 12% of 2017 production are in the provinces of Alberta and Saskatchewan. SCO from the oil sands mining operations in Northern Alberta accounted for approximately 29% of 2017 production. Midstream assets, primarily comprised of two operated pipeline systems, and 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. In addition, the Company has entered into agreements for a 20 year transportation agreement to ship 175,000 bbl/d of crude oil on the proposed Trans Canada Keystone XL Pipeline and a 20 year transportation agreement to ship 75,000 bbl/d of crude oil on the proposed Kinder Morgan Trans Mountain Pipeline Expansion.

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, Asset Integrity 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 to conserve high-value diversity. 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. In Canada these requirements apply to all operators in the crude oil and natural gas industry and 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 for air, water and biodiversity, industry operating standards and guidelines, and internal corporate standards. Training and due diligence for operators and contractors are key to the effectiveness of the Company's environmental management systems and the prevention of incidents to protect the environment. 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 through biodiversity protection and restoration 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 carbon capture at hydrotreaters, the injection of CO_2 into tailings and for use in EOR, and the Quest carbon capture and storage facility as part of AOSP; a program in place related to progressive reclamation and tailings management at Horizon including low fines mining; participation and support for the Joint Oil Sands Monitoring Program; and wildlife monitoring and mitigation plans to help maintain biodiversity, as well as mitigation and restoration programs targeted specifically at boreal caribou. 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 2017, Canadian Natural continued its environmental liability reduction program with the abandonment of 771 inactive wells. In addition, reclamation was initiated at many of these sites with the eventual goal of reclamation certification. In 2017 the Company received 1,596 reclamation certificates representing 1,273 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 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 GHG 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, such as provincial and federal methane policy development. 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.

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's integrated GHG emissions reduction strategy includes: integrating emission reduction in project planning and operations; leveraging technology to create value and enhance performance; investing in research and development and supporting collaboration; focusing on continuous improvement to drive long-term emissions reduction; leading in carbon capture and sequestration/storage; engaging proactively in policy and regulatory development (including trading capacity and offsetting emissions); and considering and developing new business opportunities and trends.

The Company continues to implement flaring, venting, fuel and solution gas conservation programs. In 2017, the Company completed approximately 375 gas conservation projects in its primary heavy crude oil operations, resulting in a reduction of approximately 1.9 million tonnes/year of CO_2e. Over the past five years the Company has spent over $91 million in its primary heavy crude oil and in situ oil sands operations to conserve the equivalent of over 17.9 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. The Company has ongoing methane reduction programs for pneumatic devices. 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, the sequestration of CO_2 in oil sands tailings and recovery of hydrocarbon liquids from refinery fuel gas. 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) leases.

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

An Alberta oil sands permit and oil sands primary lease is issued for five and fifteen years respectively. If the minimum level of evaluation of an oil sands permit is attained, a primary oil sands lease will be issued. A primary oil sands lease is continued based on the minimum level of evaluation attained on such lease. Continued primary oil sands leases that are designated as "producing" will continue for their productive lives and are not subject to escalating rentals while those designated as "non-producing" can be continued by payment of escalating rentals.

The provincial governments regulate the production of crude oil and natural gas as well as the removal of natural gas and NGLs from their respective province. Government royalties are payable on crude oil, natural gas and NGLs 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 royalties on oil sands projects 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.

Effective January 1, 2017, the Alberta Government adopted the Modernized Royalty Framework (MRF) for conventional crude oil, natural gas and NGLs royalties. Alberta will have a parallel royalty regime system with the existing Alberta Royalty Framework (ARF) for 10 years until December 31, 2026 and the MRF will apply to wells drilled on or after January 1, 2017. Under the MRF, conventional royalty rates will range from a minimum of 5% to a maximum of 36% for natural gas and NGLs and a minimum 5% to a maximum 40% for crude oil.

The Company is subject to federal and provincial income taxes in Canada at a combined rate of approximately 27% after allowable deductions.

In Canada, the federal government has ratified the Paris climate change agreement, with a commitment to reduce GHG emissions by 30% from 2005 levels by 2030. Under the Pan-Canadian Framework on Clean Growth and Climate Change, the federal and provincial governments will be developing specific policy and regulatory measures to meet Canada's 2030 targets. Canada has also committed to reduce methane emissions from the upstream oil and natural gas sector by 40-45% by 2025, as compared to 2012 levels. The federal government is also developing a comprehensive management system for air pollutants, and has released regulations pertaining to certain boilers, heaters and compressor engines operated by the Company. The federal government is also developing a Clean Fuel Standard with draft regulations expected to be released in 2018. The clean fuel standard will apply to liquid, gaseous and solid fuels combusted for the purpose of creating energy which may affect production and consumption of fuels in Canada.

GHG reduction regulations came into effect July 1, 2007 in Alberta, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. The carbon price in Alberta is currently \$30/tonne for emissions above the regulated limits. Seven of the Company's operated facilities (the Horizon oil sands facility, the Athabasca oil sands facility, the Primrose/Wolf Lake in situ heavy crude oil facilities, the Kirby South in situ heavy crude oil facility, the Peace River in situ heavy crude oil facility, the Hays sour natural gas plant and the Wapiti gas plant) are subject to compliance under the regulation. The non-operated Scotford Upgrader is also subject to compliance under the regulations. The non-operated North West Redwater bitumen upgrader and refinery which will not be subject to a reduction target until 2019. In British Columbia, carbon tax is currently being assessed at \$30/tonne of CO_2e on fuel consumed and gas flared in the province with the rate increasing to \$35/tonne on April 1, 2018. The BC Government will be increasing the carbon tax at a rate of \$5 per tonne of CO_2e annually to \$50 per tonne of CO_2e on April 1, 2021. The Saskatchewan Government has released a Climate Change Strategy that will regulate facilities emitting more than 25 kilotonnes of CO_2e annually and will likely require the North Tangleflags in situ heavy oil facility and the Senlac in situ heavy oil facility to meet reduction targets for GHG emissions once the governing legislation comes into force. The Saskatchewan strategy also includes measures that will regulate GHG emissions (including methane) at below the

25 kilotonne/years threshold.

In 2017, the Alberta provincial government implemented increases in both the carbon price and stringency of the existing large-emitter regulatory system and the carbon pricing for large-emitter systems to $30/tonne. Effective January 1, 2018, the Alberta large-emitter system has changed to a system of output-based allocations (by product type), compared to the previous system of facility-specific baselines. The Alberta Government has also announced a program to reduce methane emissions from the upstream oil and gas sector, and a carbon price on combustion emissions from the upstream oil and gas sector beginning in 2023. In British Columbia, the provincial government has also announced a methane reduction target, comparable to the federal target.

United Kingdom

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

Effective January 1, 2016 the PRT rate, which is a charge on certain crude oil and natural gas profits, was reduced to 0%. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes remain recoverable at 50%. In addition, the supplementary charge on oil and gas profits was reduced to 10%. An Investment Allowance on qualifying capital expenditures is deductible for supplementary charge purposes, subject to certain restrictions. As a result of these changes, the overall tax rate applicable to taxable income from oil and gas activities is 40%.

During 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.

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.

Offshore Africa

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

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

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

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

C. COMPETITIVE FACTORS

The energy industry is highly competitive in all aspects of the business including the exploration for and the development of new sources of supply, the construction and operation of crude oil and natural gas pipelines and related facilities, the acquisition of crude oil and natural gas interests, the transportation and marketing of crude oil, natural gas and NGLs, and electricity and the attraction and retention of skilled personnel. The Company's competitors include both integrated and non-integrated crude oil and natural gas companies as well as other petroleum products and energy sources.

D. RISK FACTORS

Volatility of Crude Oil and Natural Gas Prices

The Company's financial condition is substantially dependent on, and highly sensitive to the prevailing prices of crude oil and natural gas. Significant declines in crude oil or natural gas prices could have a material adverse effect on the Company's operations and financial condition and the value and amount of its reserves. Prices for crude oil and natural gas fluctuate in response to changes in the supply of, and demand for, crude oil and natural gas, market uncertainty and

a variety of additional factors beyond the Company’s control. Crude oil prices are primarily determined by international supply and demand. Factors which affect crude oil prices include the actions of the Organization of Petroleum Exporting Countries, the condition of the Canadian, United States, European and Asian economies, government regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil, the price of foreign imports, the ability to secure adequate transportation for products which could be affected by pipeline constraints, the construction by third parties of new or expansion of existing pipeline capacity and other factors, and the availability of alternate fuel sources and weather conditions. Natural gas prices realized by the Company are affected primarily in North America by supply and demand, weather conditions, industrial demand, and prices of alternate sources of energy. Any substantial or extended decline in the prices of crude oil or natural gas could result in a delay or cancellation of existing or future drilling, development or construction programs, including but not limited to Horizon, AOSP, Primrose, Pelican Lake, the Kirby Thermal Oil Sands Project, the North West Redwater bitumen upgrader and refinery and international projects, or curtailment in production at some properties, or result in unutilized long-term transportation commitments, all of which could have a material adverse effect on the Company’s financial condition.

Approximately 28% of the Company’s 2017 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 currently differs 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 currently differs from the benchmark they are priced against. Future quality differentials are uncertain and a significant increase in differential could have a material adverse effect on the Company’s financial condition.

Canadian Natural conducts periodic 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 related property, plant and equipment could be subject to downward revisions, and net earnings could be adversely affected.

Operational Risk

Exploring for, producing, mining, extracting, upgrading and transporting crude oil, natural gas and NGLs involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. These activities are subject to a number of hazards which may result in fires, explosions, spills, blow outs or other unexpected or dangerous conditions causing personal injury, property damage, environmental damage, interruption of operations and loss of production, whether caused by human error or nature. In addition to the foregoing, the oil sands mining and upgrading 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, African and other national, 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. In respect of its offshore operations, the Company also participates with regulators and industry partners in addressing environmental monitoring and emergency response protocols that are applicable to the Company's operations in these jurisdictions. 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 may have a material adverse effect on the Company's financial condition. Current and potential climate change policies and regulations are considered when making decisions to advance the Company's business strategy. The Company is tracking the development of policies and regulations at the national and provincial level. The Government of Alberta has proceeded with implementing the measures in the Climate Leadership Plan that were announced November 2015, including measures to reduce methane emissions, implement an emissions limit for oil sands, introduce a broad-based carbon price (with phase-in for the upstream industry), and modification of the existing regulatory system for large emitting facilities. The Company continues to pursue GHG emission reduction initiatives including: solution gas conservation, compressor optimization to improve fuel gas efficiency, reductions in pneumatic devices, CO_2 capture and sequestration in oil sands tailings, CO_2 capture and storage in association with EOR, CO_2 capture and storage at Quest, and participation in COSIA.

Various jurisdictions have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oils with higher emissions intensity. In March 2016 the US and Canadian governments issued a joint statement regarding a commitment to lowering methane emissions from the oil and natural gas sector by 2025. The Canadian government and certain provincial governments are currently developing regulations to reduce methane emissions, in support of the announced methane reduction targets.

The additional requirements of enacted or proposed GHG regulations on the Company's operations may increase capital expenditures and production expense, including those related to the Company's existing and planned oil sands projects. 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 March 2015, Alberta Environment and Parks released the Tailings Management Framework (TMF) policy. In July 2016, the Alberta Energy Regulator (AER), released Directive 85 - Fluid Tailings Management for Oil Sands Mining Projects which was updated in October 2017. The Directive establishes performance criteria for tailings operations and sets out the requirements for approval, monitoring and reporting in respect of tailings ponds and tailings management plans. The Company submitted an updated Tailings Management Plan application for Horizon in September 2016 to meet the proposed Directive criteria. In December 2017, the Horizon Tailings Management Plan (TMP) was approved including the key technology tailings treatment technology and fluid tailings profile presented in the application. The Horizon TMP approval stipulates additional requirements in relation to the development of alternative tailings treatment technology for water-capped tailings, additional submissions for implementation of the key stages of the TMP, and increased stakeholder engagement activities specifically in relation to tailings management activities. In October 2016, Shell submitted TMP Applications for the Muskeg River Mine and Jackpine Mine. In December 2017, the AER issued draft approval conditions for both mines. Final approvals are anticipated in 2018.

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 reserves 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 funds flow from operations are insufficient to fund capital expenditures and external sources of capital become limited or unavailable, the Company's ability to make the necessary capital investments to maintain and expand its crude oil and natural gas reserves will be impaired. In addition, Canadian Natural may be unable to find and develop or acquire additional reserves to replace its crude oil and natural gas production at acceptable costs.

Uncertainty of Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the Company's control. In general, estimates of economically recoverable crude oil, natural gas and NGLs 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 reserves 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, production costs and the timing and amount of future development expenditures, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable crude oil, natural gas and NGLs 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.

Project Risk

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

Sources of Liquidity

The ability to fund current and future capital projects and carry out the business plan is dependent on Canadian Natural's ability to generate cash flow as well as raise capital in a timely manner under favourable terms and conditions and is impacted by the Company's credit ratings and the condition of the capital and credit markets. In addition, changes in credit ratings may affect the 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. The Company also enters into various transactions with counterparties and is subject to credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts.

Dividends

The Company's payment of future dividends on common shares is dependent on, among other things, its financial condition and other business factors considered relevant by the Board of Directors. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

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 of crude oil and natural gas properties in other foreign jurisdictions. 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 reserves 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 periodically 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.

Information Technology

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. Notwithstanding the Company's proactive approach to combating cybersecurity threats, such threats frequently change and require evolving monitoring and detection efforts. Examples of such threats include unauthorized access to information technology systems due to social engineering, hacking, viruses and other causes. A successful cyber-attack could result in the loss, disclosure or theft of confidential information related to the Company's proprietary business activities and the personnel files of its employees. The Company has implemented cybersecurity protocols and procedures to address this risk.

Other Business Risks

Other business risks which may negatively impact the Company's financial condition include regulatory issues, risk of increases in government taxes and changes to royalty regimes, risk of litigation, risk to the Company's reputation resulting from operational activities that may cause personal injury, property damage or environmental damage, labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner, severe weather conditions, timing and success of integrating the business and operations of acquired companies and businesses, and the dependency on third party operators for certain of the Company's assets. 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, 2017, the Company retained Independent Qualified Reserves Evaluators (“IQRE”), Sproule Associates Limited and Sproule International Limited (together as “Sproule”) and GLJ Petroleum Consultants Ltd. (“GLJ”), to evaluate and review all of the Company’s proved and proved plus probable reserves with an effective date of December 31, 2017 and a preparation date of February 7, 2018. Sproule evaluated and reviewed 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 and reviewed the AOSP SCO reserves. The evaluations and reviews were conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (“COGE Handbook”) and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI 51-101”) requirements.

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

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 “Extractive Activities - Oil and Gas” in the Company’s annual report on Form 40-F filed with the SEC in the “Supplementary Oil and Gas Information” section of the Company’s Annual Report on pages 96 to 105 which is incorporated herein by reference.

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

There is no assurance that the price and cost assumptions contained in the forecast case will be attained and variances could be material. The recovery and reserves estimates of crude oil, natural gas and NGLs reserves provided herein are estimates only and there is no guarantee the estimated reserves will be recovered. Actual crude oil, natural gas and NGLs reserves may be greater or less than the estimate provided herein. See "Special Note Regarding Forward-Looking Statements", "Special Note Regarding Currency, Financial Information, Production and Reserves", and "Risk Factors".

Principal Documents Exhibits

Summary of Company Gross Reserves
As of December 31, 2017
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	114	108	266	322	5,264	4,029	102	6,848
Developed Non-Producing	11	15	—	34	—	347	8	126
Undeveloped	46	75	61	994	—	2,354	119	1,687
Total Proved	171	198	327	1,350	5,264	6,730	229	8,661
Probable	68	74	142	1,230	799	2,790	106	2,884
Total Proved plus Probable	239	272	469	2,580	6,063	9,520	335	11,545
North Sea								
Proved								
Developed Producing	25					17		28
Developed Non-Producing	4					—		4
Undeveloped	91					4		92
Total Proved	120					21		124
Probable	60					11		61
Total Proved plus Probable	180					32		185
Offshore Africa								
Proved								
Developed Producing	30					12		32
Developed Non-Producing	2					—		2
Undeveloped	51					8		52
Total Proved	83					20		86
Probable	42					47		50
Total Proved plus Probable	125					67		136
Total Company								
Proved								
Developed Producing	169	108	266	322	5,264	4,058	102	6,908
Developed Non-Producing	17	15	—	34	—	347	8	132
Undeveloped	188	75	61	994	—	2,366	119	1,831
Total Proved	374	198	327	1,350	5,264	6,771	229	8,871
Probable	170	74	142	1,230	799	2,848	106	2,995

Total Proved plus Probable	544	272	469	2,580	6,063	9,619	335	11,866

Summary of Company Net Reserves
As of December 31, 2017
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	103	91	207	262	4,552	3,654	80	5,904
Developed Non-Producing	10	13	—	28	—	312	6	109
Undeveloped	39	65	50	825	(9)	2,066	101	1,415
Total Proved	152	169	257	1,115	4,543	6,032	187	7,428
Probable	58	61	101	971	653	2,422	86	2,334
Total Proved plus Probable	210	230	358	2,086	5,196	8,454	273	9,762
North Sea								
Proved								
Developed Producing	25					17		28
Developed Non-Producing	4					—		4
Undeveloped	91					4		92
Total Proved	120					21		124
Probable	60					11		61
Total Proved plus Probable	180					32		185
Offshore Africa								
Proved								
Developed Producing	27					9		29
Developed Non-Producing	2					—		2
Undeveloped	41					6		42
Total Proved	70					15		73
Probable	32					32		37
Total Proved plus Probable	102					47		110
Total Company								
Proved								
Developed Producing	155	91	207	262	4,552	3,680	80	5,961
Developed Non-Producing	16	13	—	28	—	312	6	115
Undeveloped	171	65	50	825	(9)	2,076	101	1,549
Total Proved	342	169	257	1,115	4,543	6,068	187	7,625
Probable	150	61	101	971	653	2,465	86	2,432

Total Proved plus Probable	492	230	358	2,086	5,196	8,533	273	10,057

NOTES

1. "Company gross reserves" are Canadian Natural's working interest share of reserves before deduction of royalties and without including any royalty interests of the Company.
2. "Company net reserves" are the company gross reserves less all royalties payable to others plus royalties receivable from others.
3. References to "light and medium crude oil" means "light crude oil and medium crude oil combined".
4. "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 reserves 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 significant 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.

5. The reserves evaluation involved data supplied by the Company with respect to geological and engineering data, adjustments for product quality, heating value and transportation, interests owned, royalties payable, production costs, capital costs and contractual commitments. This data was found by the IQRE to be reasonable.
6. BOE values as presented may not calculate due to rounding.

A report on reserves data by the IQREs is provided in Schedule "A" to this AIF. A report by the Company's management and directors on crude oil, natural gas and NGLs reserves disclosure is provided in Schedule "B" to this AIF.

Summary of Net Present Values of Future Net Revenue Before Income Taxes
As of December 31, 2017
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	243,068	110,905	67,045	48,105	37,976	11.36
Developed Non-Producing	2,577	1,580	1,138	888	726	10.44
Undeveloped	41,854	27,628	17,077	10,958	7,345	12.07
Total Proved	287,499	140,113	85,260	59,951	46,047	11.48
Probable	121,319	43,480	21,517	13,198	9,223	9.22
Total Proved plus Probable	408,818	183,593	106,777	73,149	55,270	10.94
North Sea						
Proved						
Developed Producing	(951)	101	389	466	480	13.89
Developed Non-Producing	128	113	99	90	81	24.75
Undeveloped	4,225	3,068	2,319	1,807	1,444	25.21
Total Proved	3,402	3,282	2,807	2,363	2,005	22.64
Probable	4,977	2,952	1,957	1,408	1,075	32.08
Total Proved plus Probable	8,379	6,234	4,764	3,771	3,080	25.75
Offshore Africa						
Proved						
Developed Producing	558	671	664	625	581	22.90
Developed Non-Producing	113	95	82	72	64	41.00
Undeveloped	2,355	1,474	987	699	518	23.50
Total Proved	3,026	2,240	1,733	1,396	1,163	23.74
Probable	2,790	1,753	1,191	862	654	32.19
Total Proved plus Probable	5,816	3,993	2,924	2,258	1,817	26.58
Total Company						
Proved						
Developed Producing	242,675	111,677	68,098	49,196	39,037	11.42
Developed Non-Producing	2,818	1,788	1,319	1,050	871	11.47
Undeveloped	48,434	32,170	20,383	13,464	9,307	13.16
Total Proved	293,927	145,635	89,800	63,710	49,215	11.78
Probable	129,086	48,185	24,665	15,468	10,952	10.14
Total Proved plus Probable	423,013	193,820	114,465	79,178	60,167	11.38

(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, 2017
Forecast Prices and Costs

MM$	Discount @ 0%	Discount @ 5%	Discount @ 10%	Discount @ 15%	Discount @ 20%
North America					
Proved					
Developed Producing	180,072	84,460	52,068	37,872	30,189
Developed Non-Producing	1,924	1,152	819	633	514
Undeveloped	30,482	19,719	11,896	7,388	4,743
Total Proved	212,478	105,331	64,783	45,893	35,446
Probable	88,808	31,587	15,521	9,462	6,577
Total Proved plus Probable	301,286	136,918	80,304	55,355	42,023
North Sea					
Proved					
Developed Producing	(553)	93	268	314	322
Developed Non-Producing	128	78	61	54	49
Undeveloped	2,628	1,921	1,462	1,148	924
Total Proved	2,203	2,092	1,791	1,516	1,295
Probable	2,977	1,785	1,196	868	669
Total Proved plus Probable	5,180	3,877	2,987	2,384	1,964
Offshore Africa					
Proved					
Developed Producing	423	558	567	540	506
Developed Non-Producing	106	90	78	69	61
Undeveloped	1,812	1,148	778	557	418
Total Proved	2,341	1,796	1,423	1,166	985
Probable	2,098	1,329	911	665	508
Total Proved plus Probable	4,439	3,125	2,334	1,831	1,493
Total Company					
Proved					
Developed Producing	179,942	85,111	52,903	38,726	31,017
Developed Non-Producing	2,158	1,320	958	756	624
Undeveloped	34,922	22,788	14,136	9,093	6,085
Total Proved	217,022	109,219	67,997	48,575	37,726
Probable	93,883	34,701	17,628	10,995	7,754
Total Proved plus Probable	310,905	143,920	85,625	59,570	45,480

(1) After-tax net present values consider the Company's existing tax pool balances and current tax regulations and do not represent an estimate of the value at the consolidated entity level, which may be significantly different. For information at the consolidated entity level, refer to the Company's Consolidated Financial Statements and the Management's Discussion and Analysis for the year ended December 31, 2017.

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Additional Information Concerning Future Net Revenue

The following table summarizes the undiscounted future net revenue as at December 31, 2017 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	790,335	1,059,460	12,580	19,983	6,733	10,007	809,648	1,089,450
Royalties	116,242	168,851	25	41	214	343	116,481	169,235
Production Costs	307,360	385,552	5,709	7,628	2,243	2,273	315,312	395,453
Development Costs	67,366	83,261	1,726	2,217	855	1,130	69,947	86,608
Abandonment and Reclamation Costs – Future Development (1)	548	802	—	—	42	92	590	894
Abandonment and Reclamation Costs – Existing Development (1)	11,320	12,176	1,718	1,718	353	353	13,391	14,247
Future Net Revenue Before Income Taxes	287,499	408,818	3,402	8,379	3,026	5,816	293,927	423,013
Income Taxes	75,021	107,532	1,199	3,199	685	1,377	76,905	112,108
Future Net Revenue After Income Taxes (2)	212,478	301,286	2,203	5,180	2,341	4,439	217,022	310,905

(1) Abandonment and reclamation costs included in the calculation of the future net revenue for 2017 consist of both forecast estimates of abandonment and reclamation costs attributable to future development activity, as well as certain costs already included in the Company's ARO for development existing as at December 31, 2017. The Company's estimated ARO at December 31, 2017 was $12,656 million, unescalated and undiscounted (escalated and discounted at 10%, ARO at December 31, 2017 was $1,473 million). Approximately $6,526 million of this unescalated and undiscounted amount was also included in the future net revenue and is escalated at 2.0% per year after 2018. Specifically, for North America (excluding SCO assets), future net revenue includes the costs associated with abandonment and reclamation of wells (wells, well sites, well site equipment and pipelines) with assigned reserves. For SCO assets, future net revenue includes the costs associated with the abandonment and reclamation of the mine site and all mining facilities and for Horizon assets, future net revenue also includes abandonment and reclamation of the upgrading facilities. For North Sea and Offshore Africa, future net revenue includes the costs associated with the abandonment and reclamation of offshore wells and facilities with assigned reserves.

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

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The following table summarizes the future net revenue by product type as at December 31, 2017 using forecast prices and costs.

Future Net Revenue By Product Type (1) (2)

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (discounted at 10%/year) (MM$)	Unit Value ($/BOE)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	9,093	20.82
	Primary Heavy Crude Oil (including solution gas)	3,028	17.69
	Pelican Lake Heavy Crude Oil (including solution gas)	4,315	16.70
	Bitumen (Thermal Oil)	13,741	12.32
	Synthetic Crude Oil	51,904	11.43
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	8,690	7.89
	Abandonment and Reclamation Costs – Existing Development	(971)	
	Total	89,800	11.78
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	14,009	21.87
	Primary Heavy Crude Oil (including solution gas)	4,288	18.43
	Pelican Lake Heavy Crude Oil (including solution gas)	5,872	16.34
	Bitumen (Thermal Oil)	20,472	9.81
	Synthetic Crude Oil	59,193	11.39
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	11,650	7.55
	Abandonment and Reclamation Costs – Existing Development	(1,019)	
	Total	114,465	11.38

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

(2) The net present values of the future net revenue for each product type includes the forecast estimates of abandonment and reclamation costs attributable to future development activity. The net present value of the future net revenue for the “Abandonment and Reclamation Costs – Existing Development” contains certain costs already included in the Company’s ARO for development existing as at December 31, 2017, which are not applied at the product type level.

Pricing Assumptions

The crude oil, natural gas and NGLs 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, 2017. The following is a summary of the Sproule price forecast.

	2018	2019	2020	2021	2022	Average annual increase thereafter
Crude Oil and NGLs						
WTI [(1)] (US$/bbl)	$55.00	$65.00	$70.00	$73.00	$74.46	2.00 %
WCS [(2)] (C$/bbl)	$51.05	$59.61	$64.94	$68.43	$69.80	2.00 %
Canadian Light Sweet [(3)] (C$/bbl)	$65.44	$74.51	$78.24	$82.45	$84.10	2.00 %
Cromer LSB [(4)] (C$/bbl)	$64.44	$73.51	$77.24	$81.45	$83.10	2.00 %
Edmonton C5+ [(5)] (C$/bbl)	$67.72	$75.61	$78.82	$82.35	$84.07	2.00 %
North Sea Brent [(6)] (US$/bbl)	$58.00	$67.00	$72.00	$75.00	$76.50	2.00 %
Natural Gas						
AECO [(7)] (C$/MMBtu)	$2.85	$3.11	$3.65	$3.80	$3.95	2.00 %
BC Westcoast Station 2 [(8)] (C$/MMBtu)	$2.45	$2.71	$3.25	$3.40	$3.55	2.00 %
Henry Hub [(9)] (US$/MMBtu)	$3.25	$3.50	$4.00	$4.08	$4.16	2.00 %

(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) "Canadian Light Sweet" refers to the price of light gravity (40˚ API), low sulphur content Mixed Sweet Blend (MSW) crude oil at Edmonton, Alberta; reference price used in the preparation of light and medium crude oil and SCO reserves.

(4) "Cromer LSB" refers to the price of light sour blend (35˚ API) physical crude oil at Cromer, Manitoba; reference price used in the preparation of light and medium crude oil in SE Saskatchewan and SW Manitoba reserves.

(5) "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.

(6) "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.

