CANADIAN NATURAL RESOURCES LTD
Form 40-F
March 27, 2019

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, 2018	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, 28 Liberty Street, New York, New York 10005
(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.
1,201,885,667 Common Shares outstanding as of December 31, 2018

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 6, 2019 the reported Bank of Canada noon rate for one Canadian dollar was US$0.7438. On March 6, 2019 the reported Bank of Canada noon rate for one U.S. dollar was C$1.3444.

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, 2018.

B. Audited Annual Financial Statements

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2018 and 2017, 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, 2018.

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, 2018, see Exhibit 99.1 to this Annual Report on Form 40-F.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2018

March 27, 2019

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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
C$ or $	Canadian dollars
“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	includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, synthetic crude oil and bitumen (thermal oil)
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	discounted value of crude oil and natural gas reserves plus value of unproved land, less net debt
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

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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, production expenses, 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 Horizon, AOSP and Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the cost and timing 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, NGLs or SCO that the Company may be reliant upon to transport its products to market, development and deployment of technology and technological innovations, the assumption of operations at processing facilities, and the "2019 Activity" section of this AIF with respect to budgeted capital expenditures for 2019, also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are 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 actual 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, natural gas and NGL 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; the 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; the 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; the 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 expenditures and production expenses); 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 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 applicable 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 the Company'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 " company gross" basis unless otherwise stated and realized prices are net of blending and feedstock costs and exclude the effects of risk management activities. 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:1bbl conversion 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, 2018, 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, 2018, 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, 2018 and a preparation date of February 4, 2019. 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 Oil Sands Mining and Upgrading 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 98 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; adjusted funds flow (previously referred to as funds flow from operations); net capital expenditures; 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), cash flows from operating activities, and cash flows used in investing activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measure adjusted net earnings (loss) from operations is reconciled to net earnings (loss), as determined in accordance with IFRS in the "Financial and Operational Highlights" section of the MD&A for the year ended December 31, 2018. Additionally, the non-GAAP measure adjusted funds flow is reconciled to cash flows from operating activities, as determined in accordance with IFRS, in the "Financial and Operational Highlights" section of the MD&A. The non-GAAP measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the "Net Capital Expenditures" section of the MD&A. The derivation of adjusted cash production costs is included in the “Operating Highlights – Oil Sands Mining and Upgrading” section of the MD&A. The non-GAAP measure free cash flow represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital from operating activities, abandonment, certain movements in other long-term assets, less net capital expenditures and dividends paid on common shares of the Company.

Principal Documents Exhibits

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
January 1, 2003 - Rio Alto Exploration Ltd.
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.
January 1, 2019 - Laricina Energy Ltd.

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
Sukunka Natural Resources Inc.	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.

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

2016

In June 2016, the Company completed the net distribution of approximately 21.8 million PrairieSky Royalty Ltd. ("PrairieSky") common shares to the shareholders of record of the Company as at June 3, 2016, completing a previously announced Plan of Arrangement. As part of an earlier transaction, 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. 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

On May 31, 2017, the Company completed its acquisition of a direct and indirect 70% interest in AOSP, including 70% of the Scotford Upgrader and the Quest Carbon Capture and Storage ("CCS") project, as well as additional working interests in other producing and non-producing oil sands leases through a transaction with Shell Canada Limited and certain of its subsidiaries ("Shell") and Marathon Oil Corporation ("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 as determined at the closing date, and deferred purchase consideration of $506 million (US$375 million). To finance the acquisition of the AOSP, the Company entered into a $3,000 million non-revolving term credit facility maturing May 2020. 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.

In addition, in 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.

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.

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.

2018

In March 2018, the Company paid the deferred purchase consideration of US$375 million to Marathon Oil in connection with the AOSP acquisition.

In the second quarter of 2018, the Company extended its $2,425 million revolving syndicated credit facility originally maturing in June 2020 to June 2022 and extended its $2,200 million non-revolving facility from October 2019 to October 2020. In 2018, the Company also 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 $1,200 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 September, 2018, the Company completed the acquisition of all of the issued and outstanding common shares and senior notes of Laricina Energy Ltd. ("Laricina") for a total purchase price of $95 million. Laricina was amalgamated with the Company on January 1, 2019.

In September 2018, the Company also completed its acquisition of a 100% working interest in the Joslyn oil sands project for a total purchase consideration of $100 million cash on closing and annual cash payments of $25 million over each of the subsequent five years.

In 2018, the Gabonese Republic approved cessation of production from the Company's Olowi field and the terms of termination of the Olowi Production Sharing Contract and the surrender of the permit area back to the Gabonese Republic.

In November 2018, the Company announced certain senior management promotions positioning it for continued growth in both the long life low decline assets and low capital exposure assets.

2019

The government of Alberta announced a mandatory curtailment of crude oil and bitumen production on December 2, 2018, which took effect on January 1, 2019. The amount of the curtailment is subject to monthly adjustment by the government.

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 and cash flow 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, 2018, the Company had the following full time equivalent permanent employees:

North America, Exploration and Production	4,395
North America, Oil Sands Mining and Upgrading	4,948
North Sea and Offshore Africa	366
Total Company	9,709

Operational discipline, together with safe, effective and efficient operations and cost control, are fundamental to the Company. By consistently managing costs throughout all industry cycles, the Company believes it will achieve continued growth. Safe operations that are effective and efficient 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 entering new core regions or increasing the Company's presence in existing core regions.

The Company's business approach is to maintain large project inventories and production diversification among each of its products: SCO, natural gas, light and medium crude oil and NGLs, bitumen (thermal oil), primary heavy crude oil and Pelican Lake heavy crude 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. SCO from the oil sands mining and upgrading operations in Northern Alberta accounted for 39% of 2018 production. Natural gas, primarily produced in Alberta, British Columbia and Saskatchewan, accounted for 24% of 2018 production. Light and medium crude oil and NGLs represented 13% of 2018 production, and were produced from Alberta, British Columbia, Saskatchewan and Manitoba, as well as from the Company's North Sea and Offshore Africa operations. Also produced from Alberta and Saskatchewan were bitumen (thermal oil), which accounted for 10% of 2018 production, primary heavy crude oil which accounted for 8% of 2018 production, and and Pelican Lake heavy crude oil, which accounted for 6% of 2018 production. The Company's 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. Midstream assets also include a 50% interest in the North West Redwater Partnership.

In addition, the Company has entered into a 20 year transportation agreement to ship 75,000 bbl/d of crude oil on the proposed Trans Mountain Pipeline Expansion. The National Energy Board has provided its recommendation that construction of the pipeline should proceed and related consultations by the federal government with Indigenous communities are ongoing. Subject to federal cabinet approval, the project could be issued a revised Certificate of Public Convenience and Necessity this summer with construction re-starting as early as August 2019. The Company has also entered into a 20 year transportation agreement to ship 175,000 bbl/d of crude oil on the proposed TransCanada Keystone XL Pipeline. The proponent is awaiting the completion of a new supplemental environmental review addressing issues raised through litigation in a Montana Federal Court case. A decision is also expected in April 2019 on the Nebraska Public Service Commission's route approval. Pre-construction activities have started and the proponent is working to maintain a 2021 in-service date.

A. ENVIRONMENTAL MATTERS

The Company carries 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 government regulatory authorities 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, water management and land management to minimize disturbance impacts. 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 (the "Plan") along with the Company's 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 is key to the effectiveness of the Company's environmental management programs and the prevention of incidents to protect the environment. The Company, as a part of its Plan, has implemented programs that include: environmental planning to assess impacts and implement avoidance and mitigation programs in order to preserve high value biodiversity; continued evaluation of new technologies to reduce environmental impacts including support for Canada's Oil Sands Innovation Alliance ("COSIA"), the Petroleum Technology Alliance Canada and other research institutions; CO_2 reduction programs including carbon capture, CO_2 injection for EOR, CO_2 sequestration in tailings and the Quest carbon capture and storage facility; a methane emission reduction program, including solution gas conservation to reduce methane venting and an equipment retrofit program to reduce methane emissions from pneumatic equipment; optimization of efficiencies at the Company's facilities; water programs to improve efficiency of use and recycle rates as well as reduce fresh water use; and an effective reclamation and decommissioning program across the Company's operations, returning sites to their former state. In North America, the Company has implemented: programs for well abandonment and progressive reclamation of large contiguous areas of land, which advances biodiversity and establishes functional wildlife habitats; tailings management in Oil Sands Mining to minimize fine tailings and promote reclamation; monitoring programs to assess changes to biodiversity, wildlife and fisheries in order to manage construction and operation effects and to assess reclamation success; participation and support for the Oil Sands Monitoring Program of regionally important resources; groundwater monitoring for all thermal in situ and mine operations; an active spill prevention and management program; and an internal environmental compliance audit and inspection program of operating facilities.

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 2018, Canadian Natural continued its environmental liability reduction program with the abandonment of 1,293 inactive wells. In addition, reclamation was initiated at many of these sites with the eventual goal of reclamation certification. In 2018, the Company received 717 reclamation certificates representing 1,383 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 provincially 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.

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 in policy and regulatory development (including trading capacity and offsetting emissions); and considering and developing new business opportunities and trends.

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 continues to enhance its 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.

The Company also continues to implement flaring, venting, fuel and solution gas conservation programs, which influence and direct its future plans for new projects and facilities. In 2018, the Company completed approximately 425 gas conservation projects in its primary heavy crude oil operations, resulting in a reduction of approximately 2.4 million tonnes/year of CO_2e. Over the past five years, the Company has spent over $72 million in its primary heavy crude oil and in situ oil sands operations to conserve the equivalent of over 16.8 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 and has ongoing methane reduction programs for pneumatic devices. Oil Sands Mining 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 that enables 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 through 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 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 federal or respective provincial governments, which give the holder the right to explore for and produce bitumen, 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. 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 (i) a comprehensive management system for air pollutants and has released regulations pertaining to certain boilers, heaters and compressor engines operated by the Company; and (ii) a Clean Fuel Standard, which may affect production and consumption of fuels in Canada.

Effective January 1, 2018, the Alberta government implemented the Carbon Competitiveness Incentive Regulation (CCIR) to replace the Specified Gas Emitters Regulation, for the regulation of GHG emissions from large facilities. The Alberta government has also finalized regulations to reduce methane emissions from the upstream oil and gas sector (consistent with the federal reduction target), with the first regulatory requirements coming into effect January 1, 2020. A previously announced carbon price on combustion emissions from the upstream oil and gas sector is scheduled to begin in 2023. In British Columbia, the provincial government has announced a methane reduction target, comparable to the federal target, and has released final regulations to achieve this target. The Saskatchewan government has also released a regulation to reduce methane emissions from crude oil production facilities, effective 2020. In Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually, or for those facilities that elect to "opt-in" to the regulations. The carbon price in Alberta is currently $30/tonne for emissions above the regulated limits. Eight of the Company's operated facilities (the Horizon and AOSP 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, the Wapiti gas plant and the Brintnell power generation facility) 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 2020. In British Columbia, carbon tax is currently being assessed at $35/tonne of CO_2e on fuel consumed and gas flared in the province, with the rate increasing to $40/tonne on April 1, 2019. 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 British Columbia government is implementing a program (the CleanBC Plan) to partially mitigate the impact of the carbon tax increases on emission intensive trade exposed (EITE) sectors. The Saskatchewan government has released a regulation that applies to facilities emitting more than 25 kilotonnes of CO_2e annually and will require the North Tangleflags in situ heavy crude oil facility and the Senlac in situ heavy crude oil facility to meet reduction targets for GHG emissions effective 2019. The government of Canada has determined that a federal "backstop" carbon pricing system will apply beginning in 2019 in specific provinces and territories within Canada, including the provinces of Saskatchewan and Manitoba in which the Company operates. The federal backstop system will consist of an output-based pricing system for facilities that emit more than 25 kilotonnes CO2e annually, and a fuel charge that applies to facilities with emissions below this level.