(7) "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.

(8) "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.

(9) "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 0.79 US$/C$ for 2018, 0.82 US$/C$ for 2019, and 0.85 US$/C$ after 2019 was used in the 2017 evaluation.

Production and capital costs are escalated at Sproule's cost inflation rate of 0% per year for 2018 and 2% per year after 2018 for all products.

The Company's 2017 average pricing, net of blending costs and excluding risk management activities, was $63.23/bbl for light and medium crude oil, $46.88/bbl for primary heavy crude oil, $48.30/bbl for Pelican Lake heavy crude oil, $42.49/bbl for bitumen (thermal oil), $63.98/bbl for SCO, $34.44/bbl for NGLs and $2.76/Mcf for natural gas.

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Reconciliation of Company Gross Reserves
As of December 31, 2017
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, 2016	168	187	264	1,269	2,559	6,545	198	5,736
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	14	—	20	—	276	15	99
Infill Drilling	4	7	—	—	—	191	17	60
Improved Recovery	—	1	1	—	—	1	—	2
Acquisitions	6	20	76	23	2,321	116	1	2,467
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	(25)	—	(4)
Technical Revisions	7	4	5	82	487	211	13	633
Production	(18)	(35)	(19)	(44)	(103)	(585)	(15)	(332)
December 31, 2017	171	198	327	1,350	5,264	6,730	229	8,661

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	134	41	141
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	—	—	—
Improved Recovery	—	—	—
Acquisitions	—	—	—
Dispositions	—	—	—
Economic Factors	4	(5)	3
Technical Revisions	(9)	(1)	(9)
Production	(9)	(14)	(11)
December 31, 2017	120	21	124

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	87	31	92
Discoveries	—	—	—
Extensions	—	—	—

Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	3					(3)		2
Production	(7)					(8)		(8)
December 31, 2017	83					20		86
Total Company								
December 31, 2016	389	187	264	1,269	2,559	6,617	198	5,969
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	14	—	20	—	276	15	99
Infill Drilling	4	7	—	—	—	191	17	60
Improved Recovery	—	1	1	—	—	1	—	2
Acquisitions	6	20	76	23	2,321	116	1	2,467
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	4	—	—	—	—	(30)	—	(1)
Technical Revisions	1	4	5	82	487	207	13	626
Production	(34)	(35)	(19)	(44)	(103)	(607)	(15)	(351)
December 31, 2017	374	198	327	1,350	5,264	6,771	229	8,871

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PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	65	72	120	1,248	1,045	2,366	86	3,030
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	8	—	19	—	278	10	88
Infill Drilling	2	3	—	—	—	104	9	31
Improved Recovery	—	—	1	—	—	—	—	1
Acquisitions	2	6	23	27	175	29	—	237
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	1	—	—	—	—	(4)	—	1
Technical Revisions	(6)	(15)	(2)	(64)	(421)	18	1	(504)
Production	—	—	—	—	—	—	—	—
December 31, 2017	68	74	142	1,230	799	2,790	106	2,884
North Sea								
December 31, 2016	119					44		126
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	1					—		1
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	(4)					5		(3)
Technical Revisions	(56)					(38)		(63)
Production	—					—		—
December 31, 2017	60					11		61
Offshore Africa								
December 31, 2016	46					49		54
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—

Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	(4)					(2)		(4)
Production	—					—		—
December 31, 2017	42					47		50
Total Company								
December 31, 2016	230	72	120	1,248	1,045	2,459	86	3,210
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	8	—	19	—	278	10	88
Infill Drilling	3	3	—	—	—	104	9	32
Improved Recovery	—	—	1	—	—	—	—	1
Acquisitions	2	6	23	27	175	29	—	237
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	(3)	—	—	—	—	1	—	(2)
Technical Revisions	(66)	(15)	(2)	(64)	(421)	(22)	1	(571)
Production	—	—	—	—	—	—	—	—
December 31, 2017	170	74	142	1,230	799	2,848	106	2,995

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PROVED PLUS PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	233	259	384	2,517	3,604	8,911	284	8,766
Discoveries	—	—	—	—	—	—	—	—
Extensions	8	22	—	39	—	554	25	187
Infill Drilling	6	10	—	—	—	295	26	91
Improved Recovery	—	1	2	—	—	1	—	3
Acquisitions	8	26	99	50	2,496	145	1	2,704
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	1	—	—	—	—	(29)	—	(3)
Technical Revisions	1	(11)	3	18	66	229	14	129
Production	(18)	(35)	(19)	(44)	(103)	(585)	(15)	(332)
December 31, 2017	239	272	469	2,580	6,063	9,520	335	11,545

North Sea	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, 2016	253					85		267
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	1					—		1
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	(65)					(39)		(72)
Production	(9)					(14)		(11)
December 31, 2017	180					32		185

Offshore Africa	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, 2016	133					80		146
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—

Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	(1)					(5)		(2)
Production	(7)					(8)		(8)
December 31, 2017	125					67		136
Total Company								
December 31, 2016	619	259	384	2,517	3,604	9,076	284	9,179
Discoveries	—	—	—	—	—	—	—	—
Extensions	8	22	—	39	—	554	25	187
Infill Drilling	7	10	—	—	—	295	26	92
Improved Recovery	—	1	2	—	—	1	—	3
Acquisitions	8	26	99	50	2,496	145	1	2,704
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	1	—	—	—	—	(29)	—	(3)
Technical Revisions	(65)	(11)	3	18	66	185	14	55
Production	(34)	(35)	(19)	(44)	(103)	(607)	(15)	(351)
December 31, 2017	544	272	469	2,580	6,063	9,619	335	11,866

(1) Discoveries are additions to reserves in reservoirs where no reserves were previously booked.

(2) Extensions are additions to reserves resulting from step-out drilling or recompletions.

(3) Infill Drilling are additions to reserves resulting from drilling or recompletions within the known boundaries of a reservoir.

(4) Improved Recovery are additions to reserves resulting from the implementation of improved recovery schemes.

(5) Negative volumes, if any, for probable reserves result from the transfer of probable reserves to proved reserves. If reserves previously assigned to a discovery, an extension, an infill drilling, or an improved recovery reserves change category are initially classified as probable, they may be classified as a proved addition, in the same reserves change category, in the year when the reserves are reclassified as proved.

(6) Economic Factors are changes primarily due to price forecasts.

(7) Technical Revisions include changes in previous estimates resulting from new technical data or revised interpretations.

2017 total Proved Crude Oil, Bitumen and NGLs reserves increased by 2,876 MMbbl primarily due to the following:
Extensions: Increase of 53 MMbbl primarily due to future Bitumen well pad additions at Primrose and extension drilling/future offset additions at various Primary Heavy Crude Oil and natural gas (NGLs) properties.
Infill Drilling: Increase of 28 MMbbl primarily due to infill drilling/future offset additions at various Primary Heavy Crude Oil and natural gas (NGLs) properties.
Improved Recovery: Increase of 2 MMbbl.
Acquisitions: Increase of 2,447 MMbbl primarily due to property acquisitions at Cliffdale (Primary Heavy Crude Oil), Pelican Lake (Pelican Lake Heavy Crude Oil), Peace River (Bitumen) and AOSP (SCO).
Economic Factors: Increase of 4 MMbbl.
Technical Revisions: Increase of 592 MMbbl primarily due to Horizon (SCO) revising the stratigraphic well density used to define proved and probable reserves quantities, increasing the Horizon (SCO) total-volume-to-bitumen-in-place ratio, partially offset by Horizon (SCO) adopting a low fines mine plan. Additionally, there were overall positive revisions at several North America Crude Oil, Bitumen and natural gas (NGLs) core areas including the transfer of probable reserves to proved reserves due to improved recoveries at Primrose (Bitumen).
Production: Decrease of 250 MMbbl.

2017 total Proved Natural Gas reserves increased by 154 Bcf primarily due to the following:
Extensions: Increase of 276 Bcf primarily due to extension drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
Infill Drilling: Increase of 191 Bcf primarily due to infill drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
Improved Recovery: Increase of 1 Bcf.
Acquisitions: Increase of 116 Bcf primarily due to property acquisitions in North America core areas.
Economic Factors: Decrease of 30 Bcf due to the loss of uneconomic reserves at several North America Natural Gas areas.
Technical Revisions: Increase of 207 Bcf primarily due to overall positive revisions at several North America core areas triggered by production optimizations and reduced operating costs.
Production: Decrease of 607 Bcf.

2017 total Proved plus Probable Crude Oil, Bitumen and NGLs reserves increased by 2,596 MMbbl primarily due to the following:
Extensions: Increase of 94 MMbbl primarily due to future Bitumen well pad additions at Primrose and extension drilling/future offset additions at various Primary Heavy Crude Oil and natural gas (NGLs) properties.
Infill Drilling: Increase of 43 MMbbl primarily due to infill drilling/future offset additions at various Primary Heavy Crude Oil and natural gas (NGLs) properties.
Improved Recovery: Increase of 3 MMbbl.
Acquisitions: Increase of 2,680 MMbbl primarily due to property acquisitions at Cliffdale (Primary Heavy Crude Oil), Pelican Lake (Pelican Lake Heavy Crude Oil), Peace River (Bitumen) and AOSP (SCO).
Economic Factors: Increase of 1 MMbbl.
Technical Revisions: Increase of 25 MMbbl primarily due to Horizon (SCO) increasing the total-volume-to-bitumen-in-place ratio, partially offset by Horizon (SCO) adopting a low fines mine plan. Additionally, there were overall negative revisions at several North America Crude Oil areas offset by positive revisions at Bitumen and natural gas (NGLs) core areas.
Production: Decrease of 250 MMbbl.

2017 total Proved plus Probable Natural Gas reserves increased by 543 Bcf primarily due to the following:
Extensions: Increase of 554 Bcf primarily due to extension drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.

Infill Drilling: Increase of 295 Bcf primarily due to infill drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
Improved Recovery: Increase of 1 Bcf.
Acquisitions: Increase of 145 Bcf primarily due to property acquisitions in North America core areas.

Dispositions: Decrease of 1 Bcf.
Economic Factors: Decrease of 29 Bcf due to the loss of uneconomic reserves at several North America Natural Gas areas.
Technical Revisions: Increase of 185 Bcf primarily due to overall positive revisions at several North America core areas triggered by production optimizations and reduced operating costs.
Production: Decrease of 607 Bcf.

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 IQRE 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)
2015								
First Attributed	3	4	—	29	125	487	15	257
Total	201	81	42	874	125	1,931	90	1,735
2016								
First Attributed	14	3	—	55	—	282	13	132
Total	192	76	50	934	15	2,117	89	1,709
2017								
First Attributed	5	10	9	21	—	416	30	144
Total	188	75	61	994	—	2,366	119	1,831

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)
2015 First Attributed	4	3	—	90	4	507	26	212
Total	164	46	26	968	1,043	1,176	57	2,500
2016								
First Attributed	10	2	—	30	—	130	8	72
Total	147	42	27	1,023	240	1,214	54	1,735
2017								
First Attributed	6	7	1	19	—	366	19	113
Total	97	41	26	1,006	—	1,561	73	1,503

Bitumen (thermal oil) accounts for approximately 54% of the Company’s total proved undeveloped BOE reserves and 67% 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 approximately the next thirty 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 approximately the next ten years. The Company continually reviews the capital allocation, operational capacities and ranking of these undeveloped reserves within the total portfolio of development projects.

Principal Documents Exhibits

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, 2017.

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$)	Proved plus Probable (MM$)
2018	2,689	2,866	149	155	87	226	2,925	3,247
2019	3,622	3,989	187	194	101	112	3,910	4,295
2020	3,064	3,297	162	166	54	66	3,280	3,529
2021	3,043	3,340	147	156	121	216	3,311	3,712
2022	3,415	3,759	153	158	39	53	3,607	3,970
Thereafter	51,533	66,010	928	1,388	453	457	52,914	67,855
Total	67,366	83,261	1,726	2,217	855	1,130	69,947	86,608

(1) Total Future Development Costs discounted at 10% are:

North America		North Sea		Offshore Africa		Total	
Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)	Proved (MM$)	Proved plus Probable (MM$)
23,472	27,087	968	1,095	528	757	24,968	28,939

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

Principal Documents Exhibits

Other Oil and Gas Information

Daily Production

Set forth below is a summary of the production, before royalties, from crude oil, natural gas and NGLs properties for the fiscal years ended December 31, 2017 and 2016.

Region	2017 Average Daily Production Rates		2016 Average Daily Production Rates	
	Crude Oil & NGLs (Mbbl)	Natural Gas (MMcf)	Crude Oil & NGLs (Mbbl)	Natural Gas (MMcf)
North America				
Northeast British Columbia	13	397	14	420
Northwest Alberta	42	662	40	677
Northern Plains	280	223	274	240
Southern Plains	19	316	17	282
Southeast Saskatchewan	6	3	6	3
Oil Sands Mining & Upgrading	282	—	123	—
North America Total	642	1,601	474	1,622
International				
North Sea UK Sector	23	39	24	38
Offshore Africa	20	22	26	31
International Total	43	61	50	69
Company Total	685	1,662	524	1,691

Northeast British Columbia

The Northeast British Columbia Region holds a significant portion of the Montney formation. This formation produces liquids rich natural gas and light oil from several stratigraphic intervals. The exploration strategy focuses on comprehensive evaluation through two dimensional seismic, three dimensional seismic and targeting economic prospects close to existing infrastructure. This area includes a natural gas processing plant with a design capacity of 145 MMcf/d and 11,000 bbl/d of NGLs at our Septimus Montney liquids rich natural gas and light oil play as well as a pipeline to a deep cut gas facility. 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 structural area.

Principal Documents Exhibits

Northwest Alberta

This region is located along the border of British Columbia and Alberta west of Edmonton, Alberta and provides a premium land base in the deep basin, multi-zone liquids rich natural gas and light oil fairway. Northwest Alberta has a significant Montney and Spirit River land base, and 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. Locations are identified with two dimensional and three dimensional seismic to predict channel and shoreface fairways. The southwestern 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, light crude oil and NGLs 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 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 78,000 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 and its associated disposal requirements, as well as the gathering and pipeline facilities in place. An acquisition in late third quarter 2017 added approximately 19,000 bbl/d of production and the Company has the major ownership position in the necessary infrastructure, 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 100% owned and operated Pelican Lake Pipeline and four major oil batteries with a capacity of 95,000 bbl/d. The Company is using an EOR scheme through polymer flooding to increase the ultimate recoveries from the field. At the end of 2017, approximately 56% of the field had been converted to polymer injection on an area basis.

Production of bitumen (thermal oil) from the 100% owned Primrose Field located near Bonnyville, Alberta and Kirby South field located near Lac la Biche, Alberta, involves processes that utilize steam to increase the recovery of the bitumen (averaging 8°-11° API). The processes employed by the Company are CSS, SAGD, and steamflood. These 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 and two processing plants (Wolf Lake and Kirby South) with capacity of 170,000 bbl/d. The Company also holds a 50% interest in a co-generation facility capable of producing 84 megawatts of electricity. The Company continues to optimize the CSS process which results in a significant improvement in well productivity and in ultimate bitumen recovery.

The Kirby North Phase 1 project received all regulatory permits with facility construction commencing in the third quarter of 2014. In 2015, in response to declining commodity prices, the Company chose to temporarily delay spending on major construction activities on the Kirby North Project. In 2016, the Company re-initiated the development of the Kirby North Project and engineering and procurement commenced in 2017. The overall project is approximately 58% complete.

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 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 southeastern portion of the province extending into Manitoba and 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 Horizon oil sands leases which are located about 70 kilometers north of Fort McMurray, Alberta, of which the main lease is subject to a 5% net carried interest in the bitumen development. 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 SCO is transported from the site by pipeline to the Edmonton area for distribution. Two on-site cogeneration plants with a combined design capacity of 182 megawatts provide power and steam for the operations.

The Company received project sanction by the Board of Directors in February 2005, authorizing management to proceed with Phase 1 of Horizon with a design capacity of 110,000 bbl/d. First SCO production was achieved during 2009.

In 2014, the Company completed the Phase 2A coker plant tie-in, followed by the Phase 2B expansion in the third quarter of 2016. In the fourth quarter of 2017, the Company completed the Phase 3 expansion bringing total production capacity to approximately 250,000 bbl/d.

In May 2017, the Company acquired a combined direct and indirect 70% interest in AOSP which is an oil sands mining and upgrading joint venture located in Alberta, Canada. The Company operates AOSP's mining and extraction assets which are located in the Athabasca region near Fort McMurray, Alberta, and include the Muskeg River and the Jackpine mines. Shell operates the Scotford Upgrader, including the Quest Carbon Capture and Storage ("CCS") project, which is located near Fort Saskatchewan, northeast of Edmonton, Alberta and utilizes LC FINING technology to efficiently hydrocrack residuum to high-quality fuel oils and transportation fuels.

Bitumen is produced from the oil sands deposits using conventional truck and shovel technology. The ore is then processed through extraction and froth treatment facilities to produce bitumen. Diluted bitumen blend from the Muskeg River and Jackpine mines is transported to the Scotford Upgrader on the Corridor Pipeline where the bitumen is upgraded into Premium Albian Synthetic crude oil, Albian Heavy Synthetic crude oil and Vacuum Gas Oil and, in certain circumstances, other heavy blends. Diluent is transported from the Scotford Upgrader back to the Muskeg River mine through the combined Corridor Pipeline transport system. A long term off-take agreement is in place with Shell to purchase Vacuum Gas Oil at market rates as well as agreements to sell volumes of Premium Albian Synthetic and Albian Heavy Synthetic from the Scotford Upgrader at market rates.

Gross design capacity of the combined AOSP mines is 280,000 bbl/d of bitumen (196,000 bbl/d net). Shell obtained the Joint Review Panel Approval along with other associated approvals in 2013 for a 100,000 bbl/d expansion of the Jackpine Mine and is subject to several additional auxiliary approvals.

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 40 years and has developed a significant database, extensive operating experience and an experienced staff. In 2017, the Company produced from 10 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 also has a 73.5% working interest in the Strathspey field. In addition, the Company also has an interest in 6 licences covering 9 blocks and part blocks surrounding the Ninian platform 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.

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.

The decommissioning activities at the Murchison platform commenced in the fourth quarter of 2013 and cessation of production occurred in the first quarter of 2014. The decommissioning activities are targeted to be completed in approximately two years.

Due to the Company’s continued focus on proactive capital allocation and lowering overall operating and capital cost structures, the Company commenced abandonment of the Ninian North Platform in the second quarter of 2017. The decommissioning activities are targeted to be completed in approximately six years.

Offshore Africa

Côte d'Ivoire

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

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

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.

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. The Company has no further development activities currently planned for 2018.

South Africa

In May 2012 the Company completed the conversion of its 100% owned oil 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 for net cash consideration of US$255 million. In the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery. In 2014, the exploration well drilled on Block 11B/12B was suspended due to mechanical issues with marine equipment on the drilling rig. The rig safely left the well location and, as the available drilling window had ended, it was demobilized by the operator. The South African authorities have formally confirmed the well drilled satisfies the work obligation for the initial period of the Block 11B/12B Exploration Right. The operator plans to re-enter the well in late 2018 or early 2019.

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, 2017.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	29,201.0	23,669.4	11,916.0	10,538.4	41,117.0	34,207.8
British Columbia	2,163.0	1,880.3	247.0	223.0	2,410.0	2,103.3
Saskatchewan	10,655.0	9,761.1	2,829.0	1,728.3	13,484.0	11,489.4
Manitoba	—	—	214.0	209.5	214.0	209.5
Total Canada	42,019.0	35,310.8	15,206.0	12,699.2	57,225.0	48,010.0
United States Louisiana	—	—	2.0	0.3	2.0	0.3
North Sea UK Sector	2.0	1.5	55.0	48.1	57.0	49.6
Offshore Africa						
Côte d'Ivoire	—	—	24.0	14.0	24.0	14.0
Gabon	—	—	11.0	10.2	11.0	10.2
Total	42,021.0	35,312.3	15,298.0	12,771.8	57,319.0	48,084.1

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, 2017.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Non-Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	7,657.0	5,944.6	9,535.0	8,255.7	17,192.0	14,200.3
British Columbia	2,245.0	1,874.5	545.0	459.3	2,790.0	2,333.8
Saskatchewan	2,467.0	2,312.3	3,555.0	2,808.0	6,022.0	5,120.3
Manitoba	—	—	29.0	27.1	29.0	27.1
Northwest Territories	69.0	17.3	—	—	69.0	17.3
Total Canada	12,438.0	10,148.7	13,664.0	11,550.1	26,102.0	21,698.8
United States Louisiana	—	—	2.0	0.3	2.0	0.3
North Sea UK Sector	2.0	1.5	25.0	22.7	27.0	24.2
Offshore Africa						
Côte d'Ivoire	—	—	12.0	6.9	12.0	6.9
Gabon	—	—	2.0	1.9	2.0	1.9
Total	12,440.0	10,150.2	13,705.0	11,581.9	26,145.0	21,732.1

Principal Documents Exhibits

Properties With Attributed and No Attributed Reserves

The following table summarizes the Company's landholdings as at December 31, 2017.

	Proved Properties		Unproved Properties		Total Acreage		Average Working Interest	
Region (thousands of acres)	Gross	Net	Gross	Net	Gross	Net	%	
North America								
Northeast British Columbia	1,210	1,040	4,573	3,863	5,783	4,903	85	%
Northwest Alberta	1,923	1,427	3,381	2,596	5,304	4,023	76	%
Northern Plains	2,206	1,879	8,168	7,075	10,374	8,954	86	%
Southern Plains	2,902	2,476	3,229	2,777	6,131	5,253	86	%
Southeast Saskatchewan	121	110	122	113	243	223	92	%
Thermal In Situ Oil Sands	96	96	1,555	1,342	1,651	1,438	87	%
Oil Sands Mining & Upgrading	58	48	194	181	252	229	91	%
Non-core Regions	9	4	1,148	426	1,157	430	37	%
Fee Title	93	92	853	848	946	940	99	%
North America Total	8,618	7,172	23,223	19,221	31,841	26,393	83	%
International								
North Sea UK Sector	63	55	80	72	143	127	89	%
Offshore Africa								
Côte d'Ivoire	10	6	91	53	101	59	58	%
Gabon	—	—	152	140	152	140	92	%
South Africa	—	—	4,002	2,001	4,002	2,001	50	%
International Total	73	61	4,325	2,266	4,398	2,327	53	%
Company Total	8,691	7,233	27,548	21,487	36,239	28,720	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 0.6 million net acres attributed to the North America properties which are currently expected to expire by December 31, 2018.

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.

2017 Costs Incurred in Crude Oil, Natural Gas and NGLs Activities

MM$	North America	North Sea	Offshore Africa	Total
Property Acquisitions				
Proved	15,091	—	—	15,091
Unproved	321	—	—	321
Exploration	112	—	15	127
Development	3,753	255	101	4,109
Less: Net non-cash and other costs (1)	(2,785)	(95)	(12)	(2,892)
Costs Incurred	16,492	160	104	16,756

(1) Non-cash and other costs are comprised primarily of changes in ARO, proceeds on disposition of properties in excess of original cost, and certain purchase accounting adjustments on AOSP.

Exploration and Development Activities

Set forth below are summaries of crude oil, natural gas and NGLs drilling activities completed by the Company for the fiscal year ended December 31, 2017 by geographic region along with a general discussion of 2018 activity.

		2017 Exploratory Wells					
		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
North America							
Northeast British Columbia	Gross	—	—	—	—	—	—
	Net	—	—	—	—	—	—
Northwest Alberta	Gross	1.0	4.0	1.0	—	—	6.0
	Net	1.0	2.6	1.0	—	—	4.6
Northern Plains	Gross	17.0	1.0	—	—	—	18.0
	Net	16.0	1.0	—	—	—	17.0
Southern Plains	Gross	1.0	—	—	—	—	1.0
	Net	1.0	—	—	—	—	1.0
Southeast Saskatchewan	Gross	—	—	—	—	—	—
	Net	—	—	—	—	—	—
Oil Sands Mining and Upgrading	Gross	—	—	—	—	—	—
	Net	—	—	—	—	—	—
Non-core Regions	Gross	—	—	—	—	—	—
	Net	—	—	—	—	—	—
North America Total	Gross	19.0	5.0	1.0	—	—	25.0
	Net	18.0	3.6	1.0	—	—	22.6
North Sea UK Sector	Gross	—	—	—	—	—	—
	Net	—	—	—	—	—	—
Offshore Africa	Gross	—	—	—	—	—	—
	Net	—	—	—	—	—	—
Company Total	Gross	19.0	5.0	1.0	—	—	25.0
	Net	18.0	3.6	1.0	—	—	22.6

Principal Documents Exhibits

		2017 Development Wells					
		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
North America							
Northeast British Columbia	Gross	1.0	7.0	—	—	—	8.0
	Net	1.0	7.0	—	—	—	8.0
Northwest Alberta	Gross	25.0	15.0	—	—	—	40.0
	Net	18.3	10.3	—	—	—	28.6
Northern Plains	Gross	465.0	—	5.0	17.0	43.0	530.0
	Net	440.2	—	4.9	17.0	43.0	505.1
Southern Plains	Gross	6.0	—	1.0	1.0	—	8.0
	Net	6.0	—	1.0	1.0	—	8.0
Southeast Saskatchewan	Gross	11.0	—	—	1.0	—	12.0
	Net	9.6	—	—	1.0	—	10.6
Oil Sands Mining and Upgrading	Gross	—	—	—	15.0	210.0	225.0
	Net	—	—	—	15.0	210.0	225.0
Non-core Regions	Gross	—	—	—	—	—	—
	Net	—	—	—	—	—	—
North America Total	Gross	508.0	22.0	6.0	34.0	253.0	823.0
	Net	475.1	17.3	5.9	34.0	253.0	785.3
North Sea UK Sector	Gross	2.0	—	—	2.0	—	4.0
	Net	1.8	—	—	1.8	—	3.6
Offshore Africa	Gross	—	—	—	—	—	—
	Net	—	—	—	—	—	—
Company Total	Gross	510.0	22.0	6.0	36.0	253.0	827.0
	Net	476.9	17.3	5.9	35.8	253.0	788.9

Total success rate for 2017, excluding service and stratigraphic test wells, was 99%.

2018 Activity

Capital expenditures in 2018 are currently targeted to be as follows:

(MM$)	2018
Exploration and Production	
North America natural gas and NGLs	$440
North America crude oil	1,115
International crude oil	410
Thermal In Situ Oil Sands	960
Net acquisitions, midstream and other	30
Total Exploration and Production	$2,955
Oil Sands Mining and Upgrading	
Environment, technology and project development	500
Sustaining capital	660
Turnarounds, reclamation and other	220
Total Oil Sands Mining and Upgrading	$1,380
Total	$4,335

The Company targets to drill the following wells in Exploration and Production for 2018:

- approximately 67 net producing wells in its North America light and medium crude oil operations;
- approximately 22 net producing wells at Pelican Lake;
- approximately 377 net producing wells in its primary heavy crude oil operations;
- approximately 17 net producing wells in its North America natural gas operations;
- approximately 119 net producing thermal wells including 64 net producing wells at Primrose, 49 net producing wells at Kirby North and 6 net producing wells at Kirby South; and
- 4.6 net producing wells in the North Sea and 1.7 net producing wells at the Baobab field in Côte d'Ivoire.