The International Maritime Organization (IMO) will implement a new regulation (IMO 2020) effective January 1, 2020, that places sulphur content limits (currently 3.5% to 0.5%) on marine fuel oil consumed by vessels. In our North American operations, IMO 2020 is anticipated to have a net positive impact due to SCO from the Company's Oil Sands Mining and Upgrading operations, a large percentage of which can be processed and refined into low-sulphur diesel.

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 regulatory and 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.

During the fourth quarter of 2018, the Gabonese Republic approved cessation of production from the Company's Olowi Field and associated decommissioning obligations, as well as the terms of termination of the Olowi Production Sharing Contract and the surrender of the permit area back to the government.

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 price for 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, government mandated curtailment, the availability of alternate fuel sources and weather conditions, and other factors. Natural gas prices realized by the Company are affected primarily in North America by supply and demand, weather conditions, industrial demand and the ability to secure adequate transportation for products which could also be affected by pipeline constraints, government mandated curtailment, and prices of alternate sources of energy. Crude oil and natural gas producers in Canada may receive discounted prices for their production relative to international prices due in part to constraints on the ability to transport and sell products to international markets. A failure to resolve such constraints may result in continued discounted or reduced commodity prices realized by crude oil and natural gas producers, including the Company.

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, 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 24% of the Company's 2018 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.

Principal Documents Exhibits

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 expenses due to the integration of the various component parts.

The Company's business also carries risks associated with environmental and safety performance, which are closely scrutinized by governments, the public and the media, and could result in the suspension of or the inability to obtain regulatory approvals and permits, or, in the case of a major incident, fines, civil suits, and/or criminal charges against the Company.

The jurisdictions where Canadian Natural operates are subject to labour legislation and regulations that if changed may impact its operations. In addition, labour risk associated with work interruptions and the securing of necessary manpower may impact the timely and cost effective manner in which projects are completed.

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 compliance, 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, including the following:

l Greenhouse Gas Emissions Management

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 international, national, federal and provincial level. In Canada, the government of Alberta has proceeded with implementing the measures in the Climate Leadership Plan that were announced in 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. The Canadian government and certain provincial governments have published regulations to reduce methane emissions from the oil and natural gas sector, in support of a joint commitment made by the US and Canadian governments to lower emissions from the sector by 2025.

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.

l Air Emissions Management

The Company could face additional costs to retrofit certain equipment to meet the requirements of the federal Multi-Sector Air Pollutants Regulations in Canada. Additional costs may be required to retrofit other equipment in specific regions to meet ambient air quality objectives, as part of regional air zone management.

l Tailings Management

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.

In 2018, the Company continued to implement and adhere to the conditions stipulated in the approved Tailings Management Plans for the Horizon Mine (the "Horizon TMP"), and the AOSP's Muskeg River Mine and Jackpine Mine and thereby met the requirements of the government of Alberta’s Tailings Management Framework (2015) and the Alberta Energy Regulator’s Directive 85. In the future, there is the potential risk of deviating above the approved site-specific tailings profiles resulting in the requirement to post additional security under the Mining Financial Security Plan as well as the potential application of a compliance levy.

In September 2018, the Company acquired the Joslyn oil sands project (now referred to as “Horizon South”). Prior to development, the AER requires the Company to prepare an updated mine plan that will incorporate tailings and closure planning considerations by November 13, 2019. As a result, it is anticipated that, in 2019, further updates will be required to the Horizon TMP to integrate the development of Horizon South.

In December 2018, Alberta Environment and Parks released the new Dam and Canal Safety Directive (the "Directive"). The Directive outlines a detailed process for all fluid holding infrastructure in Alberta (including tailings ponds), on application requirements, performance monitoring and reporting, and decommissioning and closure process. The Company is working with the regulator to determine how the Directive will be implemented and enforced. Muskeg River Mine has obtained several authorizations as it works through the decommissioning process for its External Tailings Facility, reducing the mine's environmental risk and liability.

l Regulatory and Policy Effectiveness

The Company operates under government regulation and policy for the crude oil and natural gas sector including, land tenure, royalties, taxes, production rates, environmental management, and safety performance. Before proceeding with major projects, the Company must follow a determined regulatory process to obtain project approvals and permits. These processes may include Indigenous and stakeholder consultation, environmental impact assessments and public hearings. Canadian Natural’s project execution and timelines could be impacted by delays experienced through the regulatory processes or by conditions placed on its operations through permit approvals. Changes in government policy, such as the federal government’s Bill-69, have the potential to impact the certainty and timelines for the regulatory process on large energy projects, including increased requirements for Indigenous consultation. The Company is working with industry peers, CAPP and others to ensure that its concerns regarding Bill C-69 are communicated to the Canadian government.

l Land Use, Water and Wildlife Management

Legislation and policies related to land management may affect development and operations risk through changes in regional limits on operating standards for air emissions, water use, land disturbance and reclamation. Land planning is used to set aside areas for conservation, reclamation and biodiversity that places limits on crude oil and natural gas development. Management frameworks establish limits and triggers for surface and ground water quality and quantity, land disturbance and air emissions that could increase the standards for operation of facilities.

Water licencing, use and release standards are becoming increasingly stringent both in the process of obtaining access to water and to manage it efficiently. Sub-basin water use licence restrictions and the inability to manage allocations of water licences effectively by transferring water to alternate uses has the potential to increase production expenses. Alberta Wetland Policy changes may increase requirements and payments for new project development.

The Species at Risk Act (Canada) requires the maintenance of habitat for a variety of species. In the case of Woodland Caribou, the requirements of undisturbed habitat combined with minimum herd population from all cumulative land changes may impact plans for crude oil and natural gas expansion. The presence of other species at risk such as birds or amphibians requires that operations be managed to avoid or mitigate effects resulting in potential operational inefficiencies and delays.

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 cash flow is 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, both internal and external, beyond the Company’s control. 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. In general, estimates of economically recoverable crude oil, natural gas and NGLs reserves and the future net revenue 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 royalty regimes, environmental and other 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 revenues 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 Security

The nature and complexity of information security risks that may negatively impact the Company continues to evolve as cyber criminals develop new schemes to target businesses and perpetrate cyber-related frauds that target the information technology and business systems of the Company. 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 cybersecurity risks include cyber-related fraud and theft or destruction of financial and other assets of the Company whereby perpetrators attempt to spoof, manipulate, or take control of electronic communications from Company executives, suppliers, or other business partners, to divert payments and assets to accounts controlled by perpetrators of the scheme. A successful cyber-related fraud of this nature could result in the financial losses to the Company, remediation and recovery costs, and reputational issues with suppliers, customers and business partners who may also be impacted by the scheme. The Company has implemented training programs that allow personnel to identify potential threats of this nature in addition to the internal accounting and process controls implemented 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 to repay the indebtedness of the Company.

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

For the year ended December 31, 2018, 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, 2018 and a preparation date of February 4, 2019. 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 Oil Sands Mining and Upgrading 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 98 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, 2018
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	97	248	311	6,091	3,477	101	7,541
Developed Non-Producing	14	16	—	123	—	326	10	218
Undeveloped	66	69	57	1,106	—	2,794	156	1,920
Total Proved	194	182	305	1,540	6,091	6,597	267	9,679
Probable	74	70	140	1,519	941	3,036	130	3,379
Total Proved plus Probable	268	252	445	3,059	7,032	9,633	397	13,058
North Sea								
Proved								
Developed Producing	34					23		38
Developed Non-Producing	4					—		4
Undeveloped	81					4		82
Total Proved	119					27		124
Probable	67					11		69
Total Proved plus Probable	186					38		193
Offshore Africa								
Proved								
Developed Producing	41					17		44
Developed Non-Producing	—					—		—
Undeveloped	45					11		46
Total Proved	86					28		90
Probable	35					35		41
Total Proved plus Probable	121					63		131
Total Company								
Proved								
Developed Producing	189	97	248	311	6,091	3,517	101	7,623
Developed Non-Producing	18	16	—	123	—	326	10	222
Undeveloped	192	69	57	1,106	—	2,809	156	2,048
Total Proved	399	182	305	1,540	6,091	6,652	267	9,893
Probable	176	70	140	1,519	941	3,082	130	3,489

Total Proved plus Probable	575	252	445	3,059	7,032	9,734	397	13,382

Summary of Company Net Reserves
As of December 31, 2018
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	101	81	189	252	5,125	3,183	80	6,358
Developed Non-Producing	12	14	—	104	—	303	8	189
Undeveloped	56	59	48	911	(8)	2,519	131	1,616
Total Proved	169	154	237	1,267	5,117	6,005	219	8,163
Probable	61	57	100	1,210	761	2,676	104	2,740
Total Proved plus Probable	230	211	337	2,477	5,878	8,681	323	10,903
North Sea								
Proved								
Developed Producing	34					23		38
Developed Non-Producing	4					—		4
Undeveloped	81					4		82
Total Proved	119					27		124
Probable	67					11		69
Total Proved plus Probable	186					38		193
Offshore Africa								
Proved								
Developed Producing	36					12		38
Developed Non-Producing	—					—		—
Undeveloped	36					9		38
Total Proved	72					21		76
Probable	26					23		30
Total Proved plus Probable	98					44		106
Total Company								
Proved								
Developed Producing	171	81	189	252	5,125	3,218	80	6,434
Developed Non-Producing	16	14	—	104	—	303	8	193
Undeveloped	173	59	48	911	(8)	2,532	131	1,736
Total Proved	360	154	237	1,267	5,117	6,053	219	8,363
Probable	154	57	100	1,210	761	2,710	104	2,839

Total Proved plus Probable	514	211	337	2,477	5,878	8,763	323	11,202

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 producibility 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 [1]
As of December 31, 2018
Forecast Prices and Costs

MM$	Discount @ 0%	Discount @ 5%	Discount @ 10%	Discount @ 15%	Discount @ 20%	Unit Value Discounted at 10%/year ($/BOE) [2]
North America						
Proved						
Developed Producing	361,010	143,064	82,072	57,648	45,025	12.91
Developed Non-Producing	5,331	3,697	2,945	2,468	2,121	15.58
Undeveloped	39,173	27,921	15,804	9,128	5,416	9.78
Total Proved	405,514	174,682	100,821	69,244	52,562	12.35
Probable	152,532	45,299	20,981	12,563	8,664	7.66
Total Proved plus Probable	558,046	219,981	121,802	81,807	61,226	11.17
North Sea						
Proved						
Developed Producing	(258)	699	956	1,010	1,000	25.16
Developed Non-Producing	78	63	51	41	34	12.75
Undeveloped	4,339	3,320	2,624	2,129	1,764	32.00
Total Proved	4,159	4,082	3,631	3,180	2,798	29.28
Probable	5,129	3,255	2,289	1,732	1,381	33.17
Total Proved plus Probable	9,288	7,337	5,920	4,912	4,179	30.67
Offshore Africa						
Proved						
Developed Producing	1,293	1,265	1,175	1,080	996	30.92
Developed Non-Producing	—	—	—	—	—	
Undeveloped	2,137	1,399	972	707	533	25.58
Total Proved	3,430	2,664	2,147	1,787	1,529	28.25
Probable	2,557	1,656	1,157	860	671	38.57
Total Proved plus Probable	5,987	4,320	3,304	2,647	2,200	31.17
Total Company						
Proved						
Developed Producing	362,045	145,028	84,203	59,738	47,021	13.09
Developed Non-Producing	5,409	3,760	2,996	2,509	2,155	15.52
Undeveloped	45,649	32,640	19,400	11,964	7,713	11.18
Total Proved	413,103	181,428	106,599	74,211	56,889	12.75
Probable	160,218	50,210	24,427	15,155	10,716	8.60
Total Proved plus Probable	573,321	231,638	131,026	89,366	67,605	11.70

(1) Abandonment and reclamation costs included in the calculation of the Future Net Revenue (FNR) 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 Asset Retirement Obligation (ARO) for development existing as at December 31, 2018. The portion of the Company’s estimated ARO included in the reserves FNR is escalated at 2.0% per year after 2019. For additional information, refer to "Additional Information Concerning Future Net Revenue."

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

Principal Documents Exhibits

Summary of Net Present Values of Future Net Revenue After Income Taxes[1] [2]
As of December 31, 2018
Forecast Prices and Costs

MM$	Discount @ 0%	Discount @ 5%	Discount @ 10%	Discount @ 15%	Discount @ 20%
North America					
Proved					
Developed Producing	266,889	107,718	62,772	44,606	35,135
Developed Non-Producing	3,981	2,691	2,123	1,768	1,511
Undeveloped	28,784	19,876	10,827	5,896	3,182
Total Proved	299,654	130,285	75,722	52,270	39,828
Probable	111,673	32,859	15,080	8,958	6,137
Total Proved plus Probable	411,327	163,144	90,802	61,228	45,965
North Sea					
Proved					
Developed Producing	(82)	446	593	627	626
Developed Non-Producing	(103)	(3)	19	22	20
Undeveloped	2,765	2,089	1,652	1,346	1,122
Total Proved	2,580	2,532	2,264	1,995	1,768
Probable	3,105	1,985	1,406	1,072	860
Total Proved plus Probable	5,685	4,517	3,670	3,067	2,628
Offshore Africa					
Proved					
Developed Producing	1,008	1,032	980	914	851
Developed Non-Producing	—	—	—	—	—
Undeveloped	1,624	1,076	754	554	422
Total Proved	2,632	2,108	1,734	1,468	1,273
Probable	1,924	1,253	882	659	518
Total Proved plus Probable	4,556	3,361	2,616	2,127	1,791
Total Company					
Proved					
Developed Producing	267,815	109,196	64,345	46,147	36,612
Developed Non-Producing	3,878	2,688	2,142	1,790	1,531
Undeveloped	33,173	23,041	13,233	7,796	4,726
Total Proved	304,866	134,925	79,720	55,733	42,869
Probable	116,702	36,097	17,368	10,689	7,515
Total Proved plus Probable	421,568	171,022	97,088	66,422	50,384

(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 MD&A for the year ended December 31, 2018.

(2) Abandonment and reclamation costs included in the calculation of the Future Net Revenue (FNR) 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 Asset Retirement Obligation (ARO) for development existing as at December 31, 2018. The portion of the Company's estimated ARO included in the reserves FNR is escalated at 2.0% per year after 2019. For additional information, refer to "Additional Information Concerning Future Net

Revenue."

Principal Documents Exhibits

Additional Information Concerning Future Net Revenue

The following table summarizes the undiscounted future net revenue as at December 31, 2018 using forecast prices and costs. Abandonment and reclamation costs included in the calculation of the future net revenue 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, 2018. The Company's estimated ARO at December 31, 2018 was $12,312 million, unescalated and undiscounted (escalated and discounted at 10%, ARO at December 31, 2018 was $1,456 million). Approximately $8,717 million of this unescalated and undiscounted amount was also included in the future net revenue and is escalated at 2.0% per year after 2019. 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. In addition, the future net revenue for Horizon assets 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.

	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	958,011	1,288,755	13,308	21,629	7,334	10,122	978,653	1,320,506
Royalties	158,276	222,801	28	47	239	352	158,543	223,200
Production Costs	304,520	393,252	5,927	8,659	2,507	2,466	312,954	404,377
Development Costs	76,525	99,931	1,502	1,943	807	932	78,834	102,806
Abandonment and Reclamation Costs – Future Development	416	752	—	—	44	78	460	830
Abandonment and Reclamation Costs – Existing Development	12,760	13,973	1,692	1,692	307	307	14,759	15,972
Future Net Revenue Before Income Taxes	405,514	558,046	4,159	9,288	3,430	5,987	413,103	573,321
Income Taxes	105,860	146,719	1,579	3,603	798	1,431	108,237	151,753
Future Net Revenue After Income Taxes (1)	299,654	411,327	2,580	5,685	2,632	4,556	304,866	421,568

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

The following table summarizes the future net revenue by product type as at December 31, 2018 using forecast prices and costs. 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, 2018, which are not applied at the product type level.

Future Net Revenue By Product Type

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (discounted at 10%/year) (MM$)	Unit Value ($/BOE) (1)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	11,381	22.45
	Primary Heavy Crude Oil (including solution gas)	2,863	18.41
	Pelican Lake Heavy Crude Oil (including solution gas)	4,209	17.71
	Bitumen (Thermal Oil)	15,811	12.48
	Synthetic Crude Oil	66,689	13.03
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	6,852	6.35
	Abandonment and Reclamation Costs – Existing Development	(1,206)	
	Total	106,599	12.75
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	16,865	23.31
	Primary Heavy Crude Oil (including solution gas)	4,038	18.92
	Pelican Lake Heavy Crude Oil (including solution gas)	5,659	16.75
	Bitumen (Thermal Oil)	21,785	8.79
	Synthetic Crude Oil	74,353	12.65
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	9,588	6.10
	Abandonment and Reclamation Costs – Existing Development	(1,262)	
	Total	131,026	11.70

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

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, 2018. The following is a summary of the Sproule price forecast. All prices increase at a rate of 2% per year after 2023.

	2019	2020	2021	2022	2023
Crude Oil and NGLs					
WTI (1) (US$/bbl)	63.00	67.00	70.00	71.40	72.83
WCS (2) (C$/bbl)	59.47	62.31	67.45	69.53	71.66
Canadian Light Sweet (3) (C$/bbl)	75.27	77.89	82.25	84.79	87.39
Cromer LSB (4) (C$/bbl)	75.27	76.89	81.25	83.79	86.39
Edmonton C5+ (5) (C$/bbl)	75.32	80.00	83.75	85.50	87.29
North Sea Brent (6) (US$/bbl)	70.00	72.00	73.00	74.46	75.95
Natural Gas					
AECO (7) (C$/MMBtu)	1.95	2.44	3.00	3.21	3.30
BC Westcoast Station 2 (8) (C$/MMBtu)	1.35	1.94	2.60	2.81	2.90
Henry Hub (9) (US$/MMBtu)	3.00	3.25	3.50	3.57	3.64

(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 0.77 US$/C$ for 2019, and 0.80 US$/C$ after 2019 was used in the 2018 evaluation.

Production and capital costs are escalated at Sproule’s cost inflation rate of 0% per year for 2019 and 2% per year after 2019 for all products.

The Company’s 2018 average pricing, net of blending costs and excluding risk management activities, was $74.20/bbl for light and medium crude oil, $38.98/bbl for primary heavy crude oil, $43.30/bbl for Pelican Lake heavy crude oil, $33.66/bbl for bitumen (thermal oil), $68.61/bbl for SCO, $40.64 for NGLs, and $2.61/Mcf for natural gas.

Reconciliation of Company Gross Reserves
As of December 31, 2018
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, 2017	171	198	327	1,350	5,264	6,730	229	8,661
Discoveries	—	—	—	—	—	—	—	—
Extensions	12	14	—	171	808	122	9	1,034
Infill Drilling	17	6	—	4	—	470	38	143
Improved Recovery	—	—	1	2	—	3	—	4
Acquisitions	3	2	—	—	—	82	4	22
Dispositions	—	(5)	—	—	—	(3)	—	(5)
Economic Factors	—	1	1	—	—	(305)	(4)	(53)
Technical Revisions	10	(2)	(1)	52	175	42	6	247
Production	(19)	(32)	(23)	(39)	(156)	(544)	(15)	(374)
December 31, 2018	194	182	305	1,540	6,091	6,597	267	9,679

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	120	21	124
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	1	—	1
Improved Recovery	—	—	—
Acquisitions	8	—	8
Dispositions	—	—	—
Economic Factors	5	—	5
Technical Revisions	(6)	18	(3)
Production	(9)	(12)	(11)
December 31, 2018	119	27	124

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	83	20	86
Discoveries	—	—	—
Extensions	—	—	—

Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	10					17		13
Production	(7)					(9)		(9)
December 31, 2018	86					28		90

Total Company

December 31, 2017	374	198	327	1,350	5,264	6,771	229	8,871
Discoveries	—	—	—	—	—	—	—	—
Extensions	12	14	—	171	808	122	9	1,034
Infill Drilling	18	6	—	4	—	470	38	144
Improved Recovery	—	—	1	2	—	3	—	4
Acquisitions	11	2	—	—	—	82	4	30
Dispositions	—	(5)	—	—	—	(3)	—	(5)
Economic Factors	5	1	1	—	—	(305)	(4)	(48)
Technical Revisions	14	(2)	(1)	52	175	77	6	257
Production	(35)	(32)	(23)	(39)	(156)	(565)	(15)	(394)
December 31, 2018	399	182	305	1,540	6,091	6,652	267	9,893

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, 2017	68	74	142	1,230	799	2,790	106	2,884
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	7	—	59	71	93	5	162
Infill Drilling	6	2	—	1	—	391	22	97
Improved Recovery	1	—	2	2	—	1	—	4
Acquisitions	1	1	—	403	—	22	1	410
Dispositions	—	(1)	—	—	—	(2)	—	(2)
Economic Factors	(1)	—	—	—	—	(104)	(1)	(19)
Technical Revisions	(5)	(13)	(4)	(176)	71	(155)	(3)	(157)
Production	—	—	—	—	—	—	—	—
December 31, 2018	74	70	140	1,519	941	3,036	130	3,379

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	60	11	61
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	—	—	—
Improved Recovery	—	—	—
Acquisitions	5	—	5
Dispositions	—	—	—
Economic Factors	(5)	—	(5)
Technical Revisions	7	—	8
Production	—	—	—
December 31, 2018	67	11	69

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	42	47	50
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	—	—	—
Improved Recovery	—	—	—

Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	(7)					(12)		(9)
Production	—					—		—
December 31, 2018	35					35		41

Total Company

December 31, 2017	170	74	142	1,230	799	2,848	106	2,995
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	7	—	59	71	93	5	162
Infill Drilling	6	2	—	1	—	391	22	97
Improved Recovery	1	—	2	2	—	1	—	4
Acquisitions	6	1	—	403	—	22	1	415
Dispositions	—	(1)	—	—	—	(2)	—	(2)
Economic Factors	(6)	—	—	—	—	(104)	(1)	(24)
Technical Revisions	(5)	(13)	(4)	(176)	71	(167)	(3)	(158)
Production	—	—	—	—	—	—	—	—
December 31, 2018	176	70	140	1,519	941	3,082	130	3,489

Principal Documents Exhibits

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, 2017	239	272	469	2,580	6,063	9,520	335	11,545
Discoveries	—	—	—	—	—	—	—	—
Extensions	16	21	—	230	879	215	14	1,196
Infill Drilling	23	8	—	5	—	861	60	240
Improved Recovery	1	—	3	4	—	4	—	8
Acquisitions	4	3	—	403	—	104	5	432
Dispositions	—	(6)	—	—	—	(5)	—	(7)
Economic Factors	(1)	1	1	—	—	(409)	(5)	(72)
Technical Revisions	5	(15)	(5)	(124)	246	(113)	3	90
Production	(19)	(32)	(23)	(39)	(156)	(544)	(15)	(374)
December 31, 2018	268	252	445	3,059	7,032	9,633	397	13,058

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	180	32	185
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	1	—	1
Improved Recovery	—	—	—
Acquisitions	13	—	13
Dispositions	—	—	—
Economic Factors	—	—	—
Technical Revisions	1	18	5
Production	(9)	(12)	(11)
December 31, 2018	186	38	193

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	125	67	136
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	—	—	—
Improved Recovery	—	—	—

Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	3					5		4
Production	(7)					(9)		(9)
December 31, 2018	121					63		131

Total Company

December 31, 2017	544	272	469	2,580	6,063	9,619	335	11,866
Discoveries	—	—	—	—	—	—	—	—
Extensions	16	21	—	230	879	215	14	1,196
Infill Drilling	24	8	—	5	—	861	60	241
Improved Recovery	1	—	3	4	—	4	—	8
Acquisitions	17	3	—	403	—	104	5	445
Dispositions	—	(6)	—	—	—	(5)	—	(7)
Economic Factors	(1)	1	1	—	—	(409)	(5)	(72)
Technical Revisions	9	(15)	(5)	(124)	246	(90)	3	99
Production	(35)	(32)	(23)	(39)	(156)	(565)	(15)	(394)
December 31, 2018	575	252	445	3,059	7,032	9,734	397	13,382

(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.