Production Estimates

The following table illustrates Canadian Natural's estimated 2018 company gross daily proved and probable production reflected in the reserves reports as of December 31, 2017 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	50,855	100,491	69,526	112,889	368,220	1,480	39,894	988,542
North Sea	23,797	—	—	—	—	35	—	29,630
Offshore Africa	16,748	—	—	—	—	23	—	20,581
Total Proved	91,400	100,491	69,526	112,889	368,220	1,538	39,894	1,038,753
PROBABLE								
North America	4,668	8,529	2,323	29	31,168	91	3,735	65,619
North Sea	2,825	—	—	—	—	4	—	3,491
Offshore Africa	2,342	—	—	—	—	4	—	3,009
Total Probable	9,835	8,529	2,323	29	31,168	99	3,735	72,119

Principal Documents Exhibits

Production History

	2017				
	Q1	Q2	Q3	Q4	Year Ended
North America Production and Netbacks by Product (1)					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	49,490	50,770	52,959	52,657	51,481
Netbacks ($/bbl)					
Sales price (2)	$58.42	$57.44	$53.04	$64.26	$58.30
Transportation	3.13	3.53	3.36	3.34	3.34
Royalties	7.69	8.24	6.54	7.13	7.38
Production expenses	19.21	19.51	19.77	20.97	19.88
Netback	$28.39	$26.16	$23.37	$32.82	$27.70
Primary Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	94,803	89,345	98,564	99,325	95,530
Netbacks ($/bbl)					
Sales price (2)	$45.22	$45.92	$45.55	$50.71	$46.88
Transportation	3.78	4.34	3.99	4.18	4.07
Royalties	4.98	4.34	5.71	5.84	5.24
Production expenses	14.55	16.86	15.19	16.28	15.71
Netback	$21.91	$20.38	$20.66	$24.41	$21.86
Pelican Lake Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	46,617	46,932	47,604	65,654	51,743
Netbacks ($/bbl)					
Sales price (2)	$45.82	$47.64	$45.67	$52.44	$48.30
Transportation	3.21	4.36	3.96	4.15	3.94
Royalties	8.06	7.20	7.84	9.68	8.33
Production expenses	6.37	6.38	6.00	6.81	6.42
Netback	$28.18	$29.70	$27.87	$31.80	$29.61
Bitumen (Thermal Oil)					
Average daily production (before royalties) (bbl/d)	128,372	105,719	122,372	124,121	120,140
Netbacks ($/bbl)					
Sales price (2)	$40.69	$41.15	$41.38	$46.58	$42.49
Transportation	2.11	2.61	2.50	2.30	2.37
Royalties	4.01	3.56	5.66	4.94	4.57
Production expenses	11.55	14.15	10.25	11.65	11.81
Netback	$23.02	$20.83	$22.97	$27.69	$23.74
SCO					
Average daily production (before royalties) (bbl/d) (3)	192,491	257,541	354,365	321,496	282,026
Netbacks ($/bbl)					
Sales price (2)	$67.85	$63.39	$56.55	$70.85	$63.98
Transportation	1.17	1.32	1.61	1.88	1.54
Royalties (4)	1.14	1.38	1.39	2.45	1.64
Production expenses (5)	22.08	23.44	22.69	24.99	23.40
Netback	$43.46	$37.25	$30.86	$41.53	$37.40
Natural Gas					
Average daily production (before royalties) (MMcf/d)	1,613	1,603	1,593	1,596	1,601
Netbacks ($/Mcf)					
Sales price (2)	$3.08	$2.84	$2.07	$2.33	$2.58

Transportation	0.39	0.31	0.31	0.45	0.37
Royalties	0.18	0.12	0.05	0.07	0.11
Production expenses	1.20	1.17	1.15	1.26	1.19
Netback	$ 1.31	$ 1.24	$ 0.56	$ 0.55	$ 0.91

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Production History

	2017				
	Q1	Q2	Q3	Q4	Year Ended
Natural Gas Liquids					
Average daily production (before royalties) (bbl/d)	40,682	40,036	39,717	41,780	40,555
Netbacks ($/bbl)					
Sales price (2)	$33.36	$32.51	$30.31	$41.23	$34.44
Transportation	1.95	1.99	1.88	1.70	1.88
Royalties	5.31	5.22	3.37	4.17	4.51
Production expenses	7.05	6.97	7.39	7.47	7.22
Netback	$19.05	$18.33	$17.67	$27.89	$20.83
North Sea Production and Netbacks by Product (1)					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	23,042	26,304	24,832	19,548	23,426
Netbacks ($/bbl)					
Sales price (2)	$70.03	$64.37	$66.07	$76.71	$69.43
Transportation	0.97	0.51	0.96	0.51	0.75
Royalties	0.13	0.14	0.13	0.12	0.13
Production expenses	36.86	28.86	35.72	44.37	36.60
Netback	$32.07	$34.86	$29.26	$31.71	$31.95
Natural Gas					
Average daily production (before royalties) (bbl/d)	37	37	46	37	39
Netbacks ($/bbl)					
Sales price (2)	$8.68	$6.89	$7.73	$9.77	$8.24
Transportation	2.38	2.05	1.16	1.16	1.66
Royalties	—	—	—	—	—
Production expenses	3.07	3.40	3.09	3.98	3.37
Netback	$3.23	$1.44	$3.48	$4.63	$3.21
Offshore Africa Production and Netbacks by Product (1)					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	22,616	20,480	18,776	19,519	20,335
Netbacks ($/bbl)					
Sales price (2)	$61.95	$69.93	$64.14	$73.43	$67.15
Transportation	—	—	—	—	—
Royalties	2.50	4.26	3.56	6.15	4.13
Production expenses	18.54	32.39	29.24	17.96	24.07
Netback	$40.91	$33.28	$31.34	$49.32	$38.95
Natural Gas					
Average daily production (before royalties) (bbl/d) (3)	23	16	25	23	22
Netbacks ($/bbl)					
Sales price (2)	$6.23	$6.84	$6.56	$6.73	$6.57
Transportation	0.18	0.18	0.17	0.17	0.17
Royalties	0.63	0.51	0.95	0.84	0.76
Production expenses	3.50	3.88	2.32	2.26	2.90
Netback	$1.92	$2.27	$3.12	$3.46	$2.74

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities. SCO sales price is also net of feedstock costs.
(3)

2017 SCO production before royalties excludes 651 bbl/d of SCO consumed internally as diesel.

(4) Calculated based on bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

(5) Adjusted cash production costs on a per unit basis are based on sales volumes excluding turnaround periods.

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SELECTED FINANCIAL INFORMATION

(MM$, except per common share information)	Year Ended December 31 2017	2016
Product sales	$17,669	$11,098
Net earnings (loss)	$2,397	$(204)
Per common share – basic	$2.04	$(0.19)
– diluted	$2.03	$(0.19)
Adjusted net earnings (loss) from operations (1)	$1,403	$(669)
Per common share – basic	$1.19	$(0.61)
– diluted	$1.19	$(0.61)
Funds flow from operations (1)	$7,347	$4,293
Per common share – basic	$6.25	$3.90
– diluted	$6.21	$3.89
Dividends declared per common share	$1.10	$0.94
Total assets	$73,867	$58,648
Total long-term liabilities	$35,953	$27,289
Net capital expenditures	$17,129	$3,794

(1) The derivation of these non-GAAP measures are discussed in the section "Net Earnings (Loss) and Funds Flow from Operations" of the Company's MD&A for the year ended December 31, 2017 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 in each of its last three years ended December 31.

	2017	2016 (1)	2015 (1)
Cash dividends declared per common share	$1.10	$0.94	$0.92

(1) On December 31, 2015, the Company paid the dividend it would historically have paid on January 1st of the following year. As a result, the actual dividends paid in 2015 were $1.145 per common share and the actual dividends paid in 2016 were $0.69 per common share.

Note: On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share, beginning with the dividend payable of April 1, 2018.

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 determine, 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 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 AIF.

	Senior Unsecured Debt Securities	Commercial Paper	Outlook/Trend [1]
Moody’s Investors Service, Inc. (“Moody’s”)[2]	Baa3	P-3	Stable
S&P Global Ratings (“S&P”)[2]	BBB+	A-2	Negative
DBRS Limited (“DBRS”)[2]	BBB (high)	—	Stable

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

(2) Following the announced acquisition of a significant interest in the AOSP and certain other producing and non-producing oil and gas properties, Moody’s affirmed the Company’s ratings and outlook, S&P placed the Company on CreditWatch with negative implications and affirmed its A-2 short-term and commercial paper ratings, and DBRS place the Company Under Review with Developing Implications. Subsequently, S&P affirmed its ratings and changed its outlook from Stable to Negative in May 2017 and DBRS affirmed its ratings and trend in June 2017.

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 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. A negative, positive or developing outlook indicates a higher likelihood of a rating change 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-3 by Moody’s indicates an acceptable 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 obligation. 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, typically six months to two years. A “Stable” outlook indicates that a rating is not likely to change during that time period. In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions however an outlook is not necessarily a precursor of a rating change or future CreditWatch action. 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

indicates that the obligor is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in the highest rating category, 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 absence of either a "(high)" or "(low)" designation indicates the rating is in the middle of the category. The rating trend is DBRS' opinion regarding the outlook for the rating in question, with rating trends falling into one of three categories – "Positive", "Stable", or "Negative". The rating trend indicates the direction in which DBRS considers the rating may move if present circumstances continue, or in certain cases, unless challenges are addressed.

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 not made any other payments to the credit rating organizations in the last two years.

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 2017.

	2017 Monthly Historical Trading on TSX			
Month	High	Low	Close	Volume Traded
January	$44.13	$38.66	$39.34	53,214,943
February	$40.50	$37.34	$38.09	44,314,632
March	$44.84	$38.17	$43.54	78,689,303
April	$45.94	$43.00	$43.48	34,671,402
May	$44.12	$38.65	$38.94	47,676,900
June	$40.45	$36.44	$37.42	60,332,183
July	$38.87	$35.90	$38.13	47,923,869
August	$41.10	$37.31	$38.47	48,156,112
September	$42.88	$38.17	$41.79	48,772,134
October	$45.44	$40.62	$45.02	39,306,762
November	$47.00	$42.38	$43.76	47,969,325
December	$45.18	$42.54	$44.92	37,394,740

On May 16, 2017, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the TSX, alternative Canadian trading platforms, and the NYSE, up to 27,931,135 common shares over a 12 month period commencing on May 23, 2017 and ending May 22, 2018. During 2017, the Company did not purchase any common shares for cancellation. On March 14, 2018, the Board of Directors approved the Company's application for a Normal Course Issuer Bid to purchase through the facilities of the TSX, alternative Canadian trading platforms, and the NYSE, up to 5% of its issued and outstanding common shares (which on March 14, 2018 equaled 61,295,086 common shares) over a 12 month period commencing on or after May 22, 2018 and subject to applicable regulatory and other approvals.

Principal Documents Exhibits

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 five 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 14, 2018 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 64)	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, Badger Daylighting Ltd. 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 the Calgary Stampede Foundation.
N. Murray Edwards, O.C. London, England	Executive Chairman and Director (5) (age 58)	Corporate director and investor. He has served continuously as a director of the Company since September 1988. Prior to December 2015, he was President of Edco Financial Holdings Ltd. (private management and consulting company). Currently, he is Chairman and serving on the board of directors of Ensign Energy Services Inc. and Magellan Aerospace Corporation.
Timothy W. Faithfull London, England	Director (1)(3) (age 73)	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. He is currently serving on the board of directors of TransAlta Corporation and ICE Futures Europe.
Honourable Gary A. Filmon, P.C., O.C., O.M. Winnipeg, Manitoba Canada	Director (1)(4) (age 75)	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 Arctic Glacier Income Trust and Exchange Income Corporation. Mr. Filmon will not be standing for re-election at the Annual General Meeting of Shareholders of the Company to be held on May 3, 2018.
Christopher L. Fong Calgary, Alberta Canada	Director (3)(5) (age 68)	Corporate director. He has served continuously as a director of the Company since November 2010. He is currently serving on the board of directors of Computer Modelling Group Ltd.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Ambassador Gordon D. Giffin Atlanta, Georgia U.S.A	Director (1)(4) (age 68)	Partner, Dentons US LLP (law firm); prior thereto Senior Partner, McKenna Long & Aldridge LLP (law firm) from May 2001 until its merger with Dentons in 2015. 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, and TransAlta Corporation.
Wilfred A. Gobert Calgary, Alberta Canada	Director (2)(4)(5) (age 70)	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 and Paramount Resources Ltd.
Steve W. Laut Calgary, Alberta Canada	Executive Vice Chairman and Director (3) (age 60)	Officer of the Company. He has served continuously as a director of the Company since August 2006.
Tim S. McKay Calgary, Alberta Canada	President and Director (age 57)	Officer of the Company. He was appointed as a director of the Company on February 27, 2018.
Honourable Frank J. McKenna P.C., O.C., O.N.B., Q.C. Cap Pelé, New Brunswick Canada	Director (2)(4) (age 70)	Deputy Chair, TD Bank Group. 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.
David A. Tuer Calgary, Alberta Canada	Director (1)(5) (age 68)	Chairman, Optiom Inc. (private insurance company); prior thereto, from 2010 to 2015, the 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. from 2008 to 2010. He has served continuously as a director of the Company since May 2002.
Annette M. Verschuren, O.C. Toronto, Ontario Canada	Director (2)(3) (age 61)	Chair and Chief Executive Officer of NRStor Inc., an energy storage project developer of energy storage technologies. She has served as a director of the Corporation since November 2014. She currently serves as Chancellor of Cape Breton University and as a director of Liberty Mutual Insurance Group and a board member of numerous non-profit organizations. Currently serving on the board of directors of Air Canada and Saputo Inc.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Troy J.P. Andersen Calgary, Alberta Canada	Senior Vice-President, Canadian Conventional Field Operations (age 39)	Officer of the Company since January 2015; prior thereto Production Manager from July 2011 to October 2013, Northern Operations Manager from October 2013 to January 2015 and most recently Vice-President, West Conventional Operations from January 2015 to May 2017.
Jeffrey J. Bergeson Calgary, Alberta Canada	Vice-President, Exploitation East (age 61)	Officer of the Company.
Corey B. Bieber Calgary, Alberta Canada	Chief Financial Officer and Senior Vice-President, Finance (age 54)	Officer of the Company.
Bryan C. Bradley Calgary, Alberta Canada	Vice-President, Marketing (age 52)	Officer of the Company.
Alexander R. Carter Calgary, Alberta Canada	Vice-President, Exploration West (age 59)	Officer of the Company since July, 2017; prior thereto Exploration Manager Deep Basin Region for Devon Canada Corporation from January 2013 to March 2014 and most recently Exploration Manager Deep Basin South from April 2014 to July 2017.
Trevor J. Cassidy Calgary, Alberta Canada	Senior Vice-President, Thermal (age 44)	Officer of the Company since August 2014; prior thereto Production Manager from April 2005 to August 2014 and most recently Vice-President, Production Central from August 2014 to December 2017.
Mark S. Chalmers Calgary, Alberta Canada	Vice-President, Exploration Central (age 58)	Officer of the Company since January 2015; prior thereto Exploration Manager, Northern Plains from September 2010 to January 2015.
William R. Clapperton Calgary, Alberta Canada	Vice-President, Regulatory, Stakeholder and Environmental Affairs (age 55)	Officer of the Company.
Réal M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 67)	Officer of the Company.

Principal Documents Exhibits

Name	Position Presently Held	Principal Occupation During Past 5 Years
Darren M. Fichter Calgary, Alberta Canada	Chief Operating Officer, Exploration and Production (age 47)	Officer of the Company.
Allan E. Frankiw Calgary, Alberta Canada	Senior Vice-President, Production (age 61)	Officer of the Company.
Jay E. Froc Calgary, Alberta Canada	Senior Vice-President, Oil Sands Mining and Upgrading (age 52)	Officer of the Company since September 2013. Held various positions with Suncor Energy Inc. from 2003 to September 2013 and most recently Vice-President, Infrastructure, Logistics and Project Controls with the Company from September 2013 to December 2017.
Christopher I. Grayston Calgary, Alberta Canada	Vice-President, Finance and E&P Accounting (age 58)	Officer of the Company since May 2015; prior thereto Assistant Controller, Operations Accounting from November 2010 to March 2014 and most recently Controller, Operations Accounting from March 2014 to May 2015.
Dean W. Halewich Calgary, Alberta Canada	Vice-President, Thermal Projects (age 50)	Officer of the Company.
Jon E. Halford Calgary, Alberta Canada	Vice-President, Human Resources (age 44)	Officer of the Company since January 2015; prior thereto Manager, Materials and Contracts from June 2010 to October 2010, Director, Supply Management - Major Projects from October 2010 to January 2015 and most recently Vice-President, Commercial Operations from January 2015 to May 2017.
Ken A. Harke St. Albert, Alberta Canada	Vice-President, West Field Operations (age 51)	Officer of the Company since April 2016; prior thereto Area Superintendent, St. Albert and Edson, Alberta from January 2003 to April 2014, Manager, Operations North Central Alberta from April 2014 to April 2016 and most recently Vice-President, Thermal and East Conventional Operations from April 2016 to May 2017.
Murray G. Harris Calgary, Alberta Canada	Vice-President, Financial Controller and Horizon Accounting (age 54)	Officer of the Company.

Principal Documents Exhibits

Name	Position Presently Held	Principal Occupation During Past 5 Years
David B. Holt Calgary, Alberta Canada	Vice-President, Production, West (age 52)	Officer of the Company.
Gerard Iannattone Calgary, Alberta Canada	Vice-President, Thermal Exploitation Athabasca (age 58)	Officer of the Company since March 2014; prior thereto Exploitation Manager, N.E. British Columbia from November 2006 to March 2014.
Kenneth W. Imlach Calgary, Alberta Canada	Vice-President, Production East (age 40)	Officer of the Company since May 2017; prior thereto Production Manager, Kirby South from January 2012 to November 2016 and most recently Production Manager, Deep Basin South from November 2016 to May 2017.
Brent F. Kondratowicz Calgary, Alberta Canada	Vice-President, Central, Production (age 36)	Officer of the Company since January 2018; prior thereto Production Engineer, S.E. Saskatchewan and Manitoba from April 2012 to September 2013, Production Manager N.E. Gas from September 2013 to August 2014 and most recently Production Manager, Brintnell from August 2014 to December 2017.
Vladimir Kostic Calgary, Alberta Canada	Vice-President, East, Field Operations (age 47)	Officer of the Company since May 2017; prior thereto Production Manager, Heavy Oil North from January 2013 to August 2014 and most recently Manager, Eastern Field Operations from August 2014 to May 2017.
Kevin B. Kowbel Calgary, Alberta Canada	Vice-President, Drilling and Completions (age 47)	Officer of the Company.
Trevor D. Krause Calgary, Alberta Canada	Vice-President, Exploration, East (age 46)	Officer of the Company since January 2015; prior thereto Exploration Manager, N.E. Alberta from April 2007 to July 2011 and most recently Exploration Manager, Heavy Oil South from July 2011 to January 2015.
Ronald K. Laing Calgary, Alberta Canada	Senior Vice-President, Corporate Development, Land and Human Resources (age 48)	Officer of the Company.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Raul A. Lanfranchi Calgary, Alberta Canada	Vice-President, Downstream Projects (age 60)	Officer of the Company since February 2016; prior thereto Project Manager, Horizon from July 2006 to March 2013, Project Director, Horizon Downstream from April 2013 to January 2016.
Ken G. MacKenzie Calgary, Alberta Canada	Vice-President, Mining, Horizon (age 52)	Officer of the Company since July 2016; prior thereto Director, Mine Technical Services from November 2011 to June 2016.
Pamela A. McIntyre Calgary, Alberta Canada	Vice-President, Safety and Asset Integrity (age 55)	Officer of the Company
Casey D. McWhan Calgary, Alberta Canada	Vice-President, Horizon Bitumen Production (age 55)	Officer of the Company.
Kevin W. Melnyk Calgary, Alberta Canada	Vice-President, Upgrading and Utilities (age 51)	Officer of the Company since November 2015; prior thereto, Agrium Plant Manager, Redwater Nitrogen Operations 2012-2015 and most recently Director, Utilities and Upgrading from January 2015 to October 2015 of the Company.
Paul M. Mendes Calgary, Alberta Canada	Vice-President, Legal, General Counsel and Corporate Secretary (age 52)	Officer of the Company.
Shawn M. Neilson Calgary, Alberta Canada	Vice-President, Mining, Albian Sands (age 54)	Vice-President since June 2017; prior thereto held various positions with Shell Canada Ltd. regarding the Albian and Muskeg River mines.
S. John Parr Calgary, Alberta Canada	Vice-President, Conventional Facilities and Pipelines (age 57)	Officer of the Company.
David A. Payne Calgary, Alberta Canada	Vice-President, Exploitation, West (age 56)	Officer of the Company.

William R. Peterson Calgary, Alberta Canada	Senior Vice-President, Development Operations (age 51)	Officer of the Company.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Andrew T. Richardson Calgary, Alberta Canada	Vice-President, Thermal Production, Athabasca (age 50)	Officer of the Company since March 2014; prior thereto Manager CSS Production with the Company from January 2012 to November 2012 and most recently Manager, Wolf Lake and Production Development from December 2012 to March 2014.
Joy P. Romero Calgary, Alberta Canada	Vice-President, Technology and Innovation (age 61)	Officer of the Company.
Sheldon L. Schroeder Fort McMurray, Alberta Canada	Vice-President, Upstream Projects Infrastructure, Logistics & Project Controls (age 50)	Officer of the Company.
Michael S. Skipper Calgary, Alberta Canada	Vice-President, Exploitation, Central (age 41)	Officer of the Company since March 3, 2017; prior thereto Heavy Oil South Exploitation Manager from February 2012 to February 2016 and most recently Brintnell Exploitation Manager from February 2016 to March 2017.
Kara L. Slemko Calgary, Alberta Canada	Vice-President, Commercial Operations (age 48)	Officer of the Company since January 2015; prior thereto Director, Supply Management, Operations with the Company from September 2012 to January 2015 and most recently Vice-President, Supply Management from January 2015 to May 2017.
Kendall W. Stagg Calgary, Alberta Canada	Senior Vice-President, Exploration (age 56)	Officer of the Company.
Scott G. Stauth Calgary, Alberta Canada	Chief Operating Officer, Oil Sands (age 52)	Officer of the Company.
Stephen C. Suche Calgary, Alberta Canada	Vice-President, Information and Corporate Services (age 58)	Officer of the Company.
Domenic Torriero Calgary, Alberta Canada	Vice-President, Thermal Exploration (age 53)	Officer of the Company.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Betty Yee Calgary, Alberta Canada	Vice-President, Land (age 53)	Officer of the Company since June 2013; prior thereto Manager of Acquisition and Divestments from July 2003 to June 2013.
Daryl G. Youck Calgary, Alberta Canada	Vice-President, Thermal Exploitation Primrose (age 49)	Officer of the Company.
Robin S. Zabek Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 46)	Officer of the Company since March 2014; prior thereto Manager Exploitation from September 2006 to March 2014.

(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Health, Safety, Asset Integrity 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 General Meeting of Shareholders held on May 4, 2017 with the exception of Tim McKay who was appointed by the Board of Directors effective February 27, 2018.

As at December 31, 2017, the directors and executive officers of the Company, as a group, beneficially owned or controlled or directed, directly or indirectly, in the aggregate, approximately 28 million common shares (approximately 2%) of the total outstanding common shares of 1,223 million (approximately 3% 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 in 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.

During the year ended December 31, 2017, there were no penalties or sanctions imposed against the Company by a court of competent jurisdiction or other regulatory body relating to securities legislation or by a securities regulatory authority and the Company has not entered into any settlement agreements before a court of competent jurisdiction or other regulatory body relating to securities legislation or with a securities regulatory authority.

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

In addition to contracts entered into in the ordinary course of business, concurrently with the closing of the AOSP acquisition, Canadian Natural, Shell Canada Energy ("SCE"), Shell Canada Resources ("SCR") and Shell Gas B.V. ("SG") entered into a registration rights agreement (the "Registration Rights Agreement"), which provides SCE, SCR, SG and any transferees to whom their rights have been transferred in accordance with the Registration Rights Agreement (the "Holders") with certain rights in respect of the 97,560,975 common shares originally held or other securities of Canadian Natural received by the Holders as a result of a dividend, distribution, exchange, share split, recapitalization or other corporate event in respect of the common shares (collectively, the "Registrable Securities").

Pursuant to the Registration Rights Agreement, the Company filed a short form base shelf prospectus with applicable Canadian regulatory authorities and a registration statement on Form F-10 with the SEC allowing for the distribution of up to 97,560,975 common shares of the Company.

Subject to certain limits, qualifications and applicable blackout periods, the Registration Rights Agreement provides the Holders with the right, terminating on the date on which the Holders hold in aggregate less than 0.75% of the common shares issued and outstanding (the "Qualification Period"), to effect an offering by the Holders of all or part of their Registrable Securities included in the applicable base shelf prospectus or registration statement.

In addition, if during the Qualification Period Canadian Natural proposes to file a prospectus, prospectus supplement or registration statement in Canada and/or the U.S. with respect to common shares or any securities convertible into, or exchangeable or exercisable for, common shares, then subject to certain limits and qualifications, Canadian Natural will be required to provide written notice to the Holders of its intention to do so. Subject to certain limits and qualifications, Canadian Natural is required to use reasonable efforts to include in the proposed distribution such number of Registrable Securities as the Holders shall request on the same terms and conditions as Canadian Natural's proposed distribution.

The Holders may transfer the registration rights provided for under the Registration Rights Agreement to their affiliates and, in connection with transfers of at least 32,195,121 common shares, to certain registered brokers or dealers on notice to Canadian Natural where the transferee also agrees to be bound by the Registration Rights Agreement.

A copy of the full text of the Registration Rights Agreement has been filed on SEDAR and EDGAR.

INTERESTS OF EXPERTS

The Company's independent auditors are PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have issued an independent auditor's report dated February 28, 2018 in respect of the Company's consolidated financial statements as at December 31, 2017 and December 31, 2016 and for each of the three years in the period ended December 31, 2017 and the Company's internal control over financial reporting as at December 31, 2017. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct with Guidance of the Chartered Professional Accountants of Alberta and the rules of the US Securities and Exchange Commission.

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

Ms. C. M. Best is a chartered accountant with over 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 degree 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 2017 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 as set out in "Audit fees" in the table below; (ii) audit related services including pension assets, Crown Royalty Statements and in respect of the AOSP acquisition as set out in "Audit related fees" in the table below; (iii) tax services related to expatriate personal tax and compliance and other corporate tax return matters as set out in "Tax fees" in the table below; and (iv) non-audit services related to expatriate visa application assistance and to accessing resource materials through PwC’s accounting literature library as set out in "All other fees" in the table below.

Auditor service (000’s)	2017	2016
Audit fees	$2,960	$2,512
Audit related fees	574	246
Tax fees	470	410
All other fees	52	62
Total	$4,056	$3,230

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

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 14, 2018 in connection with the Annual General Meeting of Shareholders of Canadian Natural to be held on May 3, 2018 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, 2017 found on pages 20 to 55, 56 to 95 and 96 to 105 respectively, of the 2017 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:
2100, 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 "Company"):

1. We have evaluated and reviewed the Company's reserves data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation and review.
3. We carried out our evaluation and review in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. 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.
5. The following table shows the net present value of 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 Company evaluated and reviewed for the year ended December 31, 2017, and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the Company's management and board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation/Review Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate) ($ millions)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	December 31, 2017	Canada and USA	—	45,981	2,230	48,211
Sproule International Limited	December 31, 2017	United Kingdom and Offshore Africa	—	7,688	—	7,688
GLJ Petroleum Consultants Ltd.	December 31, 2017	Canada	—	41,437	17,129	58,566
Total			—	95,106	19,359	114,465

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

8. 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 referred to above:

Sproule Associates Limited
Calgary, Alberta, Canada,
February 28, 2018

Sproule International Limited
Calgary, Alberta, Canada,
February 28, 2018

Original Signed By
SIGNED "CAMERON P. SIX"
Cameron P. Six, P.Eng.
President and CEO

Original Signed By
SIGNED "CAMERON P. SIX"
Cameron P. Six, P.Eng.
President and CEO

Original Signed By
SIGNED "NORA T. STEWART"
Nora T. Stewart, P.Eng.
Senior Vice President, Reserves Certification

Original Signed By
SIGNED "SCOTT W. PENNELL"
Scott W. Pennell, P.Eng.
Senior Vice President, Engineering

Original Signed By
SIGNED "STEVEN J. GOLKO"
Steven J. Golko, P.Eng.
Vice President, New Ventures and Strategic Advisory

Original Signed By
SIGNED "ALEC KOVALTCHOUK"
Alec Kovaltchouk, P.Geo.
Vice President, Geoscience

Original Signed By
SIGNED "ALEC KOVALTCHOUK"
Alec Kovaltchouk, P.Geo.
Vice President, Geoscience

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada,
February 28, 2018

Original Signed By
SIGNED "TIM R. FREEBORN"
Tim R. Freeborn, P.Eng.
Vice President
Mineable Oil Sands and Shales

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 "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

Independent qualified reserves evaluators have evaluated and reviewed the Company'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 Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;
(b) met with 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 Company'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 Reserves Committee

Original Signed By

SIGNED "CHRISTOPHER L. FONG"
Christopher L. Fong
Independent Director and Member of the Reserves Committee

Dated this 28th day of February, 2018

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 Corporation's internal audit function, internal control of financial reporting programs, Sarbanes-Oxley Compliance program as well as the cybersecurity measures implemented in response to the Corporation's assessment of Cyber risk;
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, Governance and Risk 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 effect 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 review and consider management's assessment and report on the Corporation's cyber risk and cybersecurity measures implemented by the Corporation in response to those risks;

(g) 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.