2018 total Proved Crude Oil, Bitumen (Thermal Oil) and NGLs reserves increased by 1,042 MMbbl primarily due to the following:

- Extensions: Increase of 1,014 MMbbl primarily due to the addition of Horizon South to the Horizon oil sands mining and upgrading project (SCO), future Bitumen (Thermal Oil) well pad additions at Primrose and extension drilling/future offset additions at various Primary Heavy Crude Oil, Light Crude Oil and natural gas (NGLs) properties.
- Infill Drilling: Increase of 66 MMbbl primarily due to infill drilling/future offset additions at various Light Crude Oil, Primary Heavy Crude Oil and natural gas (NGLs) properties.
- Improved Recovery: Increase of 3 MMbbl.
- Acquisitions: Increase of 17 MMbbl primarily due to property acquisitions in North America and North Sea core areas.
- Dispositions: Decrease of 5 MMbbl from the Primary Heavy Crude Oil properties.
- Economic Factors: Increase of 3 MMbbl.
- Technical Revisions: Increase of 244 MMbbl primarily due to geological model changes and improved mine/extraction/upgrading performance at the oil sands mining and upgrading projects (SCO) and improved recoveries at Primrose (Bitumen (Thermal Oil)).
- Production: Decrease of 300 MMbbl.

2018 total Proved Natural Gas reserves decreased by 119 Bcf primarily due to the following:

- Extensions: Increase of 122 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Infill Drilling: Increase of 470 Bcf primarily due to infill drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Improved Recovery: Increase of 3 Bcf.
- Acquisitions: Increase of 82 Bcf primarily due to property acquisitions in North America core areas.
- Dispositions: Decrease of 3 Bcf.
- Economic Factors: Decrease of 305 Bcf due to uneconomic reserves in several North America Natural Gas areas.
- Technical Revisions: Increase of 77 Bcf primarily due to overall positive revisions in several North America, North Sea and Offshore Africa core areas as a result of increased recovery.
- Production: Decrease of 565 Bcf.

2018 total Proved plus Probable Crude Oil, Bitumen and NGLs reserves increased by 1,497 MMbbl primarily due to the following:

- Extensions: Increase of 1,160 MMbbl primarily due to the addition of Horizon South to the Horizon oil sands mining and upgrading project (SCO), future Bitumen (Thermal Oil) well pad additions at Primrose and extension drilling/future offset additions at various Primary Heavy Crude Oil, Light Crude Oil and natural gas (NGLs) properties.
- Infill Drilling: Increase of 97 MMbbl primarily due to infill drilling/future offset additions at various Light Crude Oil and natural gas (NGLs) properties.
- Improved Recovery: Increase of 8 MMbbl.
- Acquisitions: Increase of 428 MMbbl primarily due to property acquisitions at Germain (Bitumen (Thermal Oil)) and in North America and North Sea core areas.
- Dispositions: Decrease of 6 MMbbl from the Primary Heavy Crude Oil properties.
- Economic Factors: Decrease of 4 MMbbl.
- Technical Revisions: Increase of 114 MMbbl primarily due to geological model changes and improved mine/extraction/upgrading performance at the oil sands mining and upgrading projects (SCO), partially offset by the 50 year reserves life cutoff at Primrose (Bitumen (Thermal Oil)).
- Production: Decrease of 300 MMbbl.

2018 total Proved plus Probable Natural Gas reserves increased by 115 Bcf primarily due to the following:

-

Extensions: Increase of 215 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.

- Infill Drilling: Increase of 861 Bcf primarily due to infill drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.

- Improved Recovery: Increase of 4 Bcf.
- Acquisitions: Increase of 104 Bcf primarily due to property acquisitions in North America core areas.
- Dispositions: Decrease of 5 Bcf.
- Economic Factors: Decrease of 409 Bcf due to uneconomic reserves in several North America Natural Gas areas.
- Technical Revisions: Decrease of 90 Bcf primarily due to overall negative revisions in the probable category as a result of transfers to proved categories, shut-in of uneconomic fields, and removal of future extension and infill undeveloped reserves in several North America properties because of revised Company development plans.
- Production: Decrease of 565 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)
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
2018								
First Attributed	25	10	—	175	—	518	42	338
Total	192	69	57	1,106	—	2,809	156	2,048

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)
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
2018								
First Attributed	9	8	—	463	359	464	26	942
Total	91	41	28	1,304	359	1,925	96	2,240

The IQRE reserves evaluation report documents the evaluation, assignment and rationale for undeveloped reserves beyond COGE Handbook development timing guidelines.

Bitumen (thermal oil) accounts for 54% of the Company's total proved undeveloped BOE reserves and 58% of the total probable undeveloped BOE reserves. These undeveloped reserves are scheduled to be developed in a staged approach to align with current operational capacities and efficient capital spending commitments over the next fifty years. Bitumen (thermal oil) development plans are continuously reviewed and updated for internal and external factors.

For products other than bitumen (thermal oil), the assignment of some undeveloped reserves beyond the COGE Handbook guidelines is based on Canadian Natural's capital development plan to optimize operations and align capital investments with estimated future net revenue. The extended development timing has no consequential impact on the confidence level associated with the reserves estimate in each category. Rationales for development timing include:

- large capital projects with facility constraints where development plans are designed to optimize operations and deliver supply for the life of the facility;
- resource plays with extensive ongoing development;
- EOR or waterflood projects with ongoing, extensive development opportunity;
- integrated development of several fields with common facilities to ensure the optimum use of capital;
- development plan is a function of prioritizing according to drainage concerns, maximizing capital efficiency and achieving strategic objectives for the Company; and
- deferral of ongoing development motivated by market conditions, capital constraints, and Company strategy, either separately or in combination.

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 "Uncertainty of Reserves Estimates" in the "Risk Factors" section of 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, 2018.

	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$)	Proved plus Probable (MM$)
2019	2,400	2,506	191	194	123	165	2,714	2,865
2020	4,122	4,341	197	203	132	132	4,451	4,676
2021	4,117	4,329	143	147	133	181	4,393	4,657
2022	3,663	3,976	154	158	91	126	3,908	4,260
2023	2,583	3,057	110	138	34	34	2,727	3,229
Thereafter	59,640	81,722	707	1,103	294	294	60,641	83,119
Total	76,525	99,931	1,502	1,943	807	932	78,834	102,806

Note: 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$)	Proved plus Probable (MM$)
26,271	30,985	918	1,033	542	645	27,731	32,663

Management believes that 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.

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, 2018 and 2017.

Region	2018 Average Daily Production Rates		2017 Average Daily Production Rates	
	Crude Oil & NGLs (Mbbl)	Natural Gas (MMcf)	Crude Oil & NGLs (Mbbl)	Natural Gas (MMcf)
North America				
Northeast British Columbia	13	345	13	397
Northwest Alberta	46	667	42	662
Northern Plains	268	194	280	223
Southern Plains	18	282	19	316
Southeast Saskatchewan	6	2	6	3
Oil Sands Mining & Upgrading	426	—	282	—
North America Total	777	1,490	642	1,601
International				
North Sea UK Sector	24	32	23	39
Offshore Africa	20	26	20	22
International Total	44	58	43	61
Company Total	821	1,548	685	1,662

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. In 2018, Canadian Natural agreed to acquire the Pine River plant, operated by a third party, which transaction is currently awaiting regulatory approval. The plant is currently operating at 90 MMcf/d.

Northwest Alberta

This region is located west of Edmonton, Alberta along the border of British Columbia and 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 portfolio of 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.

The Company targets low-risk exploration and development opportunities 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 expenses are low due to the absence of sand production and its associated disposal requirements, as well as the gathering and pipeline facilities in place. 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. In 2018, polymer flood restoration on the acquired lands was completed ahead of schedule and at the end of 2018, approximately 62% 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 180,000 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, SAGD and steamflood processes which results in significant improvements in well productivity and in ultimate bitumen recovery. Pad additions at Primrose continue to be on budget and ahead of schedule.

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. Cost performance remains on budget with the overall project being approximately 94% complete (87% complete as of December 31, 2018). Kirby North's overall capacity of 40,000 bbl/d of SAGD production is targeted for late 2020.

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

Horizon: 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 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 180 megawatts provide power and steam for 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 the third quarter of 2018, the Company acquired the Joslyn oil sands project, adding to the Company's total oil sands mining and upgrading reserves. This incorporation of the Joslyn leases (now, Horizon South) to the mine plan will allow mining to continue south of the previously existing Horizon leases with opportunity for further cost optimizations.

AOSP: 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 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 third party owned 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 2018, the Company produced from 10 crude oil fields.

The northerly fields are centered around the Ninian field where the Company has a 100% operated working interest, having acquired the remaining 12.9% working interest in 2018. The central processing facility is connected to other fields including the Columba 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 10 blocks and part blocks surrounding the Ninian platform.

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 2020.

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 five 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 from West Espoir in 2006. Crude oil from the East and West Espoir fields is produced to an FPSO with the associated natural gas delivered onshore for local power generation through a subsea pipeline.

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 Platforms A and B. In December 2018, the Company ceased production at the Olowi field and expects to complete all decommissioning operations in the first half of 2019.

South Africa

In May 2012, the Company completed the conversion of its 100% owned oil sub-lease in respect of Block 11B/12B (the "Block") off the southeast coast of South Africa into an exploration right for petroleum for this area. The Company currently has a 20% working interest in the Block, having disposed of a 50% interest in its exploration right in 2013 and an additional 30% interest in two separate farm out transactions in 2018. In December 2018, the operator re-entered the suspended Brudpadda exploration well and has subsequently announced the discovery of gas condensate from that prospect on the Block. The Company expects the cost of the current exploration well to be fully carried pursuant to the two farm out transactions completed in 2018. In the event that a commercial crude oil or natural gas discovery occurs resulting in the exploration right being converted into a production right, additional cash payments would be due to the Company at that time.

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, 2018.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	28,803.0	23,377.3	11,819.0	10,517.6	40,622.0	33,894.9
British Columbia	2,042.0	1,780.5	219.0	202.5	2,261.0	1,983.0
Saskatchewan	10,691.0	9,803.6	2,654.0	1,632.0	13,345.0	11,435.6
Manitoba	—	—	236.0	199.9	236.0	199.9
Total Canada	41,536.0	34,961.4	14,928.0	12,552.0	56,464.0	47,513.4
United States Louisiana	—	—	2.0	0.3	2.0	0.3
North Sea UK Sector	1.0	0.7	57.0	53.9	58.0	54.6
Offshore Africa						
Côte d’Ivoire	—	—	26.0	15.1	26.0	15.1
Gabon	—	—	—	—	—	—
Total	41,537.0	34,962.1	15,013.0	12,621.3	56,550.0	47,583.4

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, 2018.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Non-Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	7,619.0	6,019.6	9,637.0	8,379.8	17,256.0	14,399.4
British Columbia	2,326.0	1,953.7	570.0	481.1	2,896.0	2,434.8
Saskatchewan	2,019.0	1,916.7	3,344.0	2,721.6	5,363.0	4,638.3
Manitoba	—	—	70.0	49.4	70.0	49.4
Northwest Territories	69.0	17.3	—	—	69.0	17.3
Total Canada	12,033.0	9,907.3	13,621.0	11,631.9	25,654.0	21,539.2
United States Louisiana	—	—	2.0	0.3	2.0	0.3
North Sea UK Sector	2.0	1.5	19.0	17.4	21.0	18.9
Offshore Africa						
Côte d’Ivoire	—	—	13.0	7.5	13.0	7.5
Gabon	—	—	13.0	12.0	13.0	12.0
Total	12,035.0	9,908.8	13,668.0	11,669.1	25,703.0	21,577.9

Properties With Attributed and No Attributed Reserves

The following table summarizes the Company's landholdings as at December 31, 2018.