(h) 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;

(i) 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;

(j) 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,

(k) 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.

AUDITED CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2017 AND 2016

Management's Report

The accompanying consolidated financial statements of Canadian Natural Resources Limited (the "Company") 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 as issued by the International Accounting Standards Board as 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 Professional 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, 2017; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2017.

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 and Senior Vice-President, Finance	Murray G. Harris, CA Vice-President, Financial Controller and Horizon Accounting

Calgary, Alberta, Canada
February 28, 2018

Management's Assessment of Internal Control over Financial Reporting

Management of Canadian Natural Resources Limited (the "Company") 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 (2013) 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, 2017. 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 Professional Accountants, has provided an opinion on the Company's internal control over financial reporting as at December 31, 2017, as stated in their accompanying Report of Independent Registered Public Accounting Firm.

(signed) "Steve W. Laut"	(signed) "Corey B. Bieber"
Steve W. Laut	Corey B. Bieber, CA
President	Chief Financial Officer and Senior Vice-President, Finance

Calgary, Alberta, Canada
February 28, 2018

Report of Independent Registered Public Accounting Firm
To the Shareholders and the Board of Directors of Canadian Natural Resources Limited

Opinions on the Financial Statements and Internal Control over Financial Reporting
We have audited the accompanying consolidated balance sheets of Canadian Natural Resources Limited (the "Company") as of December 31, 2017 and December 31, 2016, and the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").
In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and December 31, 2016 and its financial performance and its cash flows for each of the three years in the period ended December 31, 2017 in conformity with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB). Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.
Basis for Opinions
The Company's management is responsible for these consolidated financial statements, 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 Assessment of Internal Control Over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audits in accordance with the standards of the PCAOB. These standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.
Our audits of the consolidated financial statements included performing procedures to assess the risk of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provided a reasonable basis for our opinions.

Definition and Limitations 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 consolidated 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 consolidated financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorization 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 consolidated financial statements.

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.

SIGNED "PricewaterhouseCoopers LLP"

Chartered Professional Accountants
Calgary, Canada
February 28, 2018

We have served as the Company's auditor since 1973.

Principal Documents Exhibits

CONSOLIDATED BALANCE SHEETS

As at December 31 (millions of Canadian dollars)	Note	2017	2016
ASSETS			
Current assets			
Cash and cash equivalents		$137	$17
Accounts receivable		2,397	1,434
Current income taxes receivable		322	851
Inventory	4	894	689
Prepaids and other		175	149
Investments	8	893	913
Current portion of other long-term assets	9	79	283
		4,897	4,336
Exploration and evaluation assets	5	2,632	2,382
Property, plant and equipment	6	65,170	50,910
Other long-term assets	9	1,168	1,020
		$73,867	$58,648
LIABILITIES			
Current liabilities			
Accounts payable		$775	$595
Accrued liabilities		2,597	2,222
Current portion of long-term debt	10	1,877	1,812
Current portion of other long-term liabilities	11	1,012	463
		6,261	5,092
Long-term debt	10	20,581	14,993
Other long-term liabilities	11	4,397	3,223
Deferred income taxes	12	10,975	9,073
		42,214	32,381
SHAREHOLDERS' EQUITY			
Share capital	13	9,109	4,671
Retained earnings		22,612	21,526
Accumulated other comprehensive income (loss)	14	(68)	70
		31,653	26,267
		$73,867	$58,648

Commitments and contingencies (note 19).

Approved by the Board of Directors on February 28, 2018

(signed) "Catherine M. Best"	(signed) "N. Murray Edwards"
Catherine M. Best	N. Murray Edwards
Chair of the Audit Committee and Director	Executive Chairman of the Board of Directors and Director

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)
For the years ended December 31

(millions of Canadian dollars, except per common share amounts)	Note	2017	2016	2015
Product sales		$ 17,669	$ 11,098	$ 13,167
Less: royalties		(1,018)	(575)	(804)
Revenue		16,651	10,523	12,363
Expenses				
Production		5,596	4,099	4,726
Transportation, blending and feedstock		2,917	2,003	2,379
Depletion, depreciation and amortization	5, 6	5,186	4,858	5,483
Administration		319	345	390
Share-based compensation	11	134	355	(46)
Asset retirement obligation accretion	11	164	142	173
Interest and other financing expense	17	631	383	322
Risk management activities	18	35	33	(469)
Foreign exchange (gain) loss		(787)	(55)	761
Gain on acquisition, disposition and revaluation of properties	5, 6, 7	(379)	(250)	(739)
(Gain) loss from investments	8, 9	(38)	(327)	50
		13,778	11,586	13,030
Earnings (loss) before taxes		2,873	(1,063)	(667)
Current income tax recovery	12	(164)	(618)	(261)
Deferred income tax expense (recovery)	12	640	(241)	231
Net earnings (loss)		$ 2,397	$ (204)	$ (637)
Net earnings (loss) per common share				
Basic	16	$ 2.04	$ (0.19)	$ (0.58)
Diluted	16	$ 2.03	$ (0.19)	$ (0.58)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the years ended December 31

(millions of Canadian dollars)	2017	2016	2015
Net earnings (loss)	$ 2,397	$ (204)	$ (637)
Items that may be reclassified subsequently to net earnings (loss)			
Net change in derivative financial instruments designated as cash flow hedges			
Unrealized income (loss), net of taxes of $9 million (2016 – $3 million, 2015 – $2 million)	53	(18)	(23)
Reclassification to net earnings (loss), net of taxes of $5 million (2016 – $2 million, 2015 – $2 million)	(33)	(13)	(13)
	20	(31)	(36)
Foreign currency translation adjustment			
Translation of net investment	(158)	26	60
Other comprehensive income (loss), net of taxes	(138)	(5)	24
Comprehensive income (loss)	$ 2,259	$ (209)	$ (613)

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the years ended December 31

(millions of Canadian dollars)	Note	2017	2016	2015
Share capital	13			
Balance – beginning of year		$4,671	$4,541	$4,432
Issued for the acquisition of AOSP and other assets [(1)]	7, 13	3,818	—	—
Issued upon exercise of stock options		466	559	91
Previously recognized liability on stock options exercised for common shares		154	117	18
Return of capital on PrairieSky Royalty Ltd. share distribution	8	—	(546)	—
Balance – end of year		9,109	4,671	4,541
Retained earnings				
Balance – beginning of year		21,526	22,765	24,408
Net earnings (loss)		2,397	(204)	(637)
Dividends on common shares	13	(1,311)	(1,035)	(1,006)
Balance – end of year		22,612	21,526	22,765
Accumulated other comprehensive income (loss)	14			
Balance – beginning of year		70	75	51
Other comprehensive income (loss), net of taxes		(138)	(5)	24
Balance – end of year		(68)	70	75
Shareholders' equity		$31,653	$26,267	$27,381

(1) During 2017, in connection with the acquisition of direct and indirect interests in the Athabasca Oil Sands Project ("AOSP") and other assets, the Company issued non-cash share consideration of $3,818 million. See note 7.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31

(millions of Canadian dollars)	Note	2017	2016	2015
Operating activities				
Net earnings (loss)		$2,397	$(204)	$(637)
Non-cash items				
Depletion, depreciation and amortization		5,186	4,858	5,483
Share-based compensation		134	355	(46)
Asset retirement obligation accretion		164	142	173
Unrealized risk management loss		37	25	374
Unrealized foreign exchange (gain) loss		(821)	(93)	858
(Gain) loss from investments	8, 9	(11)	(299)	55
Deferred income tax expense (recovery)		640	(241)	231
Gain on acquisition, disposition and revaluation of properties	5, 6, 7	(379)	(250)	(739)
Current income tax on disposition of properties		—	—	33
Other		(110)	(32)	(22)
Abandonment expenditures		(274)	(267)	(370)
Net change in non-cash working capital	20	299	(542)	239
		7,262	3,452	5,632
Financing activities				
Issue of bank credit facilities and commercial paper, net	10, 20	2,222	342	970
Issue of medium-term notes, net	10, 20	1,791	998	107
Issue (repayment) of US dollar debt securities, net	10, 20	2,733	(834)	—
Issue of common shares on exercise of stock options		466	559	91
Dividends on common shares		(1,252)	(758)	(1,251)
Net change in non-cash working capital	20	—	—	(40)
		5,960	307	(123)
Investing activities				
Net (expenditures) proceeds on exploration and evaluation assets (1)	20	(124)	6	236
Net expenditures on property, plant and equipment (1) (2)	20	(4,574)	(3,803)	(4,704)
Acquisition of AOSP and other assets, net of cash acquired (3)	7	(8,630)	—	—
Current income tax on disposition of properties		—	—	(33)
Investment in other long-term assets		(87)	(99)	(112)
Net change in non-cash working capital	20	313	85	(852)
		(13,102)	(3,811)	(5,465)
Increase (decrease) in cash and cash equivalents		120	(52)	44
Cash and cash equivalents – beginning of year		17	69	25
Cash and cash equivalents – end of year		$137	$17	$69
Interest paid, net		$725	$617	$541
Income taxes (received) paid		$(792)	$(444)	$42

(1) Net proceeds on exploration and evaluation assets and net expenditures on property, plant and equipment in 2015 exclude non-cash share consideration of $985 million received from PrairieSky Royalty Ltd. ("PrairieSky") on the disposition of royalty income assets.

(2) Net expenditures on property, plant and equipment in 2016 exclude non-cash share consideration of $190 million received from Inter Pipeline Ltd. ("Inter Pipeline") on the disposition of the Company's interest in the Cold Lake Pipeline.

(3) The acquisition of AOSP in 2017 includes net working capital of $291 million and excludes non-cash share consideration of $3,818 million. See note 7.

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 "Oil Sands Mining and Upgrading" segment produces synthetic crude oil through bitumen mining and upgrading operations at Horizon Oil Sands ("Horizon") and through the Company's direct and indirect interest in the Athabasca Oil Sands Project ("AOSP").

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 2100, 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.

(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 consolidated from the date on which the Company obtains control. 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 determined that it 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 determined that it 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 distributions 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 expenditure overruns, liquidity concerns, financial restructuring of the investee or 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 is comprised of crude oil held for sale, including 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. An E&E asset is derecognized upon disposal or when no future economic benefits are expected to arise from its use. Any gain or loss arising on derecognition of the asset is recognized in net earnings within depletion, depreciation and amortization.

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 the related Cash Generating Units ("CGUs"), aggregated at a 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

The cost of an asset comprises its acquisition costs, 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.

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.

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 acquisition costs, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs.

Mine-related costs are depleted using the unit-of-production method based on proved reserves. Costs of the upgraders and related infrastructure located on the Horizon and AOSP sites are depreciated on the unit-of-production method based on the estimated productive capacity of the respective upgraders and related infrastructure. Other equipment is depreciated on a straight-line basis over its estimated useful life ranging from 2 to 18 years.

Midstream and Head Office
The Company capitalizes all costs that expand the capacity or extend the useful life of the midstream and head office 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 depreciated 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
A property, plant and equipment asset 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 asset) is recognized in net earnings within depletion, depreciation and amortization.
Major maintenance expenditures
Inspection costs associated with major maintenance turnarounds are capitalized and depreciated 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 an indication of impairment exists, the Company performs an impairment test related to the assets. Individual assets are grouped for impairment assessment purposes into CGUs, 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 CGUs 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 through depletion, depreciation and amortization expense.
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, depreciation and amortization, had no impairment loss been recognized for the asset in prior periods. A reversal of impairment is recognized in net earnings. After a reversal, the depletion, depreciation and amortization 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 recognized in net earnings.
(H) OVERBURDEN REMOVAL COSTS
Overburden removal costs incurred during the initial development of a mine at Horizon and AOSP 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 depleted 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 sheets. 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 sheets, 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 of the Company and its subsidiaries and partnerships 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 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, blending and feedstock, 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 Côte d'Ivoire and Gabon in 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 income 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 under a graded vesting method. 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 Company grants Performance Share Units ("PSUs") to certain executive employees. The PSUs are subject to certain performance conditions and vest three years from original grant date.

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: financial assets at amortized cost; financial liabilities at amortized cost; and fair value through profit or loss. 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 and cash equivalents, accounts receivable and certain other long-term assets are classified as financial assets at amortized cost since it is the Company’s intention to hold these assets to maturity and the related cash flows are mainly comprised of payments of principal and interest. Investments in publicly traded shares are classified as fair value through profit or loss. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as financial liabilities 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 are calculated as the difference between the amortized cost of the financial asset 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 periodically 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.

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

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 and amortized into net earnings in the periods 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.

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, except when the host contract is an asset.

(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 declared by the Board of Directors.

2. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In October 2017, the IASB issued amendments to IAS 28 “Investments in Associates and Joint Ventures” to clarify that the impairment provisions in IFRS 9 apply to financial instruments in an associate or joint venture that are not accounted for using the equity method, including long-term interests that form part of the net investment in the associate or joint venture. The amendments are effective January 1, 2019 with earlier adoption permitted. The amendments are required to be adopted retrospectively. The Company is assessing the impact of the amendments on its consolidated financial statements.

In June 2017, the IASB issued IFRIC 23 "Uncertainty over Income Tax Treatments". The interpretation provides guidance on how to reflect the effects of uncertainty in accounting for income taxes where IAS 12 is unclear. The interpretation is effective January 1, 2019. The Company is assessing the impact of this interpretation on its consolidated financial statements.

In January 2016, the IASB issued IFRS 16 “Leases”, which provides guidance on accounting for leases. The new standard replaces IAS 17 “Leases” and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees. The new standard is effective January 1, 2019 with earlier adoption permitted providing that IFRS 15 has been adopted. The new standard is required to be applied retrospectively, with a policy alternative of restating comparative prior periods or recognizing the cumulative adjustment in opening retained earnings at the date of adoption. The Company is assessing the impact of this standard on its consolidated financial statements.

IFRS 15 "Revenue from Contracts with Customers"

In May 2014, the IASB issued IFRS 15 “Revenue from Contracts with Customers” to provide guidance on the recognition of revenue and cash flows arising from an entity’s contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements. In 2015, the IASB deferred the effective date for the new standard to January 1, 2018. The new standard is required to be adopted retrospectively, with earlier adoption permitted.

Effective January 1, 2018, the Company retrospectively adopted IFRS 15. Adoption of the new standard did not have a significant impact on the Company’s recognition and measurement of revenue; however, it will require certain additional disclosures.

Upon adoption of IFRS 15, the Company applied the practical expedient such that contracts that were completed in the comparative periods have not been restated.

IFRS 9 "Financial Instruments"

Effective January 1, 2014, the Company adopted the version of IFRS 9 “Financial Instruments” issued November 2013. In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model. The amendments are effective January 1, 2018 and are required to be adopted retrospectively.

Effective January 1, 2018, the Company adopted the amendment to IFRS 9 and elected to apply the limited exemption in IFRS 9 relating to transition for impairment. Adoption of the amendment did not have a significant impact on the Company’s previous accounting for impairment of financial assets.

3. 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, asset retirement obligations, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserves estimates are based on engineering data, estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations and judgements. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information.

(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 of 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 reserves life. These differences 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 a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately 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 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 stock options granted under its 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 CGUs' 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, asset retirement obligations, future development and operating costs, after-tax discount rates currently ranging from 10% to 12%, and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

(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.

4. INVENTORY

	2017	2016
Product inventory	$285	$263
Materials and supplies	609	426
	$894	$689

The Company recorded a write-down of its product inventory of $33 million from cost to net realizable value as at December 31, 2017 (2016 - $73 million).

Principal Documents Exhibits

5. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2015	$2,500	$ —	$ 86	$ —	$2,586
Additions	20	—	9	—	29
Transfers to property, plant and equipment	(211)	—	—	—	(211)
Disposals/derecognitions	(3)	—	(18)	—	(21)
Foreign exchange adjustments	—	—	(1)	—	(1)
At December 31, 2016	2,306	—	76	—	2,382
Additions	144	—	15	—	159
Acquisition of AOSP and other assets (note 7)	31	—	—	259	290
Transfers to property, plant and equipment	(198)	—	—	—	(198)
Disposals/derecognitions	(1)	—	—	—	(1)
At December 31, 2017	$2,282	$ —	$ 91	$ 259	$2,632

On May 31, 2017, the Company completed the acquisition of AOSP and other assets in the Oil Sands Mining and Upgrading and North America Exploration and Production segments, including exploration and evaluation assets of $290 million. Refer to note 7 regarding the acquisition of AOSP and other assets.

During 2017, the Company disposed of a number of North America exploration and evaluation assets with a net book value $1 million for consideration of $36 million, resulting in a pre-tax gain on sale of properties of $35 million.

During 2016, the Company disposed of a number of North America exploration and evaluation assets totaling $3 million for consideration of $35 million, resulting in a pre-tax gain on sale of properties of $32 million. In addition, in connection with the Company's notice of withdrawal from Block CI-12 in Côte d'Ivoire, Offshore Africa, the Company derecognized $18 million of exploration and evaluation assets.

6. 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, 2015	$60,540	$7,414	$5,173	$24,343	$577	$378	$98,425
Additions	1,462	186	116	2,822	6	17	4,609
Transfers from E&E assets	211	—	—	—	—	—	211
Disposals/derecognitions	(566)	—	—	(127)	(349)	—	(1,042)
Foreign exchange adjustments and other	—	(220)	(157)	—	—	—	(377)
At December 31, 2016	61,647	7,380	5,132	27,038	234	395	101,826
Additions (1)	3,003	255	101	1,660	194	19	5,232
Acquisition of AOSP and other assets (note 7)	349	—	—	13,832	—	—	14,181
Transfers from E&E assets	198	—	—	—	—	—	198
Disposals/derecognitions	(381)	—	—	(446)	—	—	(827)
Foreign exchange adjustments and other	—	(509)	(352)	—	—	—	(861)
At December 31, 2017	$64,816	$7,126	$4,881	$42,084	$428	$414	$119,749
Accumulated depletion and depreciation							
At December 31, 2015	$35,347	$5,264	$3,659	$2,294	$132	$254	$46,950
Expense	3,440	457	243	662	11	27	4,840
Disposals/derecognitions	(486)	—	—	(127)	(28)	—	(641)
Foreign exchange adjustments and other	10	(137)	(105)	(1)	—	—	(233)
At December 31, 2016	38,311	5,584	3,797	2,828	115	281	50,916
Expense	3,220	509	205	1,220	9	23	5,186
Disposals/derecognitions	(381)	—	—	(446)	—	—	(827)
Foreign exchange adjustments and other	1	(440)	(283)	26	—	—	(696)
At December 31, 2017	$41,151	$5,653	$3,719	$3,628	$124	$304	$54,579
Net book value							
- at December 31, 2017	$23,665	$1,473	$1,162	$38,456	$304	$110	$65,170
- at December 31, 2016	$23,336	$1,796	$1,335	$24,210	$119	$114	$50,910

(1) Additions in Midstream include the revaluation of a previously held joint interest in certain pipeline system assets.

Project costs not subject to depletion and depreciation	2017	2016
Kirby Thermal Oil Sands – North	$944	$846

Principal Documents Exhibits

On May 31, 2017, the Company completed the acquisition of AOSP and other assets in the Oil Sands Mining and Upgrading and North America Exploration and Production segments, including property, plant and equipment of $14,181 million. Refer to note 7 regarding the acquisition of AOSP and other assets.

During 2017, the Company acquired a number of other producing crude oil and natural gas properties in the North America Exploration and Production segment, including exploration and evaluation assets of $27 million (2016 - $nil; 2015 - $37 million), along with the remaining interest in certain pipeline system assets in the Midstream segment, for net cash consideration of $1,013 million (2016 – $159 million; 2015 – $406 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 $63 million (2016 – $30 million; 2015 – $133 million). No net deferred income tax liabilities were recognized on these acquisitions (2016 - $nil; 2015 - $nil).

Further, in connection with the acquisition of pipeline system assets in the Midstream segment, the Company recognized a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in the pipeline.

During 2016, in the Midstream segment, the Company disposed of its interest in the Cold Lake Pipeline, comprising $321 million of property, plant and equipment for total net consideration of $539 million, resulting in a pre and after-tax gain of $218 million. Total net consideration was comprised of $349 million in cash, together with $190 million of non-cash share consideration of approximately 6.4 million common shares of Inter Pipeline Ltd. (“Inter Pipeline”) with a value of $29.57 per common share, determined as of the closing date.

As at December 31, 2017, the Company assessed the recoverability of its property, plant and equipment and its exploration and evaluation assets, and determined the carrying amounts to be recoverable.

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 2017, pre-tax interest of $82 million (2016 – $233 million; 2015 – $244 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.8% (2016 – 3.9%; 2015 – 3.9%).

7. ACQUISITION OF INTERESTS IN THE ATHABASCA OIL SANDS PROJECT AND OTHER ASSETS

On May 31, 2017, the Company completed the acquisition of a direct and indirect 70% interest in AOSP from Shell Canada Limited and certain subsidiaries (“Shell”) and an affiliate of Marathon Oil Corporation (“Marathon"), including a 70% interest in the mining and extraction operations north of Fort McMurray, Alberta, 70% of the Scotford Upgrader and Quest Carbon Capture and Storage ("CCS") project, and a 100% working interest in the Peace River thermal in situ operations and Cliffdale heavy oil field, as well as other oil sands leases. The Company also assumed certain pipeline and other commitments (see note 19). The Company consolidates its direct and indirect interest in the assets, liabilities, revenue and expenses of AOSP and other assets in proportion to the Company’s interests.

Total purchase consideration of $12,541 million, subject to closing adjustments, was comprised of cash payments of $8,217 million, approximately 97.6 million common shares of the Company issued to Shell with a fair value of approximately $3,818 million, and deferred purchase consideration of $506 million (US$375 million) payable to Marathon in March 2018. The fair value of the Company's common shares was determined using the market price of the shares as at the acquisition date.

In connection with the acquisition of AOSP and other assets, the Company arranged acquisition financing of $1.8 billion of medium-term notes in Canada, US$3 billion of long-term notes in the United States and a $3 billion non-revolving term loan facility (see note 10).

The acquisition has been accounted for as a business combination using the acquisition method of accounting. The allocation of the purchase price was based on management's best estimates of the fair value of the assets and liabilities acquired as at the acquisition date. Key assumptions used in the determination of estimated fair value were future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and operating costs, discount rates, income taxes and foreign exchange rates. The fair value of accounts receivable, inventory, accounts payable and accrued liabilities approximated their carrying values due to the liquid nature of the assets and liabilities.

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The following provides a summary of the net assets acquired and (liabilities) assumed relating to the acquisition:

Cash	$93
Other working capital	291
Property, plant and equipment	14,181
Exploration and evaluation assets	290
Asset retirement obligations	(721)
Other long-term liabilities	(73)
Deferred income taxes	(1,287)
Net assets acquired	$12,774
Total purchase consideration	12,541
Gain on acquisition before transaction costs	$233

The Company recognized a gain of $230 million, net of transaction costs of $3 million, representing the excess of the fair value of the net assets acquired compared to total purchase consideration. The above amounts are estimates, and may be subject to change based on the receipt of new information.

As a result of the acquisitions, revenue increased by $2,872 million to $16,651 million and net operating income (comprised of revenue less production, and transportation, blending, and feedstock expense) increased by $1,166 million to $8,138 million for the year ended December 31, 2017. If the acquisitions had occurred on January 1, 2017, the Company estimates that pro forma revenue would have increased by $2,181 million to $18,832 million and pro forma net operating income would have increased by $735 million to $8,873 million for the year ended December 31, 2017. Readers are cautioned that pro forma revenue and pro forma net operating income are not necessarily indicative of the results of operations that would have resulted had the acquisition actually occurred on January 1, 2017, or of future results. Actual results would have been different and those differences may have been material in comparison to the pro forma information provided. Pro forma results are based on available historical information for the assets as provided to the Company and do not include any synergies that have arisen subsequent to the acquisition date.

8. INVESTMENTS

As at December 31, 2017 and 2016, the Company had the following investments:

	2017	2016
Investment in PrairieSky Royalty Ltd.	$726	$723
Investment in Inter Pipeline Ltd.	167	190
	$893	$913

Investment in PrairieSky Royalty Ltd.

During 2015, as partial consideration for the disposal of a number of North America royalty income assets, the Company received non-cash share consideration of $985 million, comprised of approximately 44.4 million common shares of PrairieSky Royalty Ltd. ("PrairieSky") at $22.16 per common share determined as of the closing date. PrairieSky is in the business of acquiring and managing oil and gas royalty income assets through indirect third-party oil and gas development.

During 2016, the Company completed the net distribution of approximately 21.8 million PrairieSky common shares to the shareholders of record of the Company as at June 3, 2016, completing the previously announced Plan of Arrangement. The distribution was recognized as a return of capital of $546 million. Subsequent to the distribution, the Company's ownership interest in PrairieSky was less than 10% of the issued and outstanding common shares of PrairieSky.

The Company's investment of 22.6 million common shares does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at December 31, 2017, the Company's investment in PrairieSky was classified as a current asset.

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The (gain) loss from the investment in PrairieSky was comprised as follows:

	2017	2016	2015
Fair value (gain) loss from PrairieSky	$(3)	$(292)	$ 11
Dividend income from PrairieSky	(17)	(27)	(5)
	$(20)	$(319)	$ 6

Investment in Inter Pipeline Ltd.

During 2016, as partial consideration for the disposal of the Company's interest in the Cold Lake Pipeline, the Company received non-cash share consideration of $190 million, comprised of approximately 6.4 million common shares of Inter Pipeline Ltd. ("Inter Pipeline") at $29.57 per common share determined as of the closing date. Inter Pipeline is in the business of petroleum transportation, natural gas liquids processing, and bulk liquid storage in Western Canada and Europe.

The Company's investment of 6.4 million common shares of Inter Pipeline does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at December 31, 2017, the Company's investment in Inter Pipeline was classified as a current asset.

The loss (gain) from the investment in Inter Pipeline was comprised as follows:

	2017	2016	2015
Fair value loss from Inter Pipeline	$ 23	$ —	$ —
Dividend income from Inter Pipeline	(10)	(1)	—
	$ 13	$ (1)	$ —

9. OTHER LONG-TERM ASSETS

	2017	2016
Investment in North West Redwater Partnership	$292	$261
North West Redwater Partnership subordinated debt (1)	510	385
Risk Management (note 18)	204	489
Other	241	168
	1,247	1,303
Less: current portion	79	283
	$1,168	$1,020

(1) Includes accrued interest.

Investment in North West Redwater Partnership

The Company's 50% interest in Redwater Partnership is accounted for using the equity method based on Redwater Partnership’s voting and decision-making structure and legal form. 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.

The facility capital cost ("FCC") budget for the Project is currently estimated to be $9,500 million with project completion targeted for third quarter 2018. Productivity challenges during construction have continued to result in upward budgetary pressures that may result in a further increase in FCC of up to 2%. During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. To December 31, 2017, each party has provided $411 million of subordinated debt, together with accrued interest thereon of $99 million, for a Company total of $510 million. Any additional subordinated debt financing is not expected to be significant.

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

During 2017, Redwater Partnership issued $750 million of 2.80% series J senior secured bonds due June 2027 and $750 million of 3.65% series K senior secured bonds due June 2035.

During 2016, Redwater Partnership issued $550 million of 4.25% series F senior secured bonds due June 2029, $500 million of 4.75% series G senior secured bonds due June 2037, $500 million of 4.15% series H senior secured bonds due June 2033, and $500 million of 4.35% series I senior secured bonds due January 2039.

As at December 31, 2017, Redwater Partnership had additional borrowings of $1,870 million under its secured $3,500 million syndicated credit facility, maturing June 2018. Subsequent to December 31, 2017, Redwater Partnership extended $2,000 million of the $3,500 revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

The assets, liabilities, partners' equity and equity income related to Redwater Partnership and the Company's 50% interest at December 31, 2017 and 2016 were comprised as follows:

	2017		2016	
	Redwater Partnership 100% interest	Company 50% interest	Redwater Partnership 100% interest	Company 50% interest
Current assets	$330	$ 165	$96	$ 48
Non-current assets	$10,540	$ 5,270	$8,258	$ 4,129
Current liabilities	$2,476	$ 1,238	$572	$ 286
Non-current liabilities	$7,810	$ 3,905	$7,260	$ 3,630
Partners' equity	$584	$ 292	$522	$ 261
Equity income	$(62)	$ (31)	$(14)	$ (7)

10. LONG-TERM DEBT

	2017	2016
Canadian dollar denominated debt, unsecured		
Bank credit facilities	$3,544	$2,758
Medium-term notes		
3.05% debentures due June 19, 2019	500	500
2.60% debentures due December 3, 2019	500	500
2.05% debentures due June 1, 2020	900	—
2.89% debentures due August 14, 2020	1,000	1,000
3.31% debentures due February 11, 2022	1,000	1,000
3.55% debentures due June 3, 2024	500	500
3.42% debentures due December 1, 2026	600	—
4.85% debentures due May 30, 2047	300	—
	8,844	6,258
US dollar denominated debt, unsecured		
Bank credit facilities (December 31, 2017 - US$1,839 million; December 31, 2016 - US$905 million)	2,300	1,213
Commercial paper (December 31, 2017 - US$500 million; December 31, 2016 - US$250 million)	625	336
US dollar debt securities		
5.70% due May 15, 2017 (US$1,100 million)	—	1,477
1.75% due January 15, 2018 (US$600 million)	751	806
5.90% due February 1, 2018 (US$400 million)	501	537
3.45% due November 15, 2021 (US$500 million)	625	671
2.95% due January 15, 2023 (US$1,000 million)	1,252	—
3.80% due April 15, 2024 (US$500 million)	625	671
3.90% due February 1, 2025 (US$600 million)	751	806
3.85% due June 1, 2027 (US$1,250 million)	1,566	—
7.20% due January 15, 2032 (US$400 million)	501	537
6.45% due June 30, 2033 (US$350 million)	438	470
5.85% due February 1, 2035 (US$350 million)	438	470
6.50% due February 15, 2037 (US$450 million)	563	604
6.25% due March 15, 2038 (US$1,100 million)	1,377	1,477
6.75% due February 1, 2039 (US$400 million)	501	537
4.95% due June 1, 2047 (US$750 million)	939	—
	13,753	10,612
Long-term debt before transaction costs and original issue discounts, net	22,597	16,870
Less: original issue discounts, net [(1)]	18	10
transaction costs [(1)] [(2)]	121	55
	22,458	16,805
Less: current portion of commercial paper	625	336
current portion of other long-term debt [(1)] [(2)]	1,252	1,476
	$20,581	$14,993

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

(2) 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, 2017, the Company had in place bank credit facilities of $11,050 million, as described below, of which $4,112 million was available. This excludes certain other dedicated credit facilities supporting letters of credit.

- a $100 million demand credit facility;
- a $750 million non-revolving term credit facility maturing February 2019;
- a $125 million non-revolving term credit facility maturing February 2019;
- a $2,200 million non-revolving term credit facility maturing October 2019;
- a $3,000 million non-revolving term credit facility maturing May 2020;
- a $2,425 million revolving syndicated credit facility maturing June 2020;
- a $2,425 million revolving syndicated credit facility with $330 million maturing in June 2019 and $2,095 million maturing June 2021; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During 2017, the Company extended $2,095 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The remaining $330 million outstanding under this facility continues under the previous terms and matures in June 2019. The other $2,425 million revolving credit facility matures in June 2020. The revolving credit facilities are extendible annually 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 2017, the $1,500 million non-revolving term credit facility was increased to $2,200 million and the maturity date was extended to October 2019 from April 2018. Borrowings under the $2,200 million non-revolving credit facility 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. As at December 31, 2017, the $2,200 million facility was fully drawn.

Borrowings under the $750 million and $125 million non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at December 31, 2017, the $750 million and $125 million facilities were each fully drawn. Subsequent to December 31, 2017, the Company extended the $750 million non-revolving term credit facility originally due February 2019 to February 2021 and fully repaid and cancelled the $125 million non-revolving term credit facility.

In addition to the credit facilities described above, during 2017 the Company entered into a $3,000 million non-revolving term loan facility to finance the acquisition of AOSP and other assets. This facility matures in May 2020 and is subject to annual amortization of 5% of the original balance. Borrowings under the term loan facility 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. The facility also supports a US$375 million letter of credit relating to the deferred purchase consideration payable to Marathon in March 2018. As at December 31, 2017, the $3,000 million facility was fully drawn. Subsequent to December 31, 2017, the Company repaid and cancelled $150 million of the facility; $2,850 million remains outstanding.

The Company's borrowings under its US commercial paper program are authorized up to a maximum US$2,500 million. 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, 2017 was 2.2% (December 31, 2016 – 1.9%), and on total long-term debt outstanding for the year ended December 31, 2017 was 3.8% (December 31, 2016 – 3.9%).

At December 31, 2017, letters of credit and guarantees aggregating $866 million were outstanding, including letters of credit of $651 million related to AOSP (including the deferred purchase consideration payable to Marathon in March 2018), a $39 million financial guarantee related to Horizon and $63 million of letters of credit related to North Sea operations.

Medium-Term Notes

During 2017, the Company issued $900 million of 2.05% medium-term notes due June 2020, $600 million of 3.42% medium-term notes due December 2026 and $300 million of 4.85% medium-term notes due May 2047. Proceeds from the securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

During 2016, the Company issued $1,000 million of 3.31% medium-term notes due February 2022.

US Dollar Debt Securities

During 2017, the Company repaid US$1,100 million of 5.70% notes, and issued US$1,000 million of 2.95% notes due January 2023, US$1,250 million of 3.85% notes due June 2027 and US$750 million of 4.95% notes due June 2047. Proceeds from the debt securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

Subsequent to December 31, 2017, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

During 2016, the Company repaid US$500 million of three-month LIBOR plus 0.375% notes and US$250 million of 6.00% notes.

Scheduled Debt Repayments

Scheduled debt repayments are as follows:

Year	Repayment
2018	$ 2,027
2019	$ 4,228
2020	$ 4,231
2021	$ 760
2022	$ 1,000
Thereafter	$ 10,351

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11. OTHER LONG-TERM LIABILITIES

	2017	2016
Asset retirement obligations	$4,327	$3,243
Share-based compensation	414	426
Risk management (note 18)	103	—
Other [(1)]	565	17
	5,409	3,686
Less: current portion	1,012	463
	$4,397	$3,223

(1) Included in Other at December 31, 2017 is $469 million (US$375 million) of deferred purchase consideration payable to Marathon in March 2018.

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 4.7% (2016 – 5.2%; 2015 – 5.9%). Reconciliations of the discounted asset retirement obligations were as follows:

	2017	2016	2015
Balance – beginning of year	$3,243	$2,950	$4,221
Liabilities incurred	12	3	7
Liabilities acquired, net	784	30	129
Liabilities settled	(274)	(267)	(370)
Asset retirement obligation accretion	164	142	173
Revision of cost, inflation rates and timing estimates	(40)	(68)	(313)
Change in discount rate	509	493	(1,150)
Foreign exchange adjustments	(71)	(40)	253
Balance – end of year	4,327	3,243	2,950
Less: current portion	92	95	101
	$4,235	$3,148	$2,849

Segmented Asset Retirement Obligations

	2017	2016
Exploration and Production		
North America	$1,840	$1,444
North Sea	755	837
Offshore Africa	245	244
Oil Sands Mining and Upgrading	1,486	717
Midstream	1	1
	$4,327	$3,243

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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.

	2017	2016	2015
Balance – beginning of year	$426	$128	$203
Share-based compensation expense (recovery)	134	355	(46)
Cash payment for stock options surrendered	(6)	(7)	(1)
Transferred to common shares	(154)	(117)	(18)
Charged to (recovered from) Oil Sands Mining and Upgrading, net	14	67	(10)
Balance – end of year	414	426	128
Less: current portion	348	368	105
	$66	$58	$23

Included within share-based compensation expense for the year ended December 31, 2017 was $5 million (2016 – $nil; 2015 – $nil) related to PSUs granted to certain executive employees.

The fair value of stock options outstanding was estimated using the Black-Scholes valuation model with the following weighted average assumptions:

	2017	2016	2015
Fair value	$11.82	$11.41	$3.06
Share price	$44.92	$42.79	$30.22
Expected volatility	27.1%	30.7%	28.6%
Expected dividend yield	2.5%	2.3%	3.0%
Risk free interest rate	1.8%	0.9%	0.6%
Expected forfeiture rate	5.0%	5.0%	4.8%
Expected stock option life (1)	4.5 years	4.6 years	4.5 years

(1) At original time of grant.

The intrinsic value of vested stock options at December 31, 2017 was $195 million (2016 – $191 million; 2015 – $10 million).

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12. INCOME TAXES

The provision for income tax was as follows:

Expense (recovery)	2017	2016	2015
Current corporate income tax – North America	$(145)	$(377)	$86
Current corporate income tax – North Sea	57	(74)	(117)
Current corporate income tax – Offshore Africa	45	22	17
Current PRT [(1)] – North Sea	(132)	(198)	(258)
Other taxes	11	9	11
Current income tax	(164)	(618)	(261)
Deferred corporate income tax	586	(106)	216
Deferred PRT [(1)] – North Sea	54	(135)	15
Deferred income tax	640	(241)	231
Income tax	$476	$(859)	$(30)

(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 (loss) before taxes. The reasons for the difference are as follows:

	2017	2016	2015
Canadian statutory income tax rate	27.0%	27.0%	26.0%
Income tax provision at statutory rate	$ 776	$(287)	$(173)
Effect on income taxes of:			
UK PRT and other taxes	(67)	(324)	(232)
Impact of deductible UK PRT and other taxes on corporate income tax	28	131	119
Foreign and domestic tax rate differentials	(43)	(54)	(157)
Non-taxable portion of capital gains/losses	(86)	(80)	36
Stock options exercised for common shares	33	94	(12)
Income tax rate and other legislative changes	10	(107)	362
Non-taxable gain on corporate acquisitions	(63)	—	—
Revisions arising from prior year tax filings	(3)	(120)	32
Change in unrecognized capital loss carryforward asset	(86)	(80)	36
Other	(23)	(32)	(41)
Income tax expense (recovery)	$ 476	$(859)	$(30)

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

	2017	2016
Deferred income tax liabilities		
Property, plant and equipment and exploration and evaluation assets	$12,484	$10,259
Unrealized risk management activities	20	62
PRT deduction for corporate income tax	7	29
Investments	96	98
Investment in North West Redwater Partnership	252	222
	12,859	10,670
Deferred income tax assets		
Asset retirement obligations	(1,264)	(983)
Loss carryforwards	(523)	(390)
Unrealized foreign exchange loss on long-term debt	(29)	(149)
Deferred PRT	(18)	(73)
Other	(50)	(2)
	(1,884)	(1,597)
Net deferred income tax liability	$10,975	$9,073

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

	2017	2016	2015
Property, plant and equipment and exploration and evaluation assets	$541	$37	$(7)
Timing of partnership items	—	(261)	(176)
Unrealized foreign exchange loss (gain) on long-term debt	120	63	(222)
Unrealized risk management activities	(46)	(44)	(5)
Asset retirement obligations	(88)	(20)	522
Loss carryforwards	48	(221)	(53)
Investments	(2)	38	60
Investment in North West Redwater Partnership	30	81	106
Deferred PRT	54	(135)	15
PRT deduction for corporate income tax	(21)	61	(5)
Other	4	160	(4)
	$640	$(241)	$231

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

	2017	2016	2015
Balance – beginning of year	$9,073	$9,344	$8,970
Deferred income tax expense (recovery)	640	(241)	231
Deferred income tax expense (recovery) included in other comprehensive income	4	(5)	(4)
Foreign exchange adjustments	(29)	(25)	147
Business combinations (note 7)	1,287	—	—
Balance – end of year	$10,975	$9,073	$9,344

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 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $10 million.

During 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. In addition, the UK government also enacted legislation to reduce the PRT rate from 35% to 0% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes are still recoverable at a PRT rate of 50%. As a result of these tax changes, the Company’s deferred PRT liability was reduced by $228 million and the deferred corporate income tax liability was increased by $114 million.

During 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company’s deferred corporate income tax liability was increased by $579 million.

During 2015, the UK government enacted legislation that reduced the supplementary charge on oil and gas profits from 32% to 20% effective January 1, 2015. In addition, the legislation also reduced the PRT rate from 50% to 35% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to prior taxation years for PRT purposes were still recoverable at the previous tax rate of 50%. The legislation also replaced the existing Brownfield Allowance with a new Investment Allowance on qualifying capital expenditures, effective April 1, 2015. The new Investment Allowance is deductible for supplementary charge purposes, subject to certain restrictions. As a result of these tax changes, the Company’s deferred corporate income tax liability was reduced by $217 million and the deferred PRT liability was reduced by $11 million.

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 reported 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 has not recognized 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 North American tax pools of approximately $650 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 Common shares	2017 Number of shares (thousands)	Amount	2016 Number of shares (thousands)	Amount
Balance – beginning of year	1,110,952	$ 4,671	1,094,668	$ 4,541
Issued for the acquisition of AOSP and other assets (note 7)	97,561	3,818	—	—
Issued upon exercise of stock options	14,256	466	16,284	559
Previously recognized liability on stock options exercised for common shares	—	154	—	117
Return of capital on PrairieSky Royalty Ltd. share distribution (note 8)	—	—	—	(546)
Balance – end of year	1,222,769	$ 9,109	1,110,952	$ 4,671

Preferred Shares

Preferred shares are issuable in a 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 each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On February 28, 2018, the Board of Directors declared a quarterly dividend of $0.335 per common share, an increase from the previous quarterly dividend of $0.275 per common share. The dividend is payable on April 1, 2018. On March 1, 2017, the Board of Directors declared a quarterly dividend of $0.275 per common share, beginning with the dividend payable on April 1, 2017. On November 2, 2016, the Board of Directors declared a quarterly dividend of $0.25 per common share, beginning with the dividend payable on January 1, 2017. On March 2, 2016, the Board of Directors declared a quarterly dividend of $0.23 per common share, beginning with the dividend payable on April 1, 2016. On March 4, 2015, the Board of Directors declared a quarterly dividend of $0.23 per common share, beginning with the dividend payable on April 1, 2015.

Normal Course Issuer Bid

On May 16, 2017, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 27,931,135 common shares, over a 12 month period commencing May 23, 2017 and ending May 22, 2018. During 2017, 2016 and 2015, the Company did not purchase any common shares for cancellation.

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, 2017 and 2016:

	2017		2016	
	Stock options (thousands)	Weighted average exercise price	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	58,299	$ 34.22	74,615	$ 34.88
Granted	16,052	$ 42.07	11,002	$ 34.97
Surrendered for cash settlement	(626)	$ 33.18	(817)	$ 34.47
Exercised for common shares	(14,256)	$ 32.66	(16,284)	$ 34.31
Forfeited	(3,433)	$ 37.53	(10,217)	$ 39.66
Outstanding – end of year	56,036	$ 36.67	58,299	$ 34.22
Exercisable – end of year	18,282	$ 34.25	20,747	$ 33.75

The range of exercise prices of stock options outstanding and exercisable at December 31, 2017 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
$22.90-$24.99	3,657	3.03	$ 22.90	1,116	$ 22.90
$25.00-$29.99	8,390	2.34	$ 28.72	3,967	$ 28.57
$30.00-$34.99	10,047	1.61	$ 33.31	5,557	$ 33.49
$35.00-$39.99	13,523	3.29	$ 37.21	4,190	$ 35.88
$40.00-$44.99	19,417	4.15	$ 43.60	3,118	$ 43.55
$45.00-$46.74	1,002	3.63	$ 45.61	334	$ 45.09
	56,036	3.13	$ 36.67	18,282	$ 34.25

14. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	2017	2016
Derivative financial instruments designated as cash flow hedges	$47	$ 27
Foreign currency translation adjustment	(115)	43
	$(68)	$ 70

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 net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net 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, 2017, the ratio was within the target range at 41%.

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.

	2017	2016
Long-term debt, net [1]	$22,321	$16,788
Total shareholders' equity	$31,653	$26,267
Debt to book capitalization	41%	39%

(1) Includes the current portion of long-term debt, net of cash and cash equivalents.

16. NET EARNINGS (LOSS) PER COMMON SHARE

		2017	2016	2015
Weighted average common shares outstanding – basic (thousands of shares)		1,175,094	1,100,471	1,093,862
Effect of dilutive stock options (thousands of shares)		7,729	—	—
Weighted average common shares outstanding – diluted (thousands of shares)		1,182,823	1,100,471	1,093,862
Net earnings (loss)		$ 2,397	$ (204)	$ (637)
Net earnings (loss) per common share	– basic	$ 2.04	$ (0.19)	$ (0.58)
	– diluted	$ 2.03	$ (0.19)	$ (0.58)

In 2017, the Company excluded 17,547,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share.

17. INTEREST AND OTHER FINANCING EXPENSE

	2017	2016	2015
Interest and other financing expense:			
Long-term debt	$810	$664	$618
Other [1]	—	—	1
	810	664	619
Less: amounts capitalized on qualifying assets	82	233	244
Total interest and other financing expense	728	431	375
Total interest income	(97)	(48)	(53)
Net interest and other financing expense	$631	$383	$322

(1) Includes the fair value impact of interest rate swaps on US dollar debt securities.

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18. FINANCIAL INSTRUMENTS

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

2017					
Asset (liability)	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$2,397	$ —	$ —	$—	$2,397
Investments	—	893	—	—	893
Other long-term assets	510	—	204	—	714
Accounts payable	—	—	—	(775)	(775)
Accrued liabilities	—	—	—	(2,597)	(2,597)
Other long-term liabilities [1]	—	(38)	(65)	(469)	(572)
Long-term debt [2]	—	—	—	(22,458)	(22,458)
	$2,907	$ 855	$ 139	$(26,299)	$(22,398)

2016					
Asset (liability)	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$1,434	$ —	$ —	$—	$1,434
Investments	—	913	—	—	913
Other long-term assets	385	4	485	—	874
Accounts payable	—	—	—	(595)	(595)
Accrued liabilities	—	—	—	(2,222)	(2,222)
Long-term debt [2]	—	—	—	(16,805)	(16,805)
	$1,819	$ 917	$ 485	$(19,622)	$(16,401)

(1) Includes $469 million (US$375 million) of deferred purchase consideration payable to Marathon in March 2018.

(2) 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. The fair values of the Company's investments, recurring other long-term assets (liabilities) and fixed rate long-term debt are outlined below:

	2017			
	Carrying amount	Fair value		
Asset (liability) [1] [2]		Level 1	Level 2	Level 3
Investments [3]	$893	$893	$—	$—
Other long-term assets [4]	$714	$—	$204	$510
Other long-term liabilities	$(103)	$—	$(103)	$—
Fixed rate long-term debt [5] [6]	$(15,989)	$(17,259)	$—	$—

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Asset (liability) (1) (2)	2016 Carrying amount	Fair value Level 1	Level 2	Level 3
Investments (3)	$913	$913	$—	$—
Other long-term assets (4)	$874	$—	$489	$385
Fixed rate long-term debt (5) (6)	$(12,498)	$(13,217)	$—	$—

(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, and deferred purchase consideration payable to Marathon in March 2018).
(2) There were no transfers between Level 1, 2 and 3 financial instruments.
(3) The fair value of the investments are based on quoted market prices.
(4) The fair value of Redwater Partnership subordinated debt is based on the present value of future cash receipts.
(5) The fair value of fixed rate long-term debt has been determined based on quoted market prices.
(6) Includes the current portion of fixed rate long-term debt.

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)	2017	2016
Derivatives held for trading		
Foreign currency forward contracts	$(38)	$10
Natural gas AECO swaps	—	(6)
Cash flow hedges		
Foreign currency forward contracts	(71)	16
Cross currency swaps	210	469
	$101	$489
Included within:		
Current portion of other long-term (liabilities) assets	$(103)	$222
Other long-term assets	204	267
	$101	$489

During 2017, the Company recognized a gain of $5 million (2016 – gain of $7 million, 2015 – gain of $5 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value of derivative financial instruments in 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 as applicable, 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.

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Risk Management

The Company periodically 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 asset were recognized in the financial statements as follows:

Asset (liability)	2017	2016
Balance – beginning of year	$489	$854
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	(37)	(25)
Foreign exchange	(375)	(304)
Other comprehensive income (loss)	24	(36)
Balance – end of year	101	489
Less: current portion	(103)	222
	$204	$267

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

	2017	2016	2015
Net realized risk management (gain) loss	$ (2)	$ 8	$(843)
Net unrealized risk management loss	37	25	374
	$ 35	$ 33	$(469)

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, 2017, the Company had no derivative financial instruments outstanding.

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. 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, 2017, 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 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 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, 2017 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 2018 – Nov 2021	US$500	1.022	3.45 %	3.96 %
	Jan 2018 – Mar 2038	US$550	1.170	6.25 %	5.76 %

All cross currency swap derivative financial instruments were designated as hedges at December 31, 2017 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2017 the Company had US$3,705 million of foreign currency forward contracts outstanding, with terms of up to 90 days, including US$2,339 million designated as cash flow hedges.

Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's 2017 net earnings and other comprehensive income (loss) to changes in the fair value of financial instruments outstanding as at December 31, 2017, 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) to net earnings	(Increase) decrease to other comprehensive loss
Interest rate risk		
Increase interest rate 1%	$ (42)	$ (16)
Decrease interest rate 1%	$ 42	$ 19
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (105)	$ —
Decrease exchange rate by US$0.01	$ 101	$ —

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, 2017, 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. At December 31, 2017, the Company had net risk management assets of $187 million with specific counterparties related to derivative financial instruments (December 31, 2016 – $489 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 were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$775	$—	$—	$ —
Accrued liabilities	$2,597	$—	$—	$ —
Other long-term liabilities (1)	$572	$—	$—	$ —
Long-term debt (2) (3)	$2,027	$4,228	$5,991	$ 10,351

(1) Includes $469 million (US$375 million) of deferred purchase consideration payable to Marathon in March 2018.

(2) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.

(3) In addition to the financial liabilities disclosed above, estimated interest and other financing payments related to long-term debt are as follows: less than one year, $842 million; one to less than two years, $755 million; two to less than five years, $1,712 million; and thereafter, $5,384 million. Interest payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2017.

19. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2018	2019	2020	2021	2022	Thereafter
Product transportation and pipeline	$680	$584	$526	$482	$422	$ 3,868
Offshore equipment operating leases	$181	$92	$70	$68	$8	$ —
Office leases	$43	$42	$42	$39	$30	$ 118
Other (1)	$87	$41	$40	$39	$43	$ 333

(1) In addition to the amounts disclosed above, beginning on the earlier of the commercial operations date of the Redwater refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the

debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years. See Note 9.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of its various development projects. 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.

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20. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	2017	2016	2015
Changes in non-cash working capital			
Accounts receivable	$(977)	$(142)	$615
Current income tax assets	527	(165)	(447)
Inventory	81	(79)	142
Prepaids and other	(28)	14	11
Accounts payable	175	31	7
Accrued liabilities	365	(116)	(981)
Other long-term liabilities (1)	469	—	—
Net changes in non-cash working capital	$612	$(457)	$(653)
Relating to:			
Operating activities	$299	$(542)	$239
Financing activities	—	—	(40)
Investing activities	313	85	(852)
	$612	$(457)	$(653)

	2017	2016	2015
Expenditures on exploration and evaluation assets	$159	$29	$180
Net proceeds on sale of exploration and evaluation assets (2)	(35)	(35)	(416)
Net expenditures (proceeds) on exploration and evaluation assets	$124	$(6)	$(236)
Expenditures on property, plant and equipment	$4,574	$4,152	$5,118
Net proceeds on sale of property, plant and equipment (2) (3)	—	(349)	(414)
Net expenditures on property, plant and equipment	$4,574	$3,803	$4,704

(1) Included in other long-term liabilities at December 31, 2017 is $469 million (US$375 million) of deferred purchase consideration payable to Marathon in March 2018.

(2) Net proceeds on exploration and evaluation assets and net expenditures on property, plant and equipment in 2015 exclude non-cash share consideration of $985 million received from PrairieSky on the disposition of royalty income assets.

(3) Net expenditures on property, plant and equipment in 2016 exclude non-cash share consideration of $190 million received from Inter Pipeline on the disposition of the Company's interest in the Cold Lake Pipeline.

The following table summarizes movements in the Company's liabilities arising from financing activities for the year ended December 31, 2017:

	Long-term debt	Cash flow hedges on US dollar debt securities	Liabilities from financing activities
At December 31, 2016	$16,805	$ (485)	$16,320
Changes from financing cash flows:			
Issue of long-term debt, net (1)	6,622	—	6,622
Settlement of hedge instruments, net	—	124	124
Changes in foreign exchange and fair value (2)	(969)	222	(747)
At December 31, 2017	$22,458	$ (139)	$22,319

(1) Includes original issue discounts and premiums, and directly attributable transaction costs.

(2)

Includes foreign exchange (gain) loss, changes in the fair value of cash flow hedges on US dollar debt and the amortization of original issue discounts and premiums and directly attributable transaction costs.

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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.