Region (thousands of acres)	Proved Properties Gross	Proved Properties Net	Unproved Properties Gross	Unproved Properties Net	Total Acreage Gross	Total Acreage Net	Average Working Interest %
North America							
Northeast British Columbia	763	670	4,813	4,053	5,576	4,723	85 %
Northwest Alberta	1,770	1,348	3,543	2,709	5,313	4,057	76 %
Northern Plains	1,889	1,637	8,279	7,132	10,168	8,769	86 %
Southern Plains	2,533	2,141	3,582	3,124	6,115	5,265	86 %
Southeast Saskatchewan	117	106	124	115	241	221	92 %
Thermal In Situ Oil Sands	108	108	1,653	1,498	1,761	1,606	91 %
Oil Sands Mining & Upgrading	57	49	243	228	300	277	92 %
Non-core Regions	9	3	1,134	416	1,143	419	37 %
Fee Title	70	70	881	877	951	947	100 %
North America Total	7,316	6,132	24,252	20,152	31,568	26,284	83 %
International							
North Sea UK Sector	63	59	65	61	128	120	94 %
Offshore Africa							
Côte d'Ivoire	10	6	91	53	101	59	58 %
Gabon	—	—	152	140	152	140	92 %
South Africa	—	—	4,002	800	4,002	800	20 %
International Total	73	65	4,310	1,054	4,383	1,119	26 %
Company Total	7,389	6,197	28,562	21,206	35,951	27,403	76 %

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 0.7 million net acres attributed to the North America properties which are currently expected to expire by December 31, 2019.

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.

2018 Costs Incurred in Crude Oil, Natural Gas and NGLs Activities

MM$	North America	North Sea	Offshore Africa	Total
Property Acquisitions				
Proved	214	127	—	341
Unproved	340	—	(89)	251
Exploration	116	—	35	151
Development	3,245	110	212	3,567
Add: Net non-cash and other costs [1]	203	(106)	—	97
Costs Incurred	4,118	131	158	4,407

(1) Non-cash and other costs are comprised primarily of changes in ARO, accounting adjustments related to non-cash consideration on acquisition of properties and proceeds on disposition of properties in excess of original cost.

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, 2018 by geographic region along with a general discussion of 2019 activity.

		2018 Exploratory Wells					
		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
North America							
Northeast British Columbia	Gross	4.0	—	—	—	—	4.0
	Net	4.0	—	—	—	—	4.0
Northwest Alberta	Gross	3.0	9.0	—	—	—	12.0
	Net	2.1	3.9	—	—	—	6.0
Northern Plains	Gross	15.0	—	—	—	—	15.0
	Net	14.1	—	—	—	—	14.1
Southern Plains	Gross	—	—	—	—	—	—
	Net	—	—	—	—	—	—
Southeast Saskatchewan	Gross	1.0	—	—	—	—	1.0
	Net	—	—	—	—	—	—
Oil Sands Mining and Upgrading	Gross	—	—	—	—	—	—
	Net	—	—	—	—	—	—
Non-core Regions	Gross	—	—	—	—	—	—
	Net	—	—	—	—	—	—
North America Total	Gross	23.0	9.0	—	—	—	32.0
	Net	20.2	3.9	—	—	—	24.1
North Sea UK Sector	Gross	—	—	—	—	—	—
	Net	—	—	—	—	—	—
Offshore Africa	Gross	—	—	—	—	—	—
	Net	—	—	—	—	—	—
Company Total	Gross	23.0	9.0	—	—	—	32.0
	Net	20.2	3.9	—	—	—	24.1

Principal Documents Exhibits

		2018 Development Wells					
		Crude Oil	Natural Gas	Dry	Service	Stratigraphic	Total
North America							
Northeast British Columbia	Gross	6.0	6.0	—	2.0	—	14.0
	Net	6.0	6.0	—	2.0	—	14.0
Northwest Alberta	Gross	39.0	10.0	—	1.0	—	50.0
	Net	33.6	7.8	—	1.0	—	42.4
Northern Plains	Gross	386.0	—	9.0	73.0	82.0	550.0
	Net	370.6	—	9.0	73.0	69.3	521.9
Southern Plains	Gross	15.0	—	—	—	—	15.0
	Net	13.6	—	—	—	—	13.6
Southeast Saskatchewan	Gross	37.0	—	—	—	—	37.0
	Net	33.2	—	—	—	—	33.2
Oil Sands Mining and Upgrading	Gross	—	—	—	26.0	532.0	558.0
	Net	—	—	—	23.6	445.1	468.7
Non-core Regions	Gross	—	—	—	—	—	—
	Net	—	—	—	—	—	—
North America Total	Gross	483.0	16.0	9.0	102.0	614.0	1,224.0
	Net	457.0	13.8	9.0	99.6	514.4	1,093.8
North Sea UK Sector	Gross	4.0	—	—	1.0	—	5.0
	Net	3.9	—	—	1.0	—	4.9
Offshore Africa	Gross	3.0	—	—	—	—	3.0
	Net	1.7	—	—	—	—	1.7
Company Total	Gross	490.0	16.0	9.0	103.0	614.0	1,232.0
	Net	462.6	13.8	9.0	100.6	514.4	1,100.4

Total success rate for 2018, excluding service and stratigraphic test wells, was 98%.

2019 Activity

Capital expenditures in 2019 are currently targeted to be as follows:

(MM$)	2019
Exploration and Production	
North America natural gas and NGLs	$365
North America crude oil	775
International crude oil	460
Thermal In Situ Oil Sands	545
Net acquisitions, midstream and other	30
Total Exploration and Production	2,175
Oil Sands Mining and Upgrading	
Strategic, project development, environment and technology	505
Sustaining capital	780
Turnarounds, reclamation and other	240
Total Oil Sands Mining and Upgrading	1,525
Total	$3,700

The Company targets to drill the following wells in Exploration and Production for 2019:

- approximately 29 net producer wells in its North America light and medium crude oil operations;
- approximately 58 net producer wells in its primary heavy crude oil operations;
- approximately 5 net producer wells in its North America natural gas operations; and
- 3.9 net producer wells in the North Sea and 0.6 net producer wells at the Baobab field in Côte d'Ivoire.

The 2019 budget targets a base capital program of $3,700 million, including approximately $3,100 million to maintain current production levels and approximately $600 million directed towards long term growth projects. The Company maintains capital flexibility in its 2019 budget. Should market access conditions improve, the Company has the capability to adjust 2019 capital spending.

Production Estimates

The following table illustrates Canadian Natural's estimated 2019 company gross daily proved and probable production reflected in the reserves reports as of December 31, 2018 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	51,258	77,506	62,712	121,545	403,194	1,266	39,956	967,171
North Sea	32,285	—	—	—	—	38	—	38,618
Offshore Africa	20,668	—	—	—	—	27	—	25,168
Total Proved	104,211	77,506	62,712	121,545	403,194	1,331	39,956	1,030,957
PROBABLE								
North America	5,003	5,967	3,288	1,094	27,174	90	4,032	61,558
North Sea	3,904	—	—	—	—	3	—	4,404
Offshore Africa	3,679	—	—	—	—	3	—	4,179
Total Probable	12,586	5,967	3,288	1,094	27,174	96	4,032	70,141

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Production History

	2018				
	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)	52,080	51,570	53,669	54,010	52,840
Netbacks ($/bbl)					
Sales price [2]	$62.68	$73.97	$75.40	$37.83	$62.32
Transportation	2.81	3.88	3.41	3.41	3.38
Royalties	8.50	10.92	12.21	5.18	9.19
Production expenses	21.14	21.44	20.79	20.28	20.90
Netback	$30.23	$37.73	$38.99	$8.96	$28.85
Primary Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	89,176	84,811	91,631	79,678	86,312
Netbacks ($/bbl)					
Sales price [2]	$36.85	$56.33	$50.91	$11.33	$38.98
Transportation	4.51	4.44	4.04	4.37	4.34
Royalties	4.35	6.83	6.73	0.62	4.65
Production expenses	17.03	17.02	15.58	16.85	16.60
Netback	$10.96	$28.04	$24.56	$(10.51)	$13.39
Pelican Lake Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	63,274	63,914	62,727	62,428	63,082
Netbacks ($/bbl)					
Sales price [2]	$41.63	$60.49	$54.57	$12.40	$43.30
Transportation	4.12	4.82	4.78	4.54	4.57
Royalties	8.43	13.34	11.74	0.23	8.71
Production expenses	7.07	6.96	6.43	6.40	6.72
Netback	$22.01	$35.37	$31.62	$1.23	$23.30
Bitumen (Thermal Oil)					
Average daily production (before royalties) (bbl/d)	111,851	104,907	112,542	102,112	107,839
Netbacks ($/bbl)					
Sales price [2]	$32.22	$51.04	$43.54	$7.70	$33.66
Transportation	2.65	2.63	2.39	2.46	2.53
Royalties	2.02	5.04	2.90	(1.94)	2.01
Production expenses	14.62	13.54	11.35	13.28	13.20
Netback	$12.93	$29.83	$26.90	$(6.10)	$15.92
SCO					
Average daily production (before royalties) (bbl/d) [3]	456,076	407,704	394,382	447,048	426,190
Netbacks ($/bbl)					
Sales price [2]	$71.61	$80.17	$81.69	$42.73	$68.61
Transportation	1.54	1.63	1.73	1.56	1.61
Royalties [4]	1.98	4.25	4.31	2.03	3.09
Production expenses [5]	21.37	22.94	19.95	19.97	21.05
Netback	$46.72	$51.35	$55.70	$19.17	$42.86
Natural Gas					
Average daily production (before royalties) (MMcf/d)	1,547	1,485	1,489	1,441	1,490
Netbacks ($/Mcf)					
Sales price [2]	$2.44	$1.69	$1.96	$3.23	$2.33

Transportation	0.49	0.49	0.41	0.40	0.45
Royalties	0.09	0.06	0.04	0.09	0.07
Production expenses	1.31	1.28	1.20	1.23	1.25
Netback	$ 0.55	$ (0.14)	$ 0.31	$ 1.51	$ 0.56

Principal Documents Exhibits

Production History

	2018				
	Q1	Q2	Q3	Q4	Year Ended
Natural Gas Liquids					
Average daily production (before royalties) (bbl/d)	41,079	38,336	39,287	44,826	40,888
Netbacks ($/bbl)					
Sales price (2)	$41.83	$46.04	$45.50	$30.76	$40.64
Transportation	1.47	2.35	2.04	1.96	1.95
Royalties	5.63	6.34	8.07	3.26	5.73
Production expenses	8.75	8.24	8.26	7.01	8.03
Netback	$25.98	$29.11	$27.13	$18.53	$24.93
North Sea Production and Netbacks by Product (1)					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	21,584	24,456	28,702	21,071	23,965
Netbacks ($/bbl)					
Sales price (2)	$79.35	$93.49	$97.77	$78.45	$87.41
Transportation	1.09	0.75	0.95	0.82	0.86
Royalties	0.23	0.17	0.31	0.18	0.22
Production expenses	43.39	35.12	37.32	44.20	39.89
Netback	$34.64	$57.45	$59.19	$33.25	$46.44
Natural Gas					
Average daily production (before royalties) (MMcf/d)	37	30	38	22	32
Netbacks ($/MMcf)					
Sales price (2)	$11.67	$10.32	$12.67	$14.09	$12.08
Transportation	1.30	1.46	1.11	1.33	1.29
Royalties	—	—	—	—	—
Production expenses	4.67	5.81	5.22	5.76	5.29
Netback	$5.70	$3.05	$6.34	$7.00	$5.50
Offshore Africa Production and Netbacks by Product (1)					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	19,438	18,201	18,802	22,185	19,662
Netbacks ($/bbl)					
Sales price (2)	$78.85	$102.57	$98.66	$81.15	$90.95
Transportation	—	—	—	—	—
Royalties	3.19	9.58	8.07	3.00	6.00
Production expenses	30.99	24.78	19.53	32.15	26.34
Netback	$44.67	$68.21	$71.06	$46.00	$58.61
Natural Gas					
Average daily production (before royalties) (MMcf/d)	30	24	26	25	26
Netbacks ($/Mcf)					
Sales price (2)	$6.95	$7.37	$7.78	$7.32	$7.34
Transportation	0.17	0.18	0.18	0.18	0.18
Royalties	0.87	1.17	1.20	0.80	1.00
Production expenses	2.44	3.00	2.69	3.00	2.76
Netback	$3.47	$3.02	$3.71	$3.34	$3.40