	North America			North Sea			Offshore Africa		
(millions of Canadian dollars)	2017	2016	2015	2017	2016	2015	2017	2016	2015
Segmented product sales	$9,161	$7,209	$9,222	$784	$570	$638	$632	$603	$482
Less: royalties	(809)	(524)	(732)	(1)	(1)	(1)	(41)	(26)	(22)
Segmented revenue	8,352	6,685	8,490	783	569	637	591	577	460
Segmented expenses									
Production	2,362	2,186	2,603	400	403	544	226	200	223
Transportation, blending and feedstock	2,291	1,941	2,309	31	48	61	1	2	2
Depletion, depreciation and amortization	3,243	3,465	4,248	509	458	388	205	262	273
Asset retirement obligation accretion	80	66	93	27	35	39	9	12	10
Realized risk management activities	(2)	8	(843)	—	—	—	—	—	—
Gain on acquisition, disposition and revaluation of properties	(35)	(32)	(739)	—	—	—	—	—	—
(Gain) loss from investments	(7)	(320)	6	—	—	—	—	—	—
Total segmented expenses	7,932	7,314	7,677	967	944	1,032	441	476	508
Segmented earnings (loss) before the following	$420	$(629)	$813	$(184)	$(375)	$(395)	$150	$101	$(48)
Non–segmented expenses									
Administration									
Share-based compensation									
Interest and other financing expense									
Unrealized risk management activities									
Foreign exchange (gain) loss									
Total non–segmented expenses									
Earnings (loss) before taxes									
Current income tax recovery									
Deferred income tax expense (recovery)									
Net earnings (loss)									

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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.
Segmented revenue and segmented results include transactions between business segments. Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. 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		
2017	2016	2015	2017	2016	2015	2017	2016	2015	2017	2016	2015
$7,072	$2,657	$2,764	$102	$114	$136	$(82)	$(55)	$(75)	$17,669	$11,098	$13,167
(167)	(24)	(49)	—	—	—	—	—	—	(1,018)	(575)	(804)
6,905	2,633	2,715	102	114	136	(82)	(55)	(75)	16,651	10,523	12,363
2,600	1,292	1,332	16	25	32	(8)	(7)	(8)	5,596	4,099	4,726
679	80	82	—	—	—	(85)	(68)	(75)	2,917	2,003	2,379
1,220	662	562	9	11	12	—	—	—	5,186	4,858	5,483
48	29	31	—	—	—	—	—	—	164	142	173
—	—	—	—	—	—	—	—	—	(2)	8	(843)
(230)	—	—	(114)	(218)	—	—	—	—	(379)	(250)	(739)
—	—	—	(31)	(7)	44	—	—	—	(38)	(327)	50
4,317	2,063	2,007	(120)	(189)	88	(93)	(75)	(83)	13,444	10,533	11,229
$2,588	$570	$708	$222	$303	$48	$11	$20	$8	3,207	(10)	1,134
									319	345	390
									134	355	(46)
									631	383	322
									37	25	374
									(787)	(55)	761
									334	1,053	1,801
									2,873	(1,063)	(667)
									(164)	(618)	(261)
									640	(241)	231
									$2,397	$(204)	$(637)

Capital Expenditures (1)

	2017			2016		
	Net (2) expenditures	Non-cash and fair value changes (2) (3)	Capitalized costs	Net expenditures (proceeds)	Non-cash and fair value changes (3)	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America (4)	$ 160	$ (184)	$ (24)	$ 17	$ (211)	$ (194)
North Sea	—	—	—	—	—	—
Offshore Africa	15	—	15	9	(18)	(9)
Oil Sands Mining and Upgrading	142	117	259	—	—	—
	$ 317	$ (67)	$ 250	$ 26	$ (229)	$ (203)
Property, plant and equipment						
Exploration and Production						
North America	$ 2,815	$ 354	$ 3,169	$ 1,143	$ (36)	$ 1,107
North Sea	160	95	255	126	60	186
Offshore Africa	89	12	101	142	(26)	116
	3,064	461	3,525	1,411	(2)	1,409
Oil Sands Mining and Upgrading (5)	9,592	5,454	15,046	2,718	(23)	2,695
Midstream (6) (7)	80	114	194	(315)	(28)	(343)
Head office	19	—	19	17	—	17
	$ 12,755	$ 6,029	$ 18,784	$ 3,831	$ (53)	$ 3,778

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

(2) Net expenditures on exploration and evaluation assets and property, plant and equipment for the year ended December 31, 2017 exclude non-cash share consideration of $3,818 million issued on the acquisition of AOSP and other assets. This non-cash consideration is included in non-cash and other fair value changes.

(3) Asset retirement obligations, transfers of exploration and evaluation assets, transfers of property, plant and equipment to inventory due to change in use, and other fair value adjustments.

(4) The above noted figures for 2017 do not include the impact of a pre-tax cash gain of $35 million (2016 - $32 million pre-tax cash gain) on the disposition of exploration and evaluation assets.

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

(6) The above noted figures for 2016 do not include a pre-tax cash and non-cash gain of $218 million on the disposition of certain Midstream assets to Inter Pipeline.

(7) The above noted figures for 2017 include the impact of a pre-tax non-cash revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system.

Segmented Assets

	2017	2016
Exploration and Production		
North America	$28,705	$28,892
North Sea	1,854	2,269
Offshore Africa	1,331	1,580
Other	29	29
Oil Sands Mining and Upgrading	40,559	24,852
Midstream	1,279	912
Head office	110	114
	$73,867	$58,648

22. REMUNERATION OF DIRECTORS AND SENIOR MANAGEMENT

Remuneration of Non-Management Directors

	2017	2016	2015
Fees earned	$ 3	$ 2	$ 2

Remuneration of Senior Management (1)

	2017	2016	2015
Salary	$ 3	$ 3	$ 3
Common stock option based awards	10	9	7
Annual incentive plans	5	5	2
Long-term incentive plans	17	15	6
	$ 35	$ 32	$ 18

(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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2017

Principal Documents Exhibits

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”, “m “potential”, “predict”, “should”, “will”, “objective”, “project”, “forecast”, “goal”, “guidance”, “outlook”, “effort”, “seeks”, “sc 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 Oil Sands Mining and Upgrading operations and future expansions, Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the cost of construction and future operations of the North West Redwater bitumen upgrader and refinery, and construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil (“SCO”) that the Company may be reliant upon to transport its products to market, and the "Outlook" section of this MD&A, particularly in reference to the 2018 guidance provided with respect to 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 future production may vary significantly from reserves 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 its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves 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 national, federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company’s assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company’s course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of 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 (loss) from operations, funds flow from operations (previously referred to as 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 (loss) and cash flows from operating activities, as determined in accordance with IFRS, as an indication of the Company’s performance. The non-GAAP measures adjusted net earnings (loss) from operations and funds flow from operations are reconciled to net earnings (loss), as determined in accordance with IFRS, in the “Net Earnings (Loss) and Funds Flow from Operations” section of this MD&A. The non-GAAP measure funds flow from operations is also reconciled to cash flows from operating activities in this section. 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 audited consolidated financial statements and related notes for the year ended December 31, 2017. It should also be read in conjunction with the Company's MD&A for the three months and year ended December 31, 2017, which is incorporated herein by reference. 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 SCO. 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 and feedstock 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 following discussion and analysis refers primarily to the Company's 2017 financial results compared to 2016 and 2015, unless otherwise indicated. In addition, this MD&A details the Company's targeted capital program for 2018. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2017, its Annual Information Form for the year ended December 31, 2017, and its audited consolidated financial statements for the year ended December 31, 2017 is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated February 28, 2018.

Principal Documents Exhibits

DEFINITIONS AND ABBREVIATIONS

AECO	Alberta natural gas reference location
AIF	Annual Information Form
AOSP	Athabasca Oil Sands Project
API	specific gravity measured in degrees on the American Petroleum Institute scale
ARO	asset retirement obligations
bbl	barrel
bbl/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
Bitumen	a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons that are too heavy or thick to flow at reservoir conditions, and recoverable at economic rates using thermal in situ recovery methods
Brent	Dated Brent
C$	Canadian dollars
CAGR	compound annual growth rate
CAPEX	capital expenditures
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
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
Mcfe	thousand cubic feet equivalent
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
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 economic 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, primary heavy crude oil, Pelican Lake heavy crude oil [2], bitumen (thermal oil), SCO and natural gas;
- A large, balanced, diversified, high quality, long life low decline asset base;
- Balance among acquisitions, exploitation and exploration; and
- Balance between sources and terms of debt financing and a strong financial position.

(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 12–17º 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 and bitumen (thermal oil).

Operational discipline, safe, effective and efficient operations, and 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 its growth projects. Additionally, the Company periodically utilizes its risk management hedging program to reduce the risk of volatility in commodity prices and foreign exchange rates and to support 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 and equity financing to selectively acquire properties generating future cash flows in its core areas.

Principal Documents Exhibits

NET EARNINGS (LOSS) AND FUNDS FLOW FROM OPERATIONS

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)		2017	2016	2015
Product sales		$17,669	$11,098	$13,167
Net earnings (loss)		$2,397	$(204)	$(637)
Per common share	– basic	$2.04	$(0.19)	$(0.58)
	– diluted	$2.03	$(0.19)	$(0.58)
Adjusted net earnings (loss) from operations (1)		$1,403	$(669)	$263
Per common share	– basic	$1.19	$(0.61)	$0.24
	– diluted	$1.19	$(0.61)	$0.24
Funds flow from operations (2)		$7,347	$4,293	$5,785
Per common share	– basic	$6.25	$3.90	$5.29
	– diluted	$6.21	$3.89	$5.28
Dividends declared per common share (3)		$1.10	$0.94	$0.92
Total assets		$73,867	$58,648	$59,275
Total long-term liabilities		$35,953	$27,289	$27,299
Net capital expenditures		$17,129	$3,794	$3,853

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings (loss) from operations. The reconciliation “Adjusted Net Earnings (Loss) from Operations” presented in this MD&A, 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 (loss) from operations may not be comparable to similar measures presented by other companies.

(2) Funds flow from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for certain non-cash items and current income tax on disposition of properties. The Company evaluates its performance based on funds flow from operations. The Company considers funds 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 “Funds Flow from Operations, as Reconciled to Net Earnings (Loss)” presented in this MD&A, includes certain non-cash items that are disclosed in the Company's financial results as presented in the Company's consolidated Statements of Cash Flows. Funds flow from operations may not be comparable to similar measures presented by other companies.

Funds flow from operations can also be derived by adjusting the GAAP measure Cash Flows from Operating Activities presented in the Company's consolidated Statements of Cash Flows for the net change in non-cash working capital, and abandonment and other expenditures. Accordingly, the Company has provided a second reconciliation, "Funds Flow from Operations, as Reconciled to Cash Flows from Operating Activities" in this MD&A.

(3) On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share, beginning with the dividend payable on April 1, 2018. On March 1, 2017, the Board of Directors approved an increase in the quarterly dividend to $0.275 per common share, beginning with the dividend payable on April 1, 2017. On November 2, 2016, the Board of Directors approved an increase in the quarterly dividend to $0.25 per common share, beginning with the dividend payable on January 1, 2017. On March 2, 2016, the Board of Directors declared a quarterly dividend of $0.23 per common share, beginning with the dividend payable on April 1, 2016. On March 4, 2015 the Board of Directors declared a quarterly dividend of $0.23 per common share, beginning with the dividend payable on April 1, 2015.

Adjusted Net Earnings (Loss) from Operations

($ millions)	2017	2016	2015
Net earnings (loss) as reported	$2,397	$(204)	$(637)
Share-based compensation, net of tax (1)	134	355	(46)
Unrealized risk management loss, net of tax (2)	33	21	275
Unrealized foreign exchange (gain) loss, net of tax (3)	(821)	(93)	858
(Gain) loss from investments, net of tax (4) (5)	(11)	(299)	55
Gain on acquisition, disposition and revaluation of properties, net of tax (6)	(339)	(241)	(663)
Derecognition of exploration and evaluation assets, net of tax (7)	—	13	70
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (8)	10	(221)	351
Adjusted net earnings (loss) from operations	$1,403	$(669)	$263

(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 (loss) or are charged to (recovered from) Oil Sands Mining and Upgrading.

(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 (loss). 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, natural gas and foreign exchange.

(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 (loss).

(4) The Company's investment in the 50% owned North West Redwater Partnership ("Redwater Partnership") is accounted for using the equity method of accounting. Included in the non-cash (gain) loss from investments is the Company's pro rata share of the Redwater Partnership's accounting (gain) loss.

(5) The Company's investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("Inter Pipeline") have been accounted for at fair value through profit and loss and are remeasured each period with changes in fair value recognized in net earnings (loss).

(6) During 2017, the Company recorded a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system. Additionally, the Company recorded a pre and after-tax gain of $230 million on the acquisition of a direct and indirect 70% interest in AOSP and other assets from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), and a pre-tax gain of $35 million ($26 million after-tax) on the disposition of certain exploration and evaluation assets in the North America segment. During 2016, the Company recorded a pre and after-tax gain of $218 million on the disposition of Midstream property, plant and equipment. Additionally, the Company recorded a pre-tax gain of $32 million ($23 million after-tax) on the disposition of certain exploration and evaluation assets. During 2015, the Company recorded a pre-tax gain of $739 million ($663 million after-tax) related to the disposition of a number of North America royalty income assets and crude oil and natural gas properties.

(7) During 2016, in connection with the Company's notice of withdrawal from Block CI-12 in Côte d'Ivoire, Offshore Africa, the Company derecognized $18 million ($13 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense. During 2015, in connection with the Company's notice of withdrawal from Block CI-514 in Côte d'Ivoire, Offshore Africa, the Company derecognized $96 million ($70 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense.

(8) 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 (loss) during the period the legislation is substantively enacted. During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $10 million.

During 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. In addition, the UK government also enacted tax rate reductions relating to Petroleum Revenue Tax (“PRT”), resulting in a decrease in the Company’s net deferred income tax liability of $114 million.
During 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $579 million. In addition, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and PRT, and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company’s net deferred income tax liability of $228 million.

Funds Flow from Operations, as Reconciled to Net Earnings(Loss) [1]

($ millions)	2017	2016	2015
Net earnings (loss)	$2,397	$(204)	$(637)
Non-cash items:			
Depletion, depreciation and amortization	5,186	4,858	5,483
Share-based compensation	134	355	(46)
Asset retirement obligation accretion	164	142	173
Unrealized risk management loss	37	25	374
Unrealized foreign exchange (gain) loss	(821)	(93)	858
(Gain) loss from investments	(11)	(299)	55
Deferred income tax expense (recovery)	640	(241)	231
Gain on acquisition, disposition and revaluation of properties	(379)	(250)	(739)
Current income tax on disposition of properties	—	—	33
Funds flow from operations	$7,347	$4,293	$5,785

(1) Funds flow from operations was previously referred to as cash flow from operations.

Funds Flow from Operations, as Reconciled to Cash Flows from Operating Activities

($ millions)	2017	2016	2015
Cash flows from operating activities	$7,262	$3,452	$5,632
Net change in non-cash working capital	(299)	542	(239)
Abandonment expenditures	274	267	370
Other	110	32	22
Funds flow from operations	$7,347	$4,293	$5,785

SUMMARY OF CONSOLIDATED NET EARNINGS (LOSS) AND FUNDS FLOW FROM OPERATIONS

For 2017, the Company reported net earnings of $2,397 million compared with a net loss of $204 million for 2016 (2015 – $637 million net loss). Net earnings for 2017 included net after-tax income of $994 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of realized foreign exchange losses and gains on repayment of long-term debt, (gain) loss from investments, gain on acquisition, disposition and revaluation of properties, derecognition of exploration and evaluation assets and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities (2016 – $465 million after-tax income; 2015 – $900 million after-tax expenses). Excluding these items, the adjusted net earnings from operations for 2017 was $1,403 million compared with an adjusted net loss of $669 million for 2016 (2015 – $263 million adjusted net earnings).

The increase in adjusted net earnings (loss) for 2017 from 2016 was primarily due to:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment, due to volumes associated with both the acquisition of AOSP and new Phase 2B and Phase 3 sales volumes at Horizon;
- higher crude oil and NGLs and natural gas netbacks in the Exploration and Production segments; and
- higher realized SCO prices in the Oil Sands Mining and Upgrading segment;

partially offset by:

- higher depletion, depreciation and amortization;
- higher interest and financing expense; and
- the strengthening of the Canadian dollar relative to the US dollar.

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

Funds flow from operations for 2017 increased to $7,347 million ($6.25 per common share) from $4,293 million for 2016 ($3.90 per common share) (2015 – $5,785 million; $5.29 per common share). The increase in funds flow from operations for 2017 from 2016 was primarily due to the factors noted above relating to the increase in adjusted net earnings (loss), partially offset by the impact of cash taxes.

In the Company's Exploration and Production activities, the 2017 average sales price per bbl of crude oil and NGLs increased 32% to average $48.57 per bbl from $36.93 per bbl in 2016 (2015 – $41.13 per bbl), and the 2017 average natural gas price increased 19% to average $2.76 per Mcf from $2.32 per Mcf in 2016 (2015 – $3.16 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2017 average SCO sales price increased 9% to average $63.98 per bbl from $58.59 per bbl in 2016 (2015 – $61.39 per bbl).

Total production of crude oil and NGLs before royalties for 2017 increased 31% to average 685,236 bbl/d from 523,873 bbl/d in 2016 (2015 – 564,188 bbl/d). The increase in crude oil and NGLs production from 2016 was primarily due to acquisitions completed in 2017 and new Phase 2B and Phase 3 production at Horizon.

Total natural gas production before royalties for 2017 decreased 2% to average 1,662 MMcf/d from 1,691 MMcf/d in 2016 (2015 – 1,726 MMcf/d). The decrease in natural gas production from 2016 primarily reflected lower production in North America due to the continued impact of reliability issues at a third party processing facility and shut-in production volumes related to low natural gas prices.

Total crude oil and NGLs and natural gas production volumes before royalties for 2017 increased 19% to average 962,264 BOE/d from 805,782 BOE/d in 2016 (2015 – 851,901 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)

2017	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales	$17,669	$5,323	$4,547	$3,927	$3,872
Net earnings (loss)	$2,397	$396	$684	$1,072	$245
Net earnings (loss) per common share					
– basic	$2.04	$0.32	$0.56	$0.93	$0.22
– diluted	$2.03	$0.32	$0.56	$0.93	$0.22

($ millions, except per common share amounts)

2016	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales	$11,098	$3,672	$2,477	$2,686	$2,263
Net earnings (loss)	$(204)	$566	$(326)	$(339)	$(105)
Net earnings (loss) per common share					
– basic	$(0.19)	$0.51	$(0.29)	$(0.31)	$(0.10)
– diluted	$(0.19)	$0.51	$(0.29)	$(0.31)	$(0.10)

Principal Documents Exhibits

Volatility in the quarterly net earnings (loss) over the eight most recently completed quarters was primarily due to:
Crude oil pricing – Fluctuating global supply/demand including crude oil production levels from the Organization of the Petroleum Exporting Countries ("OPEC") and its impact on world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the WCS Heavy Differential 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, third party pipeline maintenance and the impact of 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, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, fluctuations in the Company's drilling program in North America, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, new production from Horizon Phase 2B and Phase 3, the impact of turnarounds at Horizon and pitstops at AOSP, shut-in production due to low commodity prices, and the impact of the drilling program in Côte d'Ivoire in Offshore Africa. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.

Natural gas sales volumes – Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, natural decline rates, an outage at a third party processing facility, shut-in production due to third party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices, and the impact and timing of acquisitions.
Production expense – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production, the impact of seasonal costs that are dependent on weather, cost optimizations across all segments, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, turnarounds at Horizon and pitstops at AOSP, and maintenance activities in the International segments.
Depletion, depreciation and amortization – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, 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, fluctuations in International sales volumes subject to higher depletion rates, fluctuations in depletion, depreciation, and amortization expense in the North Sea due to the cessation of production at the Ninian North platform in 2017, and the impact of turnarounds 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 – Fluctuations in the Canadian dollar relative to the US dollar, which 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 were 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.
Gain on acquisition, disposition and revaluation of properties and gain/loss on investments – Fluctuations due to the recognition of gains on the acquisition of AOSP and other assets, the disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity (gain) loss in North West Redwater.

BUSINESS ENVIRONMENT

(Yearly average)	2017	2016	2015
WTI benchmark price (US$/bbl)	$50.93	$43.37	$48.76
Dated Brent benchmark price (US$/bbl)	$54.38	$43.96	$52.40
WCS blend differential from WTI (US$/bbl)	$11.97	$13.91	$13.51
SCO price (US$/bbl)	$52.20	$43.94	$48.59
Condensate benchmark price (US$/bbl)	$51.65	$42.51	$47.34
NYMEX benchmark price (US$/MMBtu)	$3.11	$2.45	$2.67
AECO benchmark price (C$/GJ)	$2.30	$1.98	$2.62
US/Canadian dollar average exchange rate (US$)	$0.7701	$0.7548	$0.7820
US/Canadian dollar year end exchange rate (US$)	$0.7988	$0.7448	$0.7225

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 highly sensitive to fluctuations in foreign exchange rates. During 2017, product revenue continued to be impacted by the volatility in the Canadian dollar as the Canadian dollar sales price the Company received for its crude oil and natural gas sales is based on US dollar denominated benchmarks. The average value of the Canadian dollar in relation to the US dollar fluctuated throughout 2017, with a high of approximately US$0.82 in September 2017 and a low of approximately US$0.73 in May 2017.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$50.93 per bbl for 2017, an increase of 17% from US$43.37 per bbl for 2016 (2015 – US$48.76 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$54.38 per bbl for 2017, an increase of 24% from US$43.96 per bbl for 2016 (2015 – US$52.40 per bbl).

WTI and Brent pricing for 2017 increased from 2016 primarily due to declines in global crude oil inventories as a result of OPEC's adherence to previously announced production cuts, together with larger than anticipated increases in global demand for crude oil.

The WCS Heavy Differential averaged US$11.97 for 2017, a decrease of 14% from US$13.91 for 2016 (2015 – US$13.51). The WCS Heavy Differential reflects US Gulf Coast pricing, adjusted for transportation costs. Fluctuations in the WCS Heavy Differential reflected seasonal supply and demand factors and changes in transportation logistics. Subsequent to December 31, 2017 the WCS Heavy Differential widened due to third party pipeline outages.

The SCO price averaged US$52.20 per bbl for 2017, an increase of 19% from US$43.94 per bbl for 2016 (2015 – US$48.59 per bbl). The increase in SCO pricing for 2017 from 2016 was primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US$3.11 per MMBtu for 2017, an increase of 27% from US$2.45 per MMBtu for 2016 (2015 – US$2.67 per MMBtu). AECO natural gas prices averaged $2.30 per GJ for 2017, an increase of 16% from $1.98 per GJ for 2016 (2015 – $2.62 per GJ).

The increase in natural gas prices for 2017 compared with 2016 reflected the rebalancing of natural gas storage inventory to historically normal levels.

ANALYSIS OF CHANGES IN PRODUCT SALES

($ millions)	2015	Changes due to Volumes	Prices	Other	2016	Changes due to Volumes	Prices	Other	2017
North America									
Crude oil and NGLs	$7,452	$(937)	$(690)	$108	$5,933	$135	$1,755	$(168)	$7,655
Natural gas	1,770	(40)	(454)	—	1,276	(20)	250	—	1,506
	9,222	(977)	(1,144)	108	7,209	115	2,005	(168)	9,161
North Sea									
Crude oil and NGLs	512	54	(78)	(10)	478	63	130	(5)	666
Natural gas	126	9	(43)	—	92	3	23	—	118
	638	63	(121)	(10)	570	66	153	(5)	784
Offshore Africa									
Crude oil and NGLs	389	224	(79)	(2)	532	(70)	103	14	579
Natural gas	93	17	(39)	—	71	(22)	4	—	53
	482	241	(118)	(2)	603	(92)	107	14	632
Subtotal									
Crude oil and NGLs	8,353	(659)	(847)	96	6,943	128	1,988	(159)	8,900
Natural gas	1,989	(14)	(536)	—	1,439	(39)	277	—	1,677
	10,342	(673)	(1,383)	96	8,382	89	2,265	(159)	10,577
Oil Sands Mining and Upgrading	2,764	17	(126)	2	2,657	3,827	561	27	7,072
Midstream	136	—	—	(22)	114	—	—	(12)	102
Intersegment eliminations and other (1)	(75)	—	—	20	(55)	—	—	(27)	(82)
Total	$13,167	$(656)	$(1,509)	$96	$11,098	$3,916	$2,826	$(171)	$17,669

(1) Eliminates internal transportation and electricity charges.

Product sales increased 59% to $17,669 million for 2017 from $11,098 million for 2016 (2015 – $13,167 million). The increase was primarily due to higher SCO sales volumes in the Oil Sands Mining and Upgrading segment and higher realized prices in all business segments.

For 2017, 8% of the Company's crude oil and NGLs and natural gas product sales were generated outside of North America (2016 – 11%; 2015 – 9%). North Sea accounted for 4% of crude oil and NGLs and natural gas product sales for 2017 (2016 – 5%; 2015 – 5%), and Offshore Africa accounted for 4% of crude oil and NGLs and natural gas product sales for 2017 (2016 – 6%; 2015 – 4%).

DAILY PRODUCTION, before royalties

	2017	2016	2015
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	359,449	350,958	399,982
Oil Sands Mining and Upgrading - Horizon [1]	170,089	123,265	122,911
Oil Sands Mining and Upgrading - AOSP	111,937	—	—
North Sea	23,426	23,554	22,216
Offshore Africa	20,335	26,096	19,079
	685,236	523,873	564,188
Natural gas (MMcf/d)			
North America	1,601	1,622	1,663
North Sea	39	38	36
Offshore Africa	22	31	27
	1,662	1,691	1,726
Total barrels of oil equivalent (BOE/d)	962,264	805,782	851,901
Product mix			
Light and medium crude oil and NGLs	14%	17%	16%
Pelican Lake heavy crude oil	6%	6%	6%
Primary heavy crude oil	10%	13%	15%
Bitumen (thermal oil)	12%	14%	15%
Synthetic crude oil [1]	29%	15%	14%
Natural gas	29%	35%	34%
Percentage of gross revenue [1] [2] (excluding Midstream revenue)			
Crude oil and NGLs	90%	85%	82%
Natural gas	10%	15%	18%

(1) 2017 SCO production before royalties excludes 651 bbl/d of SCO consumed internally as diesel (2016 - 1,966 bbl/d, 2015 - 2,122 bbl/d).

(2) Net of blending costs and excluding risk management activities.

DAILY PRODUCTION, net of royalties

	2017	2016	2015
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	312,297	311,059	350,451
Oil Sands Mining and Upgrading - Horizon	167,248	122,258	121,208
Oil Sands Mining and Upgrading - AOSP	107,189	—	—
North Sea	23,382	23,497	22,164
Offshore Africa	19,124	24,995	18,209
	629,240	481,809	512,032
Natural gas (MMcf/d)			
North America	1,528	1,559	1,606
North Sea	39	38	36
Offshore Africa	20	30	25
	1,587	1,627	1,667
Total barrels of oil equivalent (BOE/d)	893,702	752,974	789,799

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 2017 production averaged 962,264 BOE/d, a 19% increase from 805,782 BOE/d in 2016 (2015 – 851,901 BOE/d).

Total production of crude oil and NGLs for 2017 increased 31% to 685,236 bbl/d from 523,873 bbl/d for 2016 (2015 – 564,188 bbl/d). The increase in crude oil and NGLs production from 2016 was primarily due to acquisitions completed in 2017 and new Phase 2B and Phase 3 production at Horizon. Crude oil and NGLs production for 2017 was within the Company’s previously issued guidance of 663,000 to 717,000 bbl/d.

Natural gas production accounted for 29% of the Company's total production in 2017 on a BOE basis. Natural gas production for 2017 decreased 2% to 1,662 MMcf/d from 1,691 MMcf/d for 2016 (2015 – 1,726 MMcf/d). Natural gas production continued to be impacted by shut-in production volumes due to low natural gas prices and the impact of reliability issues at a third party facility. As a result of continued integrity issues, capacity at this facility has now been reduced to a one train operation. Natural gas production for 2017 was within the Company’s previously issued guidance of 1,655 to 1,705 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production for 2017 increased 2% to average 359,449 bbl/d from 350,958 bbl/d for 2016 (2015 – 399,982 bbl/d). The increase in production from 2016 was primarily due to acquisitions completed in 2017.

Natural gas production for 2017 of 1,601 MMcf/d was comparable with 1,622 MMcf/d for 2016 (2015 – 1,663 MMcf/d). Natural gas production continued to be impacted by shut-in production volumes due to low natural gas prices and the impact of reliability issues at a third party facility. As a result of continued integrity issues, capacity at this facility has now been reduced to a one train operation.

Horizon

Horizon SCO production for 2017 increased 38% to 170,089 bbl/d from 123,265 bbl/d for 2016 (2015 – 122,911 bbl/d). The increase in 2017 production primarily reflected new Phase 2B and Phase 3 production.

Athabasca Oil Sands Project

AOSP annualized SCO production for 2017 averaged 111,937 bbl/d, reflecting the Company's direct and indirect 70% interest in the project acquired in May 2017.