(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)

2018 SCO production before royalties excludes 3,093 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.

SELECTED FINANCIAL INFORMATION

(MM$, except per common share information)		2018	2017
Product sales		$22,282	$18,360
Crude oil and NGLs		$20,668	$16,522
Natural gas		$1,614	$1,838
Net earnings (loss)		$2,591	$2,397
Per common share	– basic	$2.13	$2.04
	– diluted	$2.12	$2.03
Adjusted net earnings (loss) from operations (1)		$3,263	$1,403
Per common share	– basic	$2.68	$1.19
	– diluted	$2.67	$1.19
Cash flows from operating activities		$10,121	$7,262
Adjusted funds flow (1)		$9,088	$7,347
Per common share	– basic	$7.46	$6.25
	– diluted	$7.43	$6.21
Total assets		$71,559	$73,867
Total long-term liabilities		$34,823	$35,953
Cash flows used in investing activities		$4,814	$13,102
Net capital expenditures (2)		$4,731	$17,129

(1) A reconciliation and discussion of the usefulness of these non-GAAP measures is provided in the "Financial and Operational Highlights" section of the Company's MD&A for the year ended December 31, 2018.

(2) A reconciliation and discussion of the usefulness of the non-GAAP measure Net Capital Expenditures is provided in the "Net Capital Expenditures" and "Financial and Operational Highlights" sections of the Company's MD&A for the year ended December 31, 2018.

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.

	2018	2017	2016 (1)
Cash dividends declared per common share	$1.34	$1.10	$0.94

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

Note: On March 6, 2019, the Board of Directors approved an increase in the quarterly dividend to $0.375 per common share, beginning with the dividend payable of April 1, 2019.

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”)	Baa2	P-2	Stable
S&P Global Ratings (“S&P”)	BBB+	A-2	Stable
DBRS Limited (“DBRS”)	BBB (high)	—	Stable

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

Credit ratings are intended to provide investors with an independent opinion of the Company's ability to meet its financial obligations as they come due.

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. A "Stable" outlook indicates a low 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-2 by Moody’s indicates a strong ability to repay short-term obligations.

S&P’s credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the S&P rating system, debt securities rated BBB exhibit adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments on the 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 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 "Negative", "Positive" or "Developing" outlook indicates a higher likelihood of a rating change during that time period. A “Stable” outlook indicates a low likelihood of a rating 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 from time to time. Canadian Natural has not made any other payments to the credit rating organizations in the last two years.
MARKET FOR SECURITIES
The Company’s common shares are listed and posted for trading on the TSX and the NYSE under the symbol CNQ.
Set forth below is the trading activity of the Company’s common shares on the TSX in 2018.

	2018 Monthly Historical Trading on TSX			
Month	High	Low	Close	Volume Traded
January	$46.77	$41.90	$41.99	49,987,668
February	$42.53	$36.88	$39.75	61,259,375
March	$41.08	$37.92	$40.50	62,892,872
April	$46.99	$39.15	$46.32	58,059,592
May	$48.73	$43.56	$44.89	74,408,647
June	$47.59	$40.78	$47.45	65,623,723
July	$49.08	$45.82	$47.80	49,987,996
August	$47.69	$43.96	$44.56	46,214,394
September	$45.04	$40.71	$42.20	69,024,990
October	$43.31	$35.31	$36.12	93,076,191
November	$39.55	$32.08	$33.39	86,818,525
December	$38.74	$30.11	$32.94	88,899,978

On May 16, 2018, the Company's application was approved for a Normal Course Issuer Bid ("NCIB") to purchase through the facilities of the TSX, alternative Canadian trading platforms, and the NYSE, up to 61,454,856 common shares, over a 12-month period commencing May 23, 2018 and ending May 22, 2019. The Company's NCIB announced in March 2017 expired on May 22, 2018.
During 2018, the Company purchased for cancellation 30,857,727 common shares at a weighted average price of $41.56 per common share. From January 1, 2019 to March 6, 2019, the Company purchased 4,340,000 common shares at a weighted average price of $35.86 per common share.

Principal Documents Exhibits

DIRECTORS AND EXECUTIVE OFFICERS

The names, municipalities of residence, offices held with the Company and principal occupations of the Directors and Executive 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 20, 2019 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 65)	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 (age 59)	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 74)	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.
Christopher L. Fong Calgary, Alberta Canada	Director (3)(5) (age 69)	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.
Ambassador Gordon D. Giffin Atlanta, Georgia U.S.A	Director (1)(4) (age 69)	Partner and Global Vice Chair, 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.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Wilfred A. Gobert Calgary, Alberta Canada	Director (2)(4)(5) (age 71)	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 (5) (age 61)	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 (3) (age 57)	Officer of the Company. He has served continuously as a director of the Company since February 2018.
Honourable Frank J. McKenna P.C., O.C., O.N.B., Q.C. Cap Pelé, New Brunswick Canada	Director (2)(4) (age 71)	Deputy Chair, TD Bank Group (bank). 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 69)	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 62)	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 continuously 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.
Troy J.P. Andersen Calgary, Alberta Canada	Senior Vice-President, Canadian Conventional Field Operations (age 40)	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.

Principal Documents Exhibits

Name	Position Presently Held	Principal Occupation During Past 5 Years
Corey B. Bieber Calgary, Alberta Canada	Chief Financial Officer and Senior Vice-President, Finance (6) (age 55)	Officer of the Company.
Trevor J. Cassidy Calgary, Alberta Canada	Senior Vice-President, Thermal (age 45)	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.
Réal M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 68)	Officer of the Company.
Darren M. Fichter Calgary, Alberta Canada	Chief Operating Officer, Exploration and Production (age 48)	Officer of the Company.
Allan E. Frankiw Calgary, Alberta Canada	Senior Vice-President, Production (age 62)	Officer of the Company.
Jay E. Froc Calgary, Alberta Canada	Senior Vice-President, Oil Sands Mining and Upgrading (age 53)	Officer of the Company.
Ronald K. Laing Calgary, Alberta Canada	Senior Vice-President, Corporate Development and Land (age 49)	Officer of the Company.
Pamela A. McIntyre Calgary, Alberta Canada	Senior Vice-President, Safety, Risk Management and Innovation (age 56)	Officer of the Company.
Paul M. Mendes Calgary, Alberta Canada	Vice-President, Legal, General Counsel and Corporate Secretary (age 53)	Officer of the Company.

Principal Documents Exhibits

Name	Position Presently Held	Principal Occupation During Past 5 Years
William R. Peterson Calgary, Alberta Canada	Senior Vice-President, Development Operations (age 52)	Officer of the Company.
Kendall W. Stagg Calgary, Alberta Canada	Senior Vice-President, Exploration (age 57)	Officer of the Company.
Scott G. Stauth Calgary, Alberta Canada	Chief Operating Officer, Oil Sands (age 53)	Officer of the Company.
Betty Yee Calgary, Alberta Canada	Vice-President, Land (age 54)	Officer of the Company.
Robin S. Zabek Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 47)	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.
(6) Effective March 29, 2019, Mr. Corey B. Bieber will step back from his role as Chief Financial Officer and Senior Vice-President, Finance and continue with the Company as an Executive Advisor. Mr. Bieber will remain part of the Company's Management Committee. At that time, Mr. Mark A. Stainthorpe will become Chief Financial Officer and Senior Vice-President, Finance and Mr. Ron D. Kim will become Vice-President, Finance and Principal Accounting Officer. Messrs Stainthorpe, and Kim are currently Vice-President, Finance - Capital Markets and Vice-President, Finance - Corporate, respectively.

All directors stand for election at each Annual General Meeting of the Company's Shareholders. All of the current directors were elected to the Board at the last Annual General Meeting of the Company's Shareholders held on May 3, 2018.

As at December 31, 2018, 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 1,202 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. There are currently no legal proceedings to which the Company is or was a party, or that any of its property is or was the subject of, which would be expected to have a material impact on the Company's financial condition and is not aware of any such legal proceedings that are contemplated.

During the year ended December 31, 2018, 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 three most recently completed financial years or during the current financial year 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

During the most recently completed financial year, the Company did not enter into any contracts, nor are there any contracts still in effect, that are material to the Company’s business, other than contracts entered into in the ordinary course of business.

INTERESTS OF EXPERTS

The Company’s independent auditors are PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have issued an independent auditor’s report dated March 6, 2019 in respect of the Company’s consolidated financial statements as at December 31, 2018 and December 31, 2017 and for each of the three years in the period ended December 31, 2018 and the Company’s internal control over financial reporting as at December 31, 2018. 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 is comprised of Ms. C. M. Best, Chair, Messrs. T.W. Faithfull, G. D. Giffin and D. A. Tuer, each of whom is independent and financially literate as those terms are defined under Canadian securities regulations, National Instrument 52-110 and the NYSE listing standards as they pertain to audit committees of listed issuers. 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.

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 2018 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 and Crown Royalty Statements; (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)	2018	2017
Audit fees	$2,597	$2,960
Audit related fees	425	574
Tax fees	443	470
All other fees	30	52
Total	$3,495	$4,056

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

Principal Documents Exhibits

ADDITIONAL INFORMATION

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

Additional information including Directors' and Executive Officers' remuneration and indebtedness, Director nominees standing for re-election, principal holders of the Company's securities, options to purchase the Company's securities and interest of insiders in material transactions is contained in the Company's Notice of Annual and Special Meeting and Information Circular dated March 20, 2019 in connection with the Annual and Special Meeting of Shareholders of Canadian Natural to be held on May 9, 2019 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 MD&A, comparative Consolidated Financial Statements and Supplementary Oil & Gas Information for the most recently completed fiscal year ended December 31, 2018 found on pages 12 to 53, 58 to 97 and 98 to 105 respectively, of the 2018 Annual Report to the Shareholders, which information is incorporated herein by reference.

For additional copies of this AIF, 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, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, 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, 2018, 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, 2018	Canada and USA	—	46,833	1,471	48,304
Sproule International Limited	December 31, 2018	United Kingdom and Offshore Africa	—	9,224	—	9,224
GLJ Petroleum Consultants Ltd.	December 31, 2018	Canada	—	73,498	—	73,498
Total			—	129,555	1,471	131,026

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 judgments 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,
March 6, 2019

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 "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

Sproule International Limited
Calgary, Alberta, Canada,
March 6, 2019

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

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

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

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada,
March 6, 2019

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 "TIM S. MCKAY"
Tim S. McKay
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 "CATHERINE M. BEST"
Catherine M. Best
Independent Director and Chair of the Audit Committee

Dated this 6th day of March, 2019

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.

Canadian Natural Resources Limited
AUDITED CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2018 AND 2017

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, 2018; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2018.

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 "TIM S. MCKAY"	SIGNED "COREY B. BIEBER"	SIGNED "RONALD D. KIM"
Tim S. McKay President	Corey B. Bieber, CA Chief Financial Officer and Senior Vice-President, Finance	Ronald D. Kim, CA Vice-President, Finance - Corporate

Calgary, Alberta, Canada
March 6, 2019

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, 2018. 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, 2018, as stated in their accompanying Report of Independent Registered Public Accounting Firm.