North Sea

North Sea crude oil production for 2017 of 23,426 bbl/d was comparable with 23,554 bbl/d for 2016 (2015 – 22,216 bbl/d).

Offshore Africa

Offshore Africa crude oil production for 2017 decreased 22% to 20,335 bbl/d from 26,096 bbl/d for 2016 (2015 – 19,079 bbl/d). Production volumes decreased from 2016 primarily due to natural field declines.

CORPORATE PRODUCTION GUIDANCE FOR 2018

The Company targets production levels in 2018 to average between 815,000 bbl/d and 885,000 bbl/d of crude oil and NGLs and between 1,650 MMcf/d and 1,710 MMcf/d of natural gas.

International 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 in the International business segments on crude oil volumes that were stored in various storage facilities or FPSOs, as follows:

(bbl)	2017	2016	2015
North Sea	—	987,316	835,806
Offshore Africa	121,936	1,126,999	1,271,170
	121,936	2,114,315	2,106,976

Principal Documents Exhibits

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	2017	2016	2015
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	$48.57	$36.93	$41.13
Transportation	2.80	2.61	2.60
Realized sales price, net of transportation	45.77	34.32	38.53
Royalties	5.24	3.40	4.30
Production expense	14.89	14.10	15.74
Netback	$25.64	$16.82	$18.49
Natural gas ($/Mcf) (1)			
Sales price (2)	$2.76	$2.32	$3.16
Transportation	0.39	0.33	0.38
Realized sales price, net of transportation	2.37	1.99	2.78
Royalties	0.11	0.09	0.10
Production expense	1.27	1.18	1.34
Netback	$0.99	$0.72	$1.34
Barrels of oil equivalent ($/BOE) (1)			
Sales price (2)	$35.54	$27.58	$32.60
Transportation	2.66	2.44	2.56
Realized sales price, net of transportation	32.88	25.14	30.04
Royalties	3.40	2.21	2.85
Production expense	11.95	11.18	12.70
Netback	$17.53	$11.75	$14.49

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	2017	2016	2015
Crude oil and NGLs ($/bbl) (1) (2)			
North America	$45.85	$34.31	$38.96
North Sea	$69.43	$55.91	$65.13
Offshore Africa	$67.15	$54.96	$63.13
Company average	$48.57	$36.93	$41.13
Natural gas ($/Mcf) (1) (2)			
North America	$2.58	$2.15	$2.91
North Sea	$8.24	$6.62	$9.66
Offshore Africa	$6.57	$6.13	$9.53
Company average	$2.76	$2.32	$3.16
Company average ($/BOE) (1) (2)	$35.54	$27.58	$32.60

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

Realized crude oil and NGLs prices increased 32% to average $48.57 per bbl for 2017 from $36.93 per bbl for 2016 (2015 – $41.13 per bbl), primarily due to higher WTI and Brent benchmark pricing.

The Company's realized natural gas price increased 19% to average $2.76 per Mcf for 2017 from $2.32 per Mcf for 2016 (2015 – $3.16 per Mcf). The increase in 2017 reflected the rebalancing of natural gas storage inventory to historically normal levels.

North America

North America realized crude oil prices increased 34% to average $45.85 per bbl for 2017 from $34.31 per bbl for 2016 (2015 – $38.96 per bbl), primarily due to higher WTI benchmark pricing.

North America realized natural gas prices increased 20% to average $2.58 per Mcf for 2017 from $2.15 per Mcf for 2016 (2015 – $2.91 per Mcf). The increase reflected the rebalancing of natural gas storage inventory to historically normal 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 and bitumen (thermal oil) conversion capacity. During 2017, the Company contributed approximately 195,800 bbl/d of heavy crude oil blends to the WCS stream.

The Company has 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 project has received regulatory approval and is awaiting final permits. Pipeline construction is scheduled to begin in the latter half of 2018 with an expected in-service date late in 2020.

The Company has also entered into a 20 year transportation agreement to ship 175,000 bbl/d of crude oil on the proposed Trans Canada Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast. The project received a Presidential Permit in March 2017 and the regulatory process of finalizing route alterations and shipper commitments is ongoing. The pipeline has an expected in-service date in 2021.

In November 2017, the Energy East Pipeline Limited Partnership terminated the Energy East Pipeline project and the Company's agreement to transport 80,000 bbl/d was cancelled.

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

(Yearly average)	2017	2016	2015
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	$47.78	$37.72	$41.88
Pelican Lake heavy crude oil ($/bbl)	$48.30	$36.03	$41.09
Primary heavy crude oil ($/bbl)	$46.88	$34.73	$40.71
Bitumen (thermal oil) ($/bbl)	$42.49	$30.47	$34.37
Natural gas ($/Mcf)	$2.58	$2.15	$2.91

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

North Sea

North Sea realized crude oil prices increased 24% to average $69.43 per bbl for 2017 from $55.91 per bbl for 2016 (2015 – $65.13 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. The increase in realized crude oil prices in 2017 reflected higher prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 22% to average $67.15 per bbl for 2017 from $54.96 per bbl for 2016 (2015 – $63.13 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. The increase in realized crude oil prices in 2017 reflected higher prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	2017	2016	2015
Crude oil and NGLs ($/bbl) (1)			
North America	$5.69	$3.69	$4.57
North Sea	$0.13	$0.13	$0.14
Offshore Africa	$4.13	$2.31	$2.87
Company average	$5.24	$3.40	$4.30
Natural gas ($/Mcf) (1)			
North America	$0.11	$0.08	$0.09
Offshore Africa	$0.76	$0.28	$0.46
Company average	$0.11	$0.09	$0.10
Company average ($/BOE) (1)	$3.40	$2.21	$2.85

(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").

North America crude oil and natural gas royalties for 2017 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 13% of product sales for 2017 compared with 12% of product sales for 2016 (2015 – 13%). The increase in royalties for 2017 from 2016 was primarily due to higher realized crude oil prices during 2017. North America crude oil and NGLs royalties per bbl are anticipated to average 10% to 12% of product sales for 2018.

Natural gas royalties averaged approximately 5% of product sales for 2017 compared with 4% of product sales for 2016 (2015 – 4%). The increase in royalties for 2017 from 2016 was primarily due to higher realized natural gas prices. North America natural gas royalties are anticipated to average 4% to 6% of product sales for 2018.

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 7% for 2017 compared with 4% of product sales for 2016 (2015 – 5%). Royalties as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 7% to 9% of product sales for 2018.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	2017	2016	2015
Crude oil and NGLs ($/bbl) (1)			
North America	$12.71	$11.89	$12.51
North Sea	$36.60	$42.47	$63.67
Offshore Africa	$24.07	$18.48	$33.32
Company average	$14.89	$14.10	$15.74
Natural gas ($/Mcf) (1)			
North America	$1.19	$1.12	$1.27
North Sea	$3.37	$3.09	$4.41
Offshore Africa	$2.90	$1.79	$1.76
Company average	$1.27	$1.18	$1.34
Company average ($/BOE) (1)	$11.95	$11.18	$12.70

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

North America

North America crude oil and NGLs production expense for 2017 increased 7% to $12.71 per bbl from $11.89 per bbl for 2016 (2015 – $12.51 per bbl). The Company continues to focus on cost control and achieving efficiencies on acquired assets and across the entire asset base. The increase in crude oil and NGLs production expense for 2017 from 2016 reflected higher maintenance, trucking and other service costs. Crude oil and NGLs production expense for 2017 was within annual guidance of $11.50 to $13.50 per bbl. North America crude oil and NGLs production expense is anticipated to average $11.50 to $13.50 per bbl for 2018.

North America natural gas production expense for 2017 increased 6% to $1.19 per Mcf from $1.12 per Mcf for 2016 (2015 – $1.27 per Mcf). The Company continues to focus on cost control and achieving efficiencies on acquired assets and across the entire asset base. The increase in natural gas production expense for 2017 from 2016 reflected higher maintenance and other service costs. Natural gas production expense for 2017 was within annual guidance of $1.00 to $1.20 per Mcf. North America natural gas production expense is anticipated to average $1.00 to $1.20 per Mcf for 2018.

North Sea

North Sea crude oil production expense for 2017 decreased 14% to $36.60 per bbl from $42.47 per bbl for 2016 (2015 – $63.67 per bbl). The decrease for 2017 from 2016 reflected the Company's continuous focus on cost control, efficiencies and production optimization. Production expense also reflected fluctuations in the Canadian dollar and the UK pound sterling. Crude oil and NGLs production expense for 2017 was slightly above annual guidance of $33.00 to $36.00 per bbl, reflecting the impact of lower volumes on a relatively fixed cost base due to temporary unplanned shut-ins. North Sea crude oil production expense guidance is anticipated to average $36.00 to $39.00 per bbl for 2018.

Offshore Africa

Offshore Africa crude oil production expense for 2017 increased 30% to $24.07 per bbl from $18.48 per bbl for 2016 (2015 – $33.32 per bbl). Total Offshore Africa crude oil production expense for 2017 primarily reflected the timing of liftings from various fields, including the Olowi field, which have different cost structures, fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar.

On a standalone basis, Offshore Africa production expense for 2017 related to the Baobab and Espoir fields in Côte d'Ivoire was $12.41 per bbl and was within annual guidance of $10.50 to $12.50 per bbl. Offshore Africa production expense related to Côte d'Ivoire is anticipated to average $11.00 to $13.00 per bbl for 2018.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)	2017	2016	2015
North America	$3,243	$3,465	$4,248
North Sea	509	458	388
Offshore Africa	205	262	273
Expense	$3,957	$4,185	$4,909
$/BOE [(1)]	$15.82	$16.79	$18.50

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

Depletion, depreciation and amortization in 2017 decreased 6% to $15.82 per BOE from $16.79 per BOE for 2016 (2015 – $18.50 per BOE). The decrease in depletion, depreciation and amortization expense per BOE for 2017 from 2016 was primarily due to a lower depletable base in North America, partially offset by additional depletion, depreciation and amortization in the North Sea related to the abandonment of the Ninian North platform.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)	2017	2016	2015
North America	$80	$66	$93
North Sea	27	35	39
Offshore Africa	9	12	10
Expense	$116	$113	$142
$/BOE [(1)]	$0.46	$0.45	$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.

Asset retirement obligation accretion expense for 2017 of $0.46 per BOE was comparable with $0.45 per BOE for 2016 (2015 – $0.54 per BOE).

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

On May 31, 2017 the Company completed the acquisition of a direct and indirect 70% interest in AOSP, including a 70% interest in the mining and extraction operations north of Fort McMurray, Alberta and 70% of the Scotford Upgrader and Quest Carbon Capture and Storage ("CCS") project. The acquisition strengthened the Company's portfolio of long life no decline synthetic crude oil assets. Effective May 31, 2017, the Oil Sands Mining and Upgrading segment of this MD&A reflects the mining, extraction and upgrading operations at both Horizon and AOSP.

The Company continues to focus on reliable and efficient operations. The Oil Sands Mining and Upgrading segment achieved production during 2017 averaging 282,026 bbl/d following the addition of new production volumes from the acquisition of and successful integration of the Company's interest in AOSP as well as new Phase 2B and Phase 3 production at Horizon.

Horizon Operations Update

Horizon SCO production averaged 170,089 bbl/d during 2017, reflecting new Phase 2B and Phase 3 production. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, together with additional production from new Phase 2B and Phase 3, adjusted cash production costs averaged $21.46 per bbl.

The Horizon Phase 3 expansion was completed on schedule and within budget. Phase 3 activities included the expansion tie-in and commissioning of the production plant. SCO production for the month of December averaged approximately 247,200 bbl/d, reflecting new Phase 3 production.

AOSP Operations Update

Annualized AOSP SCO production averaged 111,937 bbl/d during 2017, reflecting high reliability of operations. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability of AOSP operations, cash production costs averaged $26.34 per bbl.

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

($/bbl) (1)	2017	2016	2015
SCO sales price (2) (3)	$63.98	$58.59	$61.39
Bitumen value for royalty purposes (4)	$41.05	$27.57	$32.14
Bitumen royalties (5)	$1.64	$0.54	$1.08
Transportation	$1.54	$1.77	$1.81

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

(2) The realized sales price for 2017 reflects the weighted average price of Horizon SCO and AOSP SCO while the realized sales price for 2016 and 2015 reflects the Horizon SCO price only. The Horizon realized sales price reflects a premium light sweet SCO compared to the blend at AOSP.

(3) Net of blending and feedstock costs.

(4) Calculated as the annual average of the bitumen valuation methodology price.

(5) Calculated based on bitumen royalties expensed during the year; divided by the corresponding SCO sales volumes.

The realized SCO sales price for the Oil Sands Mining and Upgrading segment averaged $63.98 per bbl for 2017, an increase of 9% compared with $58.59 per bbl for 2016 (2015 – $61.39 per bbl). The increase in SCO pricing for 2017 compared to 2016 primarily reflected higher WTI benchmark pricing, together with the impact of new AOSP SCO sales volumes.

The SCO sales price for 2017 reflected an average realized price at Horizon of $67.74 per bbl and an average realized price at AOSP of $58.30 per bbl for 2017.

Principal Documents Exhibits

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 audited consolidated financial statements.

($ millions)	2017	2016	2015
Cash production costs	$2,600	$1,292	$1,332
Less: costs incurred during turnaround periods	(216)	(151)	(45)
Adjusted cash production costs	$2,384	$1,141	$1,287
Adjusted cash production costs, excluding natural gas costs	$2,239	$1,057	$1,212
Adjusted natural gas costs	145	84	75
Adjusted cash production costs	$2,384	$1,141	$1,287
($/bbl) (1)	2017	2016	2015
Adjusted cash production costs, excluding natural gas costs	$21.98	$23.36	$26.95
Adjusted natural gas costs	1.42	1.84	1.66
Adjusted cash production costs	$23.40	$25.20	$28.61
Sales (bbl/d)	279,084	123,652	123,231

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

Adjusted cash production costs for 2017 decreased 7% to $23.40 per bbl from $25.20 per bbl for 2016 (2015 – $28.61 per bbl). The decrease in adjusted cash production costs per barrel for 2017 from 2016 primarily reflected the Company's continuous focus on cost control and efficiencies and high utilization rates and reliability, together with additional capacity from new Phase 2B and Phase 3 production at Horizon, partially offset by the impact of the acquisition of AOSP. For 2018, Oil Sands Mining and Upgrading cash production costs, including turnaround costs, are anticipated to average $22.50 to $26.50 per bbl.

Horizon adjusted cash production costs for 2017 decreased 15% to $21.46 per bbl from $25.20 per bbl for 2016 (2015 – $28.61 per bbl). Cash production costs of $24.98 per bbl for 2017, including turnaround costs, were within the Company's previously issued guidance of $24.00 to $27.00 per bbl.

AOSP annualized cash production costs for 2017 averaged $26.34 per bbl, reflecting high reliability of operations. Cash production costs for 2017 were below the Company's previously issued guidance of $27.00 to $31.00 per bbl.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	2017	2016	2015
Depletion, depreciation and amortization	$1,220	$662	$562
Less: depreciation incurred during turnaround period	(213)	(99)	(5)
Adjusted depletion, depreciation and amortization	$1,007	$563	$557
$/bbl (1)	$9.89	$12.43	$12.37

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

Adjusted depletion, depreciation and amortization expense per barrel for 2017 decreased 20% to $9.89 per bbl from $12.43 per bbl for 2016 (2015 – $12.37 per bbl), primarily due to the impact of AOSP, which has a lower depletion rate.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	2017	2016	2015
Expense	$48	$29	$31
$/bbl (1)	$0.47	$0.64	$0.69

(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. The increase in asset retirement obligation accretion expense in 2017 reflected the acquisition of AOSP.

Asset retirement obligation accretion expense per barrel for 2017 decreased 27% to $0.47 per bbl from $0.64 per bbl for 2016, reflecting added sales volumes from AOSP (2015 – $0.69 per bbl).

MIDSTREAM

($ millions)	2017	2016	2015
Revenue	$102	$114	$136
Production expense	16	25	32
Midstream cash flow	86	89	104
Depreciation	9	11	12
Equity (gain) loss from Redwater Partnership	(31)	(7)	44
Gain on disposition and revaluation of properties	(114)	(218)	—
Segment earnings before taxes	$222	$303	$48

During 2017, the Company recorded a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system. During 2016, the Company disposed of its interest in the Cold Lake Pipeline, including $321 million of property, plant and equipment, for total net consideration of $539 million, resulting in a pre and after-tax gain of $218 million. Total net consideration was comprised of $349 million in cash, together with $190 million of non-cash share consideration of approximately 6.4 million common shares of Inter Pipeline with a value of $29.57 per common share, determined as of the closing date.

With the Company's disposal of its interest in the Cold Lake Pipeline, the Company's Midstream assets now consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose and the Company's 50% interest in the Redwater Partnership. Approximately 50% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO and Pelican Lake pipelines. 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.

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. The facility capital cost (“FCC”) budget for the Project is currently estimated to be $9,500 million with project completion targeted for third quarter 2018. Productivity challenges during construction have continued to result in upward budgetary pressures that may result in a further increase in FCC of up to 2%. During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. To December 31, 2017, each party has provided $411 million of subordinated debt, together with accrued interest thereon of $99 million, for a Company total of $510 million. Any additional subordinated debt financing is not expected to be significant.

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

During 2017, Redwater Partnership issued $750 million of 2.80% series J senior secured bonds due June 2027 and $750 million of 3.65% series K senior secured bonds due June 2035.
During 2016, Redwater Partnership issued $550 million of 4.25% series F senior secured bonds due June 2029, $500 million of 4.75% series G senior secured bonds due June 2037, $500 million of 4.15% series H senior secured bonds due June 2033, and $500 million of 4.35% series I senior secured bonds due January 2039.
As at December 31, 2017, Redwater Partnership had additional borrowings of $1,870 million under its secured $3,500 million syndicated credit facility, maturing June 2018. Subsequent to December 31, 2017, Redwater Partnership extended $2,000 million of the $3,500 million revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	2017	2016	2015
Expense	$319	$345	$390
$/BOE (1)	$0.91	$1.17	$1.26

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

Administration expense per BOE for 2017 decreased 22% to $0.91 per BOE from $1.17 per BOE for 2016 (2015 – $1.26 per BOE). Administration expense per BOE decreased for 2017 from 2016 primarily due to higher overhead recoveries and higher sales volumes.

SHARE-BASED COMPENSATION

($ millions)	2017	2016	2015
Expense (recovery)	$134	$355	$(46)

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 Company recorded a $134 million share-based compensation expense for the year ended December 31, 2017, primarily as a result of remeasurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period and changes in the Company’s share price. Included within share-based compensation expense for 2017 was $5 million (2016 – $nil; 2015 – $nil) related to performance share units granted to certain executive employees. For 2017, the Company charged $14 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (2016 – $67 million costs charged, 2015 – $10 million costs recovered).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	2017	2016	2015
Expense, gross	$713	$616	$566
Less: capitalized interest	82	233	244
Expense, net	$631	$383	$322
$/BOE (1)	$1.79	$1.30	$1.04
Average effective interest rate	3.8%	3.9%	3.9%

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

Gross interest and other financing expense for 2017 increased from 2016 primarily due to the impact of higher average debt levels as a result of acquisitions completed in 2017. Capitalized interest of $82 million for 2017 was related to the Horizon Phase 3 expansion and the Kirby North project.
Net interest and other financing expense for 2017 increased 38% to $1.79 per BOE from $1.30 per BOE for 2016 (2015 – $1.04 per BOE). The increase for 2017 from 2016 was primarily due to higher average debt levels as a result of acquisitions completed in 2017 and lower capitalized interest related to the completion of Horizon Phase 2B and Phase 3.
The Company’s average effective interest rate of 3.8% for 2017 was consistent with 2016.

Principal Documents Exhibits

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)	2017	2016	2015
Crude oil and NGLs financial instruments	$(32)	$—	$(599)
Natural gas financial instruments	(7)	—	—
Foreign currency contracts	37	8	(244)
Realized (gain) loss	$(2)	$8	$(843)
Crude oil and NGLs financial instruments	$—	$—	$394
Natural gas financial instruments	(6)	6	—
Foreign currency contracts	43	19	(20)
Unrealized loss	$37	$25	$374
Net loss (gain)	$35	$33	$(469)

During 2017, net realized risk management gains were related to the settlement of crude oil price collars and natural gas AECO swaps, offset by the settlement of foreign currency contracts. The Company recorded a net unrealized loss of $37 million ($33 million after-tax) on its risk management activities for 2017 (2016 – $25 million unrealized loss, $21 million after-tax; 2015 – $374 million unrealized loss, $275 million after-tax).

Complete details related to outstanding derivative financial instruments at December 31, 2017 are disclosed in note 18 to the Company's consolidated financial statements.

FOREIGN EXCHANGE

($ millions)	2017	2016	2015
Net realized loss (gain)	$34	$38	$(97)
Net unrealized (gain) loss	(821)	(93)	858
Net (gain) loss [1]	$(787)	$(55)	$761

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

The net realized foreign exchange loss for 2017 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for 2017 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (2017 – unrealized loss of $280 million, 2016 – unrealized loss of $295 million, 2015 – unrealized gain of $649 million). The US/Canadian dollar exchange rate at December 31, 2017 was US$0.7988 (December 31, 2016 – US$0.7448, December 31, 2015 – US$0.7225).

Principal Documents Exhibits

INCOME TAXES

($ millions, except income tax rates)	2017	2016	2015
North America [1]	$(145)	$(377)	$86
North Sea	57	(74)	(117)
Offshore Africa	45	22	17
PRT – North Sea	(132)	(198)	(258)
Other taxes	11	9	11
Current income tax recovery	(164)	(618)	(261)
Deferred corporate income tax expense (recovery)	586	(106)	216
Deferred PRT expense (recovery) – North Sea	54	(135)	15
Deferred income tax expense (recovery)	640	(241)	231
	476	(859)	(30)
Income tax rate and other legislative changes [2]	(10)	221	(351)
	$466	$(638)	$(381)
Effective income tax rate on adjusted net earnings (loss) from operations [3]	27 %	45 %	61 %

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.

(2) During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $10 million. During 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. The UK government also enacted tax rate reductions relating to PRT, resulting in a decrease in the Company's net deferred income tax liability of $114 million. During 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015, increasing the Company's deferred corporate income tax liability by $579 million. In addition, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and PRT, and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company's net deferred income tax liability of $228 million.

(3) Excludes the impact of current and deferred PRT expense and other current income tax expense.

The effective income tax rate for 2017 and the comparable years included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income (loss) and tax rates in the countries in which the Company operates, in relation to net earnings (loss). In addition, the effective income tax rate for 2016 also reflected the successful resolution of certain prior year tax matters.

The current corporate income tax and PRT recoveries in the North Sea in 2017 and the comparable years included the impact of abandonment expenditures.

During 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $10 million.

During 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. In addition, the UK government also enacted legislation to reduce the PRT rate from 35% to 0% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes are still recoverable at a PRT rate of 50%. As a result of these tax changes, the Company's deferred PRT liability was reduced by $228 million and the deferred corporate income tax liability was increased by $114 million.

During 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred corporate income tax liability was increased by $579 million.

During 2015, the UK government enacted legislation that reduced the supplementary charge on oil and gas profits from 32% to 20% effective January 1, 2015. In addition, the legislation also reduced the PRT rate from 50% to 35% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to prior taxation years for PRT purposes were still recoverable at the previous tax rate of 50%. The legislation also replaced the existing Brownfield Allowance with a new Investment Allowance on qualifying capital expenditures, effective April 1, 2015. The new Investment Allowance is deductible for supplementary charge purposes, subject to certain restrictions. As a result of these tax changes, the Company's deferred corporate income tax liability was reduced by $217 million and the deferred PRT liability was reduced by $11 million.

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 reported results of operations, financial position or liquidity.

For 2018, the Company expects to recognize current income tax expense ranging from $300 million to $400 million in Canada and recoveries of $nil to $40 million in the North Sea and Offshore Africa.

During 2017, the Company filed Scientific Research and Experimental Development claims of approximately $345 million (2016 – $549 million; 2015 – $527 million) relating to qualifying research and development expenditures for Canadian income tax purposes.

NET CAPITAL EXPENDITURES [1]

($ millions)	2017	2016	2015
Exploration and Evaluation			
Net expenditures (proceeds) [2] [3] [4]	$149	$(6)	$(805)
Property, Plant and Equipment			
Net property acquisitions (dispositions) [2] [3] [4] [5]	1,219	159	(451)
Well drilling, completion and equipping	1,001	712	965
Production and related facilities	860	369	908
Capitalized interest and other [6]	91	91	102
Net expenditures	3,171	1,331	1,524
Total Exploration and Production	3,320	1,325	719
Horizon Oil Sands Mining and Upgrading			
Horizon Phases 2/3 construction costs	821	1,920	2,187
Sustaining capital	419	379	301
Turnaround costs	149	135	18
Capitalized interest and other [6]	76	284	224
Total Horizon Oil Sands Mining and Upgrading	1,465	2,718	2,730
Athabasca Oil Sands Project			
Acquisitions of Exploration and Evaluation assets [2] [4]	219	—	—
Net property acquisitions [2] [4]	11,604	—	—
Sustaining capital	142	—	—
Turnaround costs	6	—	—
Total Athabasca Oil Sands Project	11,971	—	—
Total Oil Sands Mining and Upgrading	13,436	2,718	2,730
Midstream [7]	80	(533)	8
Abandonments [8]	274	267	370
Head office	19	17	26
Total net capital expenditures	$17,129	$3,794	$3,853
By segment			
North America [2] [3] [4] [5]	$3,056	$1,048	$(119)
North Sea	160	126	230
Offshore Africa	104	151	608
Oil Sands Mining and Upgrading [4]	13,436	2,718	2,730
Midstream [7]	80	(533)	8
Abandonments [8]	274	267	370
Head office	19	17	26
Total	$17,129	$3,794	$3,853

(1) Net capital expenditures exclude adjustments related to fair value and revaluation adjustments, and include non-cash transfers of property, plant and equipment to inventory due to change in use.

(2) Includes Business Combinations.

(3) Includes proceeds from the Company’s disposition of properties.

(4) Total purchase consideration for the acquisition of interests in AOSP of $12,157 million includes $26 million of exploration and evaluation assets and $308 million of property, plant and equipment within the North America segment, and $219 million of exploration and evaluation assets and $11,604 million of property, plant and equipment within the Oil Sands Mining and Upgrading segment in 2017.

(5) Includes non-cash share consideration of $985 million received from PrairieSky on the disposition of royalty income assets in 2015 and the impact of other pre-tax gains on the sale of other properties totaling $49 million recognized in 2015.

(6)

Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.

(7) Includes non-cash share consideration of $190 million received from Inter Pipeline on the disposition of Midstream assets in 2016.

(8) 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 2017 were $17,129 million compared with $3,794 million for 2016 (2015 – $3,853 million). Net capital expenditures for 2017 included $12,157 million related to the acquisition of AOSP and other assets and $921 million related to the acquisition of assets in the Greater Pelican Lake region and other miscellaneous assets.

On November 7, 2017 the Company announced its 2018 Capital Budget. The budget reflects the Company's transition to a long life low decline asset base with a focus on reliability across the asset base and the continued integration and optimization of assets acquired in 2017. The 2018 budget is targeted at $4,335 million.

Drilling Activity

(number of wells)	2017	2016	2015
Net successful natural gas wells	21	9	19
Net successful crude oil wells [(1)]	495	174	115
Dry wells	7	7	6
Stratigraphic test / service wells	289	268	166
Total	812	458	306
Success rate (excluding stratigraphic test / service wells)	99%	96%	96%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 19% of the total net capital expenditures for 2017 compared with approximately 20% for 2016 (2015 – 1%).

During 2017, the Company targeted 22 net natural gas wells, including 7 wells in Northeast British Columbia, 14 wells in Northwest Alberta and 1 well in Northern Plains. The Company also targeted 499 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 415 primary heavy crude oil wells, 17 Pelican Lake heavy crude oil wells, 27 bitumen (thermal oil) wells and 2 light crude oil wells were drilled. Another 38 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for 2017 averaged approximately 120,100 bbl/d compared with approximately 111,000 bbl/d for 2016 (2015 – 129,800 bbl/d). Production volumes in 2017 reflected strong thermal oil production following the successful turnarounds at Primrose and Kirby South plants in 2017 and added production volumes as a result of the acquisition of other assets on May 31, 2017.

Operating performance at the Pelican Lake tertiary recovery project continued to be strong, leading to average production of approximately 51,700 bbl/d in 2017 compared with 47,600 bbl/d in 2016 (2015 – 50,800 bbl/d).

Horizon Oil Sands Mining and Upgrading

During the fourth quarter of 2017, Horizon Phase 3 expansion work was completed on schedule and within budget. Phase 3 activities included the expansion tie-in and commissioning of the production plant.

The Phase 2/3 expansion program is essentially complete with residual scope remaining related to Mature Fine Tailings ("MFT") and mine basal water.

North Sea

During 2017, the Company completed two injection wells (1.8 on a net basis) and two production wells (1.8 on a net basis) at Ninian. The Company also completed all of the heavy lifts at the Murchison platform, ceased production at the Ninian North field and commenced well plugging and abandonment activities. Abandonment activities are currently on schedule and within budget.

Offshore Africa

During 2017, the Company successfully completed the 18 day turnaround at Baobab ahead of schedule.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	2017	2016	2015
Working capital (1)	$513	$1,056	$1,193
Long-term debt (2) (3)	$22,458	$16,805	$16,794
Less: cash and cash equivalents	137	17	69
Long-term debt, net	$22,321	$16,788	$16,725
Share capital	$9,109	$4,671	$4,541
Retained earnings	22,612	21,526	22,765
Accumulated other comprehensive (loss) income	(68)	70	75
Shareholders' equity	$31,653	$26,267	$27,381
Debt to book capitalization (3) (4)	41%	39%	38%
Debt to market capitalization (3) (5)	29%	26%	34%
After-tax return on average common shareholders' equity (6)	8%	(1%)	(2%)
After-tax return on average capital employed (3) (7)	6%	0%	(1%)

(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 (2017 - $1,877 million, 2016 - $1,812 million, 2015 - $1,729 million).

(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and premiums and transaction costs.

(4) Calculated as net current and long-term debt; divided by the book value of common shareholders' equity plus net current and long-term debt.

(5) Calculated as net current and long-term debt; divided by the market value of common shareholders' equity plus net current and long-term debt.

(6) Calculated as net earnings (loss) for the year; as a percentage of average common shareholders' equity for the year.

(7) Calculated as net earnings (loss) plus after-tax interest and other financing expense for the year; as a percentage of average capital employed for the year.

At December 31, 2017, the Company's capital resources consisted primarily of funds flow from operations, available bank credit facilities and access to debt capital markets. Funds 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 reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated funds flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and 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.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

Monitoring funds flow from operations, which is the primary source of funds;

Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;

Utilizing funds flow from operations to facilitate debt reduction. Subsequent to December 31, 2017, the Company:

extended the fully drawn $750 million non-revolving credit facility originally due February 2019 to February 2021 and fully repaid and cancelled the $125 million non-revolving credit facility;

repaid and cancelled $150 million of the $3,000 million non-revolving term loan facility; and

repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

Reviewing the Company's borrowing capacity:

During 2017, the Company extended $2,095 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The remaining $330 million outstanding under this facility continues under the previous terms and matures in June 2019. The other $2,425 million revolving credit facility matures in June 2020. The revolving credit facilities are extendible annually 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 2017, the $1,500 million non-revolving term credit facility was increased to $2,200 million and the maturity date was extended to October 2019 from April 2018. Borrowings under the $2,200 million non-revolving credit facility 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. As at December 31, 2017, the $2,200 million facility was fully drawn.

Borrowings under the $750 million non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.

In addition to the credit facilities described above, during 2017 the Company entered into a $3,000 million non-revolving term loan facility to finance the acquisition of AOSP and other assets. This facility matures in May 2020 and is subject to annual amortization of 5% of the original balance. Borrowings under the term loan facility 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. The facility also supports a US$375 million letter of credit relating to the deferred purchase consideration payable to Marathon in March 2018. As at December 31, 2017, the $3,000 million facility was fully drawn.

The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

During 2017, the Company issued $900 million of 2.05% medium-term notes due June 2020, $600 million of 3.42% medium-term notes due December 2026 and $300 million of 4.85% medium-term notes due May 2047. Proceeds from the securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

During 2016, the Company issued $1,000 million of 3.31% medium-term notes due February 2022.

During 2017, the Company repaid US$1,100 million of 5.70% notes, and issued US$1,000 million of 2.95% notes due January 2023, US$1,250 million of 3.85% notes due June 2027 and US$750 million of 4.95% notes due June 2047. Proceeds from the debt securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

During 2016, the Company repaid US$250 million of 6.00% notes and US$500 million of three-month LIBOR plus 0.375% notes.

Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and

Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default.

At December 31, 2017, the Company had in place bank credit facilities of $11,050 million, of which approximately $4,112 million was available, resulting in liquidity of $4,249 million, including cash and cash equivalents. This excludes certain other dedicated credit facilities supporting letters of credit.

At December 31, 2017, the Company had total US dollar denominated debt with a carrying amount of $13,753 million (US$10,989 million), before transaction costs and original issue discounts. This included $4,239 million (US$3,389 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$2,339 million). The fixed repayment amount of these hedging instruments is $4,150 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $89 million to $13,664 million as at December 31, 2017.

Net long-term debt was $22,321 million at December 31, 2017, resulting in a debt to book capitalization ratio of 41% (December 31, 2016 – 39%, December 31, 2015 - 38%); 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 funds 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. Further details related to the Company's long-term debt at December 31, 2017 are discussed in note 10 to the Company's consolidated financial statements.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support 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. At February 28, 2018 the Company had no commodity derivative financial instruments outstanding.

Share Capital

As at December 31, 2017, there were 1,222,769,000 common shares outstanding (December 31, 2016 – 1,110,952,000 common shares) and 56,036,000 stock options outstanding. As at February 27, 2018, the Company had 1,225,805,000 common shares outstanding and 54,701,000 stock options outstanding.

On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share, beginning with the dividend payable on April 1, 2018. On March 1, 2017, the Board of Directors approved an increase in the quarterly dividend to $0.275 per common share, beginning with the dividend payable on April 1, 2017. On November 2, 2016, the Board of Directors approved an increase in the quarterly dividend to $0.25 per common share (previous quarterly dividend rate of $0.23 per common share), beginning with the dividend payable on January 1, 2017. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

During 2016, the Company completed the net distribution of approximately 21.8 million PrairieSky common shares to the shareholders of record of the Company as at June 3, 2016, completing the previously announced Plan of Arrangement. The distribution was recognized as a return of capital of $546 million. Subsequent to the distribution, the Company's ownership interest in PrairieSky was less than 10% of the issued and outstanding common shares of

PrairieSky.

On May 16, 2017, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 27,931,135 common shares, over a 12 month period commencing May 23, 2017 and ending May 22, 2018. During 2017, 2016 and 2015, the Company did not purchase any common shares for cancellation.

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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. In connection with the acquisition of AOSP and other assets, the Company also assumed certain pipeline and other commitments. The following table summarizes the Company's commitments as at December 31, 2017:

($ millions)	2018	2019	2020	2021	2022	Thereafter
Product transportation and pipeline	$680	$584	$526	$482	$422	$ 3,868
Offshore equipment operating leases	$181	$92	$70	$68	$8	$ —
Long-term debt (1)	$2,027	$4,228	$4,231	$760	$1,000	$ 10,351
Interest and other financing expense (2)	$842	$755	$638	$561	$513	$ 5,384
Office leases	$43	$42	$42	$39	$30	$ 118
Other (3)	$87	$41	$40	$39	$43	$ 333

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

(2) Interest and other financing payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2017.

(3) In addition to the amounts disclosed above, beginning on the earlier of the commercial operations date of the Redwater refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of its various development projects. 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 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, 2017, 2016 and 2015, 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 report on 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, 2017, prepared in accordance with NI 51-101 reserves disclosures:

Proved Reserves	Light and Medium Crude Oil	Primary Heavy Crude Oil	Pelican Lake Heavy Crude Oil	Bitumen (Thermal Oil)	Synthetic Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent
	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(Bcf)	(MMbbl)	(MMBOE)
December 31, 2016	389	187	264	1,269	2,559	6,617	198	5,969
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	14	—	20	—	276	15	99

Infill Drilling	4	7	—	—	—	191	17	60
Improved Recovery	—	1	1	—	—	1	—	2
Acquisitions	6	20	76	23	2,321	116	1	2,467
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	4	—	—	—	—	(30)	—	(1)
Technical Revisions	1	4	5	82	487	207	13	626
Production	(34)	(35)	(19)	(44)	(103)	(607)	(15)	(351)
December 31, 2017	374	198	327	1,350	5,264	6,771	229	8,871

Proved Plus Probable Reserves	Light and Medium Crude Oil	Primary Heavy Crude Oil	Pelican Lake Heavy Crude Oil	Bitumen (Thermal Oil)	Synthetic Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent
	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(Bcf)	(MMbbl)	(MMBOE)
December 31, 2016	619	259	384	2,517	3,604	9,076	284	9,179
Discoveries	—	—	—	—	—	—	—	—
Extensions	8	22	—	39	—	554	25	187
Infill Drilling	7	10	—	—	—	295	26	92
Improved Recovery	—	1	2	—	—	1	—	3
Acquisitions	8	26	99	50	2,496	145	1	2,704
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	1	—	—	—	—	(29)	—	(3)
Technical Revisions	(65)	(11)	3	18	66	185	14	55
Production	(34)	(35)	(19)	(44)	(103)	(607)	(15)	(351)
December 31, 2017	544	272	469	2,580	6,063	9,619	335	11,866

At December 31, 2017, the company gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 7,742 MMbbl, and company gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 10,263 MMbbl. Proved reserves additions and revisions replaced 1,250% of 2017 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 2,530 MMbbl, and additions to proved plus probable reserves amounted to 2,820 MMbbl. Net positive revisions amounted to 596 MMbbl for proved reserves and 26 MMbbl for proved plus probable reserves, primarily due to technical revisions.

At December 31, 2017, the company gross proved natural gas reserves totaled 6,771 Bcf, and company gross proved plus probable natural gas reserves totaled 9,619 Bcf. Proved reserves additions and revisions replaced 125% of 2017 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 584 Bcf, and additions to proved plus probable reserves amounted to 994 Bcf. Net positive revisions amounted to 177 Bcf for proved reserves and 156 Bcf for proved plus probable reserves, primarily due to technical revisions.

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, extracting 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 reserves revisions due to economic and technical factors. Reserves revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;

Reservoir quality and uncertainty of reserves 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 and in mining, extracting and upgrading the Company's bitumen products;

Timing and success of integrating the business and operations of acquired companies and assets;

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 ability to secure adequate transportation for products which could be affected by pipeline constraints, the construction by third parties of new or expansion of existing pipeline capacity and other factors;

The access to markets for the Company's products;

The risk of significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach that could adversely affect the Company's operations; 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 monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default. Derivative financial instruments are periodically 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 counterparties that are substantially all investment grade financial institutions. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions. The Company has implemented cyber security protocols and procedures to reduce the risk of failure or a significant breach of the Company's information technology systems and related data and control systems.

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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, 2017.

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. 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. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings.

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 to preserve high value diversity. 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 for air, water and biodiversity, industry operating standards and guidelines, and internal corporate standards. Training and due diligence for operators and contractors is key to the effectiveness of the Company's environmental management programs and the prevention of incidents to protect the environment. 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 through biodiversity protection and restoration 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 carbon capture at hydrotreaters, the injection of CO_2 into tailings and for use in EOR, and the Quest carbon capture and storage facility as part of AOSP;
- A program in place related to progressive reclamation and tailings management in Oil Sands Mining and Upgrading including low fines mining;
- Participation and support for the Joint Oil Sands Monitoring Program; and
- Wildlife monitoring and mitigation plans to help maintain biodiversity, as well as mitigation and restoration programs targeted specifically at boreal caribou.

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 4.7% (2016 – 5.2%; 2015 – 5.9%). For 2017, the Company's capital expenditures included $274 million for abandonment expenditures (2016 – $267 million; 2015 – $370 million). The Company's estimated discounted ARO at December 31, 2017 was as follows:

($ millions)	2017	2016
Exploration and Production		
North America	$1,840	$1,444
North Sea	755	837
Offshore Africa	245	244
Oil Sands Mining and Upgrading	1,486	717
Midstream	1	1
	$4,327	$3,243

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine sites, 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. The Company's integrated GHG emissions reduction strategy includes: 1) integrating emission reduction in project planning and operations; 2) leveraging technology to create value and enhance performance; 3) investing in research and development and supporting collaboration; 4) focusing on continuous improvement to drive long-term emissions reduction; 5) leading in carbon capture and sequestration/storage; 6) engaging proactively in policy and regulatory development (including trading capacity and offsetting emissions); and, 7) considering and developing new business opportunities and trends.

In Canada, the federal government has ratified the Paris climate change agreement, with a commitment to reduce GHG emissions by 30% from 2005 levels by 2030. Canada has also committed to reduce methane emissions from the upstream oil and gas sector by 40-45% by 2025, as compared to 2012 levels. The federal government is also developing a comprehensive management system for air pollutants and has released regulations pertaining to certain boilers, heaters and compressor engines operated by the Company. The federal government is also developing a Clean Fuel Standard which may affect production and consumption of fuels in Canada. Effective January 1, 2017, the Alberta government implemented increases in both the carbon price and stringency of the existing large-emitter regulatory system. The Alberta government has introduced additional changes to this system beginning in 2018, as well as a program to reduce methane emissions from the upstream oil and gas sector, and a carbon price on combustion emissions from the upstream oil and gas sector beginning in 2023. In British Columbia, the provincial government has announced a methane reduction target, comparable to the federal target.

In Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. The carbon price in Alberta is currently $30/tonne for emissions above the regulated limits. Seven of the Company's operated facilities (the Horizon and Athabasca oil sands facilities, the Primrose/Wolf Lake in situ heavy crude oil facilities, the Kirby South in situ heavy crude oil facility, the Peace River in situ heavy crude oil facility, the Hays sour natural gas plant, and the Wapiti gas plant) are subject to compliance under the regulation. The non-operated Scotford Upgrader is also subject to compliance under the regulations. The non-operated North West Redwater bitumen upgrader and refinery will not be subject to a reduction target until 2019. In British Columbia, carbon tax is currently being assessed at $30/tonne of CO_2e on fuel consumed and gas flared in the province, with the rate increasing to $35/tonne on April 1, 2018. The British Columbia Government will be increasing the carbon tax at a rate of $5 per tonne of CO_2e annually to

$50 per tonne of CO_2e on April 1, 2021. The Saskatchewan government has released a Climate Change Strategy that will regulate facilities emitting more than 25 kilotonnes of CO_2e annually and will likely require the North Tangleflags in situ heavy oil facility and the Senlac in situ heavy oil facility to meet reduction targets for GHG emissions once the governing legislation comes into force. The Saskatchewan strategy also includes measures that will regulate GHG emissions (including methane) at facilities below the 25 kilotonne/year threshold. 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.

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 may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in this MD&A and the audited consolidated financial statements for the year ended December 31, 2017.

A) 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 related Cash Generating Units ("CGUs"), aggregated at a 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 future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and production costs, discount rates and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

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 discounted at rates currently ranging from 10% to 12% 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 an indication of impairment exists, the Company performs an impairment test related to the specific assets at the CGU level.

B) Crude Oil and Natural Gas Reserves

Reserves estimates are based on engineering data, estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations and judgements. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information. Reserves 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 reserves estimates would result in a higher or lower depletion, depreciation and amortization charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of E&E and property, plant and equipment carrying amounts.

C) 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 may 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 4.7%. 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.

D) 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 amount 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 a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

E) Risk Management Activities

The Company periodically 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.

F) Purchase Price Allocations

Purchase prices related to business combinations 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 acquired assets and liabilities. The most significant assumptions and judgements relate to the estimation of the fair value of crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates crude oil and natural gas reserves. Reserves 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.

G) 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 changes in the fair value of the liability.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In October 2017, the IASB issued amendments to IAS 28 "Investments in Associates and Joint Ventures" to clarify that the impairment provisions in IFRS 9 apply to financial instruments in an associate or joint venture that are not accounted for using the equity method, including long-term interests that form part of the net investment in the associate or joint venture. The amendments are effective January 1, 2019 with earlier adoption permitted. The amendments are required to be adopted retrospectively. The Company is assessing the impact of the amendments on its consolidated financial statements.

In June 2017, the IASB issued IFRIC 23 "Uncertainty over Income Tax Treatments". The interpretation provides guidance on how to reflect the effects of uncertainty in accounting for income taxes where IAS 12 is unclear. The interpretation is effective January 1, 2019. The Company is assessing the impact of this interpretation on its consolidated financial statements.

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaces IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees. The new standard is effective January 1, 2019 with earlier adoption permitted providing that IFRS 15 has been adopted. The new standard is required to be applied retrospectively, with a policy alternative of restating comparative prior periods or recognizing the cumulative adjustment in opening retained earnings at the date of adoption. The Company is assessing the impact of this standard on its consolidated financial statements.

IFRS 15 "Revenue from Contracts with Customers"

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to provide guidance on the recognition of revenue and cash flows arising from an entity's contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements. In 2015, the IASB deferred the effective date for the new standard to January 1, 2018. The new standard is required to be adopted retrospectively, with earlier adoption permitted.

Effective January 1, 2018, the Company retrospectively adopted IFRS 15. Adoption of the new standard did not have a significant impact on the Company's recognition and measurement of revenue; however, it will require certain additional disclosures.

Upon adoption of IFRS 15, the Company applied the practical expedient such that contracts that were completed in the comparative periods have not been restated.

IFRS 9 "Financial Instruments"

Effective January 1, 2014, the Company adopted the version of IFRS 9 “Financial Instruments” issued November 2013. In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model. The amendments are effective January 1, 2018 and are required to be adopted retrospectively.

Effective January 1, 2018, the Company adopted the amendment to IFRS 9 and elected to apply the limited exemption in IFRS 9 relating to transition for impairment. Adoption of the amendment did not have a significant impact on the Company’s previous accounting for impairment of financial assets.

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, 2017, 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, 2017, 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 2017 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.

Capital expenditures in 2018 are currently targeted to be as follows:

($ millions)	2018
Exploration and Production	
North America natural gas and NGLs	$440
North America crude oil	1,115
International crude oil	410
Thermal In Situ Oil Sands	960
Net acquisitions, midstream and other	30
Total Exploration and Production	$2,955
Oil Sands Mining and Upgrading	
Environment, technology and project development	500
Sustaining capital	660
Turnarounds, reclamation and other	220
Total Oil Sands Mining and Upgrading	$1,380
Total	$4,335

Principal Documents Exhibits

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of funds flow from operations and net earnings (loss) due to changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2017, 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.

	Funds flow from operations ($ millions)	Funds flow from operations (per common share, basic)	Net earnings (loss) ($ millions)	Net earnings (loss) (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl	$ 248	$ 0.21	$ 227	$ 0.19
Natural gas – AECO C$0.10/Mcf1)	$ 33	$ 0.03	$ 33	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 127	$ 0.11	$ 98	$ 0.08
Natural gas – 10 MMcf/d	$ 1	$ —	$ —	$ —
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 133 - 137	$ 0.12	$ 17	$ 0.01
Interest rate change – 1%	$ 47	$ 0.04	$ 47	$ 0.04

(1) For details of financial instruments in place, refer to note 18 to the Company’s consolidated financial statements as at December 31, 2017.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2017	2016	2015
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	359,964	332,802	361,216	383,537	359,449	350,958	399,982
North America – Oil Sands Mining and Upgrading	192,491	257,541	354,365	321,496	282,026	123,265	122,911
North Sea	23,042	26,304	24,832	19,548	23,426	23,554	22,216
Offshore Africa	22,616	20,480	18,776	19,519	20,335	26,096	19,079
Total	598,113	637,127	759,189	744,100	685,236	523,873	564,188
Natural gas (MMcf/d)							
North America	1,613	1,603	1,593	1,596	1,601	1,622	1,663
North Sea	37	37	46	37	39	38	36
Offshore Africa	23	16	25	23	22	31	27
Total	1,673	1,656	1,664	1,656	1,662	1,691	1,726
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	628,671	599,901	626,642	649,473	626,230	621,239	677,270
North America – Oil Sands Mining and Upgrading	192,491	257,541	354,365	321,496	282,026	123,265	122,911
North Sea	29,238	32,517	32,487	25,723	29,989	29,913	28,191
Offshore Africa	26,507	23,212	23,005	23,402	24,019	31,365	23,529
Total	876,907	913,171	1,036,499	1,020,094	962,264	805,782	851,901

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PER UNIT RESULTS – EXPLORATION AND PRODUCTION

	Q1	Q2	Q3	Q4	2017	2016	2015
Crude oil and NGLs ($/bbl) (1)							
Sales price (2)	$47.05	$47.12	$46.33	$53.42	$48.57	$36.93	$41.13
Transportation	2.54	3.06	2.81	2.82	2.80	2.61	2.60
Realized sales price, net of transportation	44.51	44.06	43.52	50.60	45.77	34.32	38.53
Royalties	4.89	4.83	5.33	5.84	5.24	3.40	4.30
Production expense	14.37	15.51	14.71	15.03	14.89	14.10	15.74
Netback	$25.25	$23.72	$23.48	$29.73	$25.64	$16.82	$18.49
Natural gas ($/Mcf) (1)							
Sales price (2)	$3.25	$2.97	$2.29	$2.55	$2.76	$2.32	$3.16
Transportation	0.43	0.34	0.33	0.46	0.39	0.33	0.38
Realized sales price, net of transportation	2.82	2.63	1.96	2.09	2.37	1.99	2.78
Royalties	0.19	0.12	0.07	0.08	0.11	0.09	0.10
Production expense	1.28	1.25	1.22	1.33	1.27	1.18	1.34
Netback	$1.35	$1.26	$0.67	$0.68	$0.99	$0.72	$1.34
Barrels of oil equivalent ($/BOE) (1)							
Sales price (2)	$35.98	$33.94	$33.27	$38.78	$35.54	$27.58	$32.60
Transportation	2.57	2.67	2.51	2.86	2.66	2.44	2.56
Realized sales price, net of transportation	33.41	31.27	30.76	35.92	32.88	25.14	30.04
Royalties	3.38	3.09	3.36	3.75	3.40	2.21	2.85
Production expense	11.67	12.11	11.73	12.28	11.95	11.18	12.70
Netback	$18.36	$16.07	$15.67	$19.89	$17.53	$11.75	$14.49

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

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING

	Q1	Q2	Q3	Q4	2017	2016	2015
Crude oil and NGLs ($/bbl)							
SCO sales price (1)	$67.85	$63.39	$56.55	$70.85	$63.98	$58.59	$61.39
Bitumen royalties (2)	1.14	1.38	1.39	2.45	1.64	0.54	1.08
Transportation	1.17	1.32	1.61	1.88	1.54	1.77	1.81
Adjusted cash production costs (3)	22.08	23.44	22.69	24.99	23.40	25.20	28.61
Netback	$43.46	$37.25	$30.86	$41.53	$37.40	$31.08	$29.89

(1) The realized sales price for 2017 reflects the weighted average price of Horizon SCO and AOSP SCO while the realized sales price for 2016 and 2015 reflects the Horizon SCO price only. The Horizon realized sales price reflects a premium light sweet SCO compared to the blend at AOSP.
(2) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.
(3) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

Principal Documents Exhibits

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2017	2016
TSX – C$						
Trading volume (thousands)	176,219	142,680	144,852	124,671	588,422	653,727
Share Price ($/share)						
High	$ 44.84	$ 45.94	$ 42.88	$ 47.00	$ 47.00	$ 46.74
Low	$ 37.34	$ 36.44	$ 35.90	$ 40.62	$ 35.90	$ 21.27
Close	$ 43.54	$ 37.42	$ 41.79	$ 44.92	$ 44.92	$ 42.79
Market capitalization as at December 31 ($ millions)					$ 54,927	$ 47,538
Shares outstanding (thousands)					1,222,769	1,110,952
NYSE – US$						
Trading volume (thousands)	205,031	153,928	130,936	118,113	608,008	892,220
Share Price ($/share)						
High	$ 33.39	$ 34.31	$ 34.48	$ 36.78	$ 36.78	$ 35.28
Low	$ 28.39	$ 27.53	$ 27.88	$ 32.11	$ 27.53	$ 14.60
Close	$ 32.79	$ 28.84	$ 33.49	$ 35.72	$ 35.72	$ 31.88
Market capitalization as at December 31 ($ millions)					$ 43,677	$ 35,417
Shares outstanding (thousands)					1,222,769	1,110,952

Principal Documents Exhibits

ADDITIONAL DISCLOSURE

Certifications

The required disclosure is included in Exhibits 31.1, 31.2, 32.1 and 32.2 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, 2017, 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, 2017, 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 "Report of Independent Registered Public Accounting Firm" that accompanies Canadian Natural's audited consolidated financial statements for the fiscal year ended December 31, 2017, 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, 2017, 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, Governance and Risk Committee of the Board of Directors reviews the Code of Ethics annually 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: Paul M. Mendes, Vice President, Legal, General Counsel and Corporate Secretary, Canadian Natural Resources Limited, 2100-855 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 1973. 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, 2017 and December 31, 2016, 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 $2,960,000 for 2017 and were $2,512,000 for 2016.

Audit-Related Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ended December 31, 2017 and December 31, 2016, for audit-related services by PwC including pension assets, Crown Royalty Statements and in respect of the AOSP acquisition, were $574,000 for 2017 and were $246,000 for 2016. 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, 2017 and December 31, 2016, for professional services rendered by PwC for tax services related to expatriate personal tax compliance and other corporate tax return matters were $470,000 for 2017 and were $410,000 for 2016. 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, 2017 and December 31, 2016 for other services were $52,000 for 2017 and were $62,000 for 2016, 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 2017.

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, 2017:

($ millions)	2018	2019	2020	2021	2022	Thereafter
Product transportation and pipeline	$680	$584	$526	$482	$422	$ 3,868
Offshore equipment operating leases	$181	$92	$70	$68	$8	$ —
Long-term debt [1]	$2,027	$4,228	$4,231	$760	$1,000	$ 10,351
Interest and other financing expense [2]	$842	$755	$638	$561	$513	$ 5,384
Office leases	$43	$42	$42	$39	$30	$ 118
Other [3]	$87	$41	$40	$39	$43	$ 333

(1) Long-term debt represents principal repayments only and does not reflect original issue discounts and premiums 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, 2017.

(3) In addition to the amounts disclosed above, beginning on the earlier of the commercial operations date of the North West Redwater refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

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 current 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.

Principal Documents Exhibits

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.

Principal Documents Exhibits

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 21st day of March, 2018.

CANADIAN NATURAL
RESOURCES LIMITED

By: SIGNED "TIM S. McKAY"
Name: Tim S. McKay
Title: President

Principal Documents Exhibits

Documents filed as part of this report:
EXHIBIT INDEX

Exhibit No.	Description
23.1	Consent of Independent Registered Public Accounting Firm.
23.2	Consent of Sproule Associates Limited, Independent Petroleum Engineering Consultants.
23.3	Consent of Sproule International Limited, Independent Petroleum Engineering Consultants.
23.4	Consent of GLJ Petroleum Consultants Ltd., Independent Petroleum Engineering Consultants.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
32.1	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).
32.2	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).
99.1	Supplementary Oil & Gas Information for the fiscal year ended December 31, 2017.
101	Interactive data files with respect to the consolidated financial statements for the fiscal years ended December 31, 2017 and 2016.