SIGNED “TIM S. MCKAY”	SIGNED “COREY B. BIEBER”
Tim S. McKay	Corey B. Bieber, CA
President	Chief Financial Officer and Senior Vice-President, Finance

Calgary, Alberta, Canada
March 6, 2019

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 and its subsidiaries (together, the "Company") as of December 31, 2018 and 2017, 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, 2018, 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, 2018, 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, 2018 and 2017, and its financial performance and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS"). Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, 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 Controls 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. Those 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 risks 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 provide 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 financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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
March 6, 2019

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

Principal Documents Exhibits

ANNUAL FINANCIAL STATEMENTS
CONSOLIDATED BALANCE SHEETS

As at December 31 (millions of Canadian dollars)	Note	2018	2017
ASSETS			
Current assets			
Cash and cash equivalents		$101	$137
Accounts receivable		1,148	2,397
Current income taxes receivable		—	322
Inventory	5	955	894
Prepaids and other		176	175
Investments	9	524	893
Current portion of other long-term assets	10	116	79
		3,020	4,897
Exploration and evaluation assets	6	2,637	2,632
Property, plant and equipment	7	64,559	65,170
Other long-term assets	10	1,343	1,168
		$71,559	$73,867
LIABILITIES			
Current liabilities			
Accounts payable		$779	$775
Accrued liabilities		2,356	2,597
Current income taxes payable		151	—
Current portion of long-term debt	11	1,141	1,877
Current portion of other long-term liabilities	12	335	1,012
		4,762	6,261
Long-term debt	11	19,482	20,581
Other long-term liabilities	12	3,890	4,397
Deferred income taxes	13	11,451	10,975
		39,585	42,214
SHAREHOLDERS' EQUITY			
Share capital	14	9,323	9,109
Retained earnings		22,529	22,612
Accumulated other comprehensive income (loss)	15	122	(68)
		31,974	31,653
		$71,559	$73,867

Commitments and contingencies (note 20).
Approved by the Board of Directors on March 6, 2019

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

Principal Documents Exhibits

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

(millions of Canadian dollars, except per common share amounts)	Note	2018	2017 [1]	2016 [1]
Product sales	22	$22,282	$18,360	$12,002
Less: royalties		(1,255)	(1,018)	(575)
Revenue		21,027	17,342	11,427
Expenses				
Production		6,464	5,675	4,184
Transportation, blending and feedstock		4,189	3,529	2,822
Depletion, depreciation and amortization	6,7	5,161	5,186	4,858
Administration		325	319	345
Share-based compensation	12	(146)	134	355
Asset retirement obligation accretion	12	186	164	142
Interest and other financing expense	18	739	631	383
Risk management activities	19	(134)	35	33
Foreign exchange loss (gain)		827	(787)	(55)
Gain on acquisition, disposition and revaluation of properties	6,7,8	(452)	(379)	(250)
Loss (gain) from investments	9,10	346	(38)	(327)
		17,505	14,469	12,490
Earnings (loss) before taxes		3,522	2,873	(1,063)
Current income tax expense (recovery)	13	374	(164)	(618)
Deferred income tax expense (recovery)	13	557	640	(241)
Net earnings (loss)		$2,591	$2,397	$(204)
Net earnings (loss) per common share				
Basic	17	$2.13	$2.04	$(0.19)
Diluted	17	$2.12	$2.03	$(0.19)

(1) In connection with adoption of IFRS 15 on January 1, 2018, the Company has reclassified certain comparative amounts in a manner consistent with the presentation adopted for the year ended December 31, 2018 (see note 2).

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

(millions of Canadian dollars)	2018	2017	2016
Net earnings (loss)	$2,591	$2,397	$(204)
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 $nil (2017 – $9 million, 2016 – $3 million)	5	53	(18)
Reclassification to net earnings (loss), net of taxes of $6 million (2017 – $5 million, 2016 – $2 million)	(39)	(33)	(13)
	(34)	20	(31)
Foreign currency translation adjustment			
Translation of net investment	224	(158)	26
Other comprehensive income (loss), net of taxes	190	(138)	(5)
Comprehensive income (loss)	$2,781	$2,259	$(209)

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

For the years ended December 31

(millions of Canadian dollars)	Note	2018	2017	2016
Share capital	14			
Balance – beginning of year		$9,109	$4,671	$4,541
Issued for the acquisition of AOSP and other assets [(1)]	8	—	3,818	—
Issued upon exercise of stock options		332	466	559
Previously recognized liability on stock options exercised for common shares		120	154	117
Purchase of common shares under Normal Course Issuer Bid		(238)	—	—
Return of capital on PrairieSky Royalty Ltd. share distribution		—	—	(546)
Balance – end of year		9,323	9,109	4,671
Retained earnings				
Balance – beginning of year		22,612	21,526	22,765
Net earnings (loss)		2,591	2,397	(204)
Purchase of common shares under Normal Course Issuer Bid	14	(1,044)	—	—
Dividends on common shares	14	(1,630)	(1,311)	(1,035)
Balance – end of year		22,529	22,612	21,526
Accumulated other comprehensive income (loss)	15			
Balance – beginning of year		(68)	70	75
Other comprehensive income (loss), net of taxes		190	(138)	(5)
Balance – end of year		122	(68)	70
Shareholders' equity		$31,974	$31,653	$26,267

(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 8.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31

(millions of Canadian dollars)	Note	2018	2017	2016
Operating activities				
Net earnings (loss)		$2,591	$2,397	$(204)
Non-cash items				
Depletion, depreciation and amortization		5,161	5,186	4,858
Share-based compensation		(146)	134	355
Asset retirement obligation accretion		186	164	142
Unrealized risk management (gain) loss		(35)	37	25
Unrealized foreign exchange loss (gain)		706	(821)	(93)
Realized foreign exchange loss on repayment of US dollar securities		146	—	—
Gain on acquisition, disposition and revaluation of properties		(452)	(379)	(250)
Loss (gain) from investments		374	(11)	(299)
Deferred income tax expense (recovery)		557	640	(241)
Other		(23)	(110)	(32)
Abandonment expenditures		(290)	(274)	(267)
Net change in non-cash working capital	21	1,346	299	(542)
Cash flows from operating activities		10,121	7,262	3,452
Financing activities				
(Repayment) issue of bank credit facilities and commercial paper, net	11,21	(1,595)	2,222	342
Issue of medium-term notes, net	11,21	—	1,791	998
(Repayment) issue of US dollar debt securities, net	11,21	(1,236)	2,733	(834)
Issue of common shares on exercise of stock options		332	466	559
Purchase of common shares under Normal Course Issuer Bid		(1,282)	—	—
Dividends on common shares		(1,562)	(1,252)	(758)
Cash flows (used in) from financing activities		(5,343)	5,960	307
Investing activities				
Net (expenditures) proceeds on exploration and evaluation assets	21	(266)	(124)	6
Net expenditures on property, plant and equipment [(1)]	21	(4,175)	(4,574)	(3,803)
Acquisition of AOSP and other assets, net of cash acquired [(2)]	8	—	(8,630)	—
Investment in other long-term assets		(28)	(87)	(99)
Net change in non-cash working capital	21	(345)	313	85
Cash flows used in investing activities		(4,814)	(13,102)	(3,811)
(Decrease) increase in cash and cash equivalents		(36)	120	(52)
Cash and cash equivalents – beginning of year		137	17	69
Cash and cash equivalents – end of year		$101	$137	$17
Interest paid, net		$911	$725	$617
Income taxes received		$(225)	$(792)	$(444)

(1) 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.

(2) 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 8.

Principal Documents Exhibits

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 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. Changes in the Company's accounting policies are discussed in note 2.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements have been prepared under the historical cost basis, unless otherwise required. The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and wholly owned partnerships. Subsidiaries include 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 and is carried at the lower of cost and net realizable value. Product inventory is comprised of crude oil held for sale, including pipeline linefill and crude oil stored in floating production, storage and offloading vessels. Cost of product inventory 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. Cost for materials and supplies consists of purchase costs and is based on a first-in, first-out or an average cost basis. Net realizable value for materials and supplies is determined by reference to current market prices.

(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 CGU's recoverable amount is the higher of its fair value less costs of disposal and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount 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. The Company adopted IFRS 16 on January 1, 2019 (see note 3).

(K) ASSET RETIREMENT OBLIGATIONS
The Company provides for asset retirement obligations on all of its property, plant and equipment and certain exploration and evaluation assets 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 NGLs and natural gas products is recognized when performance obligations in the sales contract are satisfied and it is probable that the Company will collect the consideration to which it is entitled. Performance obligations are generally satisfied at the point in time when the product is delivered to a location specified in a contract and control passes to the customer. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.
Contracts for sale of the Company’s products generally have terms of less than a year, with certain contracts extending beyond one year. Contracts in North America generally specify delivery of crude oil and NGLs and natural gas throughout the term of the contract. Contracts in the North Sea and Offshore Africa generally specify delivery of crude oil at a point in time.
Sales of the Company’s crude oil and NGLs and natural gas products to customers are made pursuant to contracts based on prevailing commodity pricing at or near the time of delivery and volumes of product delivered. Revenues are typically collected in the month following delivery and accordingly, the Company has elected to apply the practical expedient to not adjust consideration for the effects of a financing component. Purchases and sales of crude oil and

NGLs and natural gas with the same counterparty, made to facilitate sales to customers or potential customers, that are entered into in contemplation of one another, are combined and recorded as non-monetary exchanges and measured at the net settlement amount.

Revenue in the consolidated statement of earnings represents the Company's share of product sales net of royalty payments to governments and other mineral interest owners. The Company discloses the disaggregation of revenues from sales of crude oil and NGLs and natural gas in the segmented information in note 22. 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.

The Company continues to report revenue for the years ended December 31, 2017 and 2016 in accordance with the Company's previous accounting policy for revenue and cost of goods sold as follows:

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.

(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 solely 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, on a forward looking basis, the Company assesses the expected credit losses associated with its financial assets carried at amortized cost. Expected credit losses are measured as the difference between the cash flows that are due to the Company and the cash flows that the Company expects to receive, discounted at the effective interest rate determined at initial recognition. For trade accounts receivable, the Company applies the simplified approach permitted by IFRS 9, which requires expected lifetime credit losses to be recognized from initial recognition of the receivables. To measure expected credit losses, accounts receivable are grouped based on the number of days the receivables have been outstanding and internal credit assessments of the customers. Credit risk for longer-term receivables is assessed based on an external credit rating of the counterparty. For longer-term receivables with credit risk that has not increased significantly since the date of recognition, the Company measures the expected credit loss as the 12-month expected credit loss.

Changes in the provision for expected credit loss are recognized in net earnings.

The Company continues to report impairment of financial assets for the years ended December 31, 2017 and 2016 in accordance with the Company's previous accounting policy for impairment of financial assets as follows:

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. CHANGES IN ACCOUNTING POLICIES

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.

The Company adopted IFRS 15 on January 1, 2018 using the retrospective with cumulative effect method. There were no changes to reported net earnings or retained earnings as a result of adopting IFRS 15. Under the standard, the Company is required to provide additional disclosure of disaggregated revenue by major product type. In connection with adoption of the standard, the Company has reclassified certain comparative amounts in a manner consistent with the presentation adopted for the year ended December 31, 2018 (see note 22).

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. Applying this expedient had no impact to the revenue recognized under the previous revenue accounting standard as all performance obligations had been met and the consideration had been determined.

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 Company retrospectively adopted the amendments to IFRS 9 on January 1, 2018 and elected to apply the limited exemption in IFRS 9 relating to transition for impairment. Accordingly, provisions for impairment have not been restated in the comparative periods. Adoption of the amendment did not have a significant impact on the Company's previous accounting for impairment of financial assets.

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In October 2018, the IASB issued amendments to IFRS 3 "Definition of a Business" that narrowed and clarified the definition of a business. The amendments also permit a simplified assessment of whether an acquired set of activities and assets is a group of assets rather than a business. The amendments are effective January 1, 2020 with earlier adoption permitted. The amendments apply to business combinations after the date of adoption. The Company is assessing the impact of these amendments on its consolidated financial statements.

In October 2018, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" and IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors". The amendments make minor changes to the definition of the term "material" and align the definition across all IFRS Standards. Materiality is used in making judgments related to the preparation of financial statements. The amendments are effective January 1, 2020 with earlier adoption permitted. The Company is assessing the impact of these amendments on its consolidated financial statements.

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 assets 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 has determined that these amendments have no significant impact 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 has determined that this interpretation has no significant impact on its consolidated financial statements.

IFRS 16 "Leases"

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 and requires balance sheet recognition for all leases. Certain short-term (less than 12 months) and low-value leases (as defined in the standard) are exempt from the requirements, and may continue to be treated as an expense. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are exempt from the standard.

The Company will adopt IFRS 16 on January 1, 2019 using the retrospective with cumulative effect method with no impact to opening retained earnings at the date of adoption. In accordance with the transitional provisions in the standard, balances reported in the comparative periods will not be restated.

On initial adoption, the Company intends to use the following practical expedients under the standard. Certain expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- leases with a remaining lease term of less than twelve months as at January 1, 2019 will be treated as short- term leases; and
- exclusion of indirect costs for the measurement of lease assets at the date of initial application.

The Company does not intend to apply any practical expedients pertaining to grandfathering of leases assessed under the previous standard.

On adoption of IFRS 16, the Company will recognize lease assets and liabilities at the present value of the remaining lease payments, discounted using the Company’s applicable borrowing rate on January 1, 2019. The Company expects to report additional lease assets and corresponding liabilities of between $1.5 billion and $1.6 billion. The Company continues to finalize its accounting for leases in accordance with IFRS 16, and the above estimates are subject to change based on finalization of the Company's review of its lease arrangements.

In the statement of earnings, depletion, depreciation and amortization expense and interest expense will increase, with corresponding decreases in production, transportation and administration expenses. The Company does not expect to report a material impact on net earnings. Under the new standard, the Company will report cash outflows for repayment of the principal portion of the lease liability as cash flows from financing activities. The interest portion of the lease payments will continue to be classified as cash flows from operating activities.

Where the Company, acting as the operator, signs a lease on behalf of a joint operation and assumes the legal liability for that lease, the Company will recognize 100% of the related lease asset and lease liability. As the Company recovers its joint operation partners' share of the costs of the lease contract, these recoveries will be recognized in the consolidated statements of earnings.

4. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

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

(A) Crude Oil and Natural Gas Reserves

Purchase price allocations, depletion, depreciation and amortization, 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 estimated 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.

5. INVENTORY

	2018	2017
Product inventory	$297	$285
Materials and supplies	658	609
	$955	$894

The Company recorded a write-down of its product inventory of $13 million from cost to net realizable value as at December 31, 2018 (2017 - $33 million).

Principal Documents Exhibits

6. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2016	$2,306	$ —	$ 76	$ —	$2,382
Additions	144	—	15	—	159
Acquisition of AOSP and other assets (note 8)	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
Additions	245	—	35	222	502
Transfers to property, plant and equipment	(175)	—	—	(222)	(397)
Disposals/derecognitions and other	(4)	—	(89)	(7)	(100)
At December 31, 2018	$2,348	$ —	$ 37	$ 252	$2,637

During the year ended December 31, 2018, the Company acquired a number of exploration and evaluation properties in the Oil Sands Mining and Upgrading and North America Exploration and Production segments.

In the Oil Sands Mining and Upgrading segment, the Company acquired the Joslyn oil sands project including exploration and evaluation assets of $222 million and associated asset retirement obligations of $4 million. Total consideration of $218 million was comprised of $100 million cash on closing with the remaining balance paid equally over each of the next five years. In the fourth quarter of 2018, following integration of the acquired assets into the Horizon mine plan and determination of proved crude oil reserves, the exploration and evaluation assets were transferred to property, plant and equipment. The above amounts are estimates, and may be subject to change based on the receipt of new information.

In the North America Exploration and Production segment, the Company acquired Laricina Energy Ltd., including exploration and evaluation assets of $118 million and property, plant and equipment of $44 million. In addition, the Company also acquired cash of $24 million and deferred income tax assets of $168 million and assumed net working capital liabilities of $18 million, asset retirement obligations of $17 million and notes payable of $48 million. Total purchase consideration was $46 million, resulting in a pre-tax gain of $225 million on the acquisition, representing the excess of the fair value of the net assets acquired compared to total purchase consideration. The Company settled the notes payable immediately following the completion of the acquisition. The transaction was accounted for using the acquisition method of accounting. The above amounts are estimates, and may be subject to change based on the receipt of new information.

The Company also completed two additional farm-out agreements in the Offshore Africa segment to dispose of a combined 30% interest in its exploration right in South Africa, comprised of exploration and evaluation assets of $89 million, including a recovery of $14 million of past incurred costs, for net proceeds of $105 million (US$79 million), resulting in a pre-tax gain of $16 million ($12 million after-tax). The Company retains a 20% working interest in the exploration right following the completion of these farm-out agreements.

Under the terms of the various agreements, in the event of a commercial crude oil discovery on the exploration right and conversion to a production right, additional cash payments of between US$623 million and US$645 million will be made to the Company. In the event of a commercial natural gas discovery on the exploration right and conversion to a production right, additional cash payments of between US$126 million and US$132 million will be made to the Company.

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

7. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 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 8)	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
Additions (2)	2,428	237	212	1,050	13	21	3,961
Transfers from E&E assets	175	—	—	222	—	—	397
Disposals/derecognitions	(412)	(703)	(70)	(209)	—	—	(1,394)
Foreign exchange adjustments and other	—	661	448	—	—	—	1,109
At December 31, 2018	$67,007	$7,321	$5,471	$43,147	$441	$435	$123,822
Accumulated depletion and depreciation							
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
Expense	3,111	257	201	1,557	14	21	5,161
Disposals/derecognitions	(393)	(703)	(70)	(209)	—	—	(1,375)
Foreign exchange adjustments and other	12	528	353	5	—	—	898
At December 31, 2018	$43,881	$5,735	$4,203	$4,981	$138	$325	$59,263
Net book value							
- at December 31, 2018	$23,126	$1,586	$1,268	$38,166	$303	$110	$64,559
- at December 31, 2017	$23,665	$1,473	$1,162	$38,456	$304	$110	$65,170

(1) Additions in Midstream include a pre-tax revaluation gain of $114 million of a previously held joint interest in certain pipeline system assets.

(2) Additions in North Sea include a pre-tax revaluation gain of $19 million relating to acquisitions of its previously held interest.

Project costs not subject to depletion and depreciation	2018	2017
Kirby Thermal Oil Sands – North	$1,424	$944

During the year ended December 31, 2018, the Company acquired a number of producing crude oil and natural gas properties in the North America and North Sea Exploration and Production segments. These transactions were accounted for using the acquisition method of accounting. Gains reported on the acquisitions represent the excess of the fair value of the net assets acquired compared to total purchase consideration.

In North America Exploration and Production, excluding the impact of acquisitions disclosed in note 6, the Company acquired property, plant and equipment for net cash consideration paid of $170 million and assumed associated asset retirement obligations of $13 million. No net deferred income tax liabilities were recognized. The Company recognized a pre-tax gain of $47 million on the transactions.

In connection with the acquisition of the remaining interest in certain operations in the North Sea Exploration and Production segment, the Company acquired $108 million of property, plant and equipment, for net proceeds received of $73 million. The Company also acquired net working capital of $7 million, assumed associated asset retirement obligations of $41 million and recognized net deferred income tax liabilities of $27 million. The Company recognized a pre-tax gain of $120 million on the acquisition and a pre-tax revaluation gain of $19 million relating to its previously held interest.

During the fourth quarter of 2018, the Gabonese Republic agreed to cessation of production from the Company's Olowi field, as well as the terms of termination of the Olowi Production Sharing Contract and the return of the permit area back to the Gabonese Republic, including the associated asset retirement obligations of $69 million. The transaction resulted in a pre-tax gain on disposition of property of $20 million ($14 million after-tax).

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), for net cash consideration of $1,013 million (2016 – $159 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). No net deferred income tax liabilities were recognized on these acquisitions (2016 - $nil).

In connection with the acquisition of pipeline system assets in the Midstream segment in 2017, 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.

As at December 31, 2018, 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 2018, pre-tax interest of $69 million (2017 – $82 million; 2016 – $233 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (2017 – 3.8%; 2016 – 3.9%).

8. 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 20). 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 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) paid 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 11).

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.

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

For the year ended December 31, 2017, 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.

9. INVESTMENTS

As at December 31, 2018 and 2017, the Company had the following investments:

	2018	2017
Investment in PrairieSky Royalty Ltd.	$400	$726
Investment in Inter Pipeline Ltd.	124	167
	$524	$893

Investment in PrairieSky Royalty Ltd.

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, 2018, the Company's investment in PrairieSky Ltd. ("PrairieSky") was classified as a current asset. PrairieSky is in the business of acquiring and managing oil and gas royalty income assets through indirect third-party oil and gas development.

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

	2018	2017	2016
Fair value loss (gain) from PrairieSky	$326	$(3)	$(292)
Dividend income from PrairieSky	(17)	(17)	(27)
	$309	$(20)	$(319)

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 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, 2018, 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:

	2018	2017	2016
Fair value loss from Inter Pipeline	$ 43	$ 23	$ —
Dividend income from Inter Pipeline	(11)	(10)	(1)
	$ 32	$ 13	$ (1)

10. OTHER LONG-TERM ASSETS

	2018	2017
Investment in North West Redwater Partnership	$287	$292
North West Redwater Partnership subordinated debt [(1)]	591	510
Risk management (note 19)	373	204
Other	208	241
	1,459	1,247
Less: current portion	116	79
	$1,343	$1,168

(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 $9,700 million. The Project is currently in the commissioning phase. 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, 2018, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $152 million, for a Company total of $591 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, currently consisting of interest and fees, with principal repayments beginning in 2020 (see note 20). The Company is unconditionally obligated to pay this portion of the cost of service toll over the 30-year tolling period. As at December 31, 2018, the Company had recognized $62 million in prepaid service tolls.

As at December 31, 2018, Redwater Partnership had borrowings of $2,333 million under its secured $3,500 million syndicated credit facility, maturing June 2018. During the first quarter of 2018, 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.

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.

The assets, liabilities, partners’ equity and equity loss (income) related to Redwater Partnership and the Company’s 50% interest at December 31, 2018 and 2017 were comprised as follows:

	2018		2017	
	Redwater Partnership 100% interest	Company 50% interest	Redwater Partnership 100% interest	Company 50% interest
Current assets	$210	$ 105	$330	$ 165
Non-current assets	$11,250	$ 5,625	$10,540	$ 5,270
Current liabilities	$352	$ 176	$2,476	$ 1,238
Non-current liabilities	$10,534	$ 5,267	$7,810	$ 3,905
Partners’ equity	$574	$ 287	$584	$ 292
Equity loss (income)	$10	$ 5	$(62)	$ (31)

11. LONG-TERM DEBT

	2018	2017
Canadian dollar denominated debt, unsecured		
Bank credit facilities	$831	$3,544
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	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	600
4.85% debentures due May 30, 2047	300	300
	6,131	8,844
US dollar denominated debt, unsecured		
Bank credit facilities (December 31, 2018 - US$2,954 million; December 31, 2017 - US$1,839 million)	4,031	2,300
Commercial paper (December 31, 2018 - US$104 million; December 31, 2017 - US$500 million)	141	625
US dollar debt securities		
1.75% due January 15, 2018 (US$600 million)	—	751
5.90% due February 1, 2018 (US$400 million)	—	501
3.45% due November 15, 2021 (US$500 million)	682	625
2.95% due January 15, 2023 (US$1,000 million)	1,364	1,252
3.80% due April 15, 2024 (US$500 million)	682	625
3.90% due February 1, 2025 (US$600 million)	819	751
3.85% due June 1, 2027 (US$1,250 million)	1,706	1,566
7.20% due January 15, 2032 (US$400 million)	546	501
6.45% due June 30, 2033 (US$350 million)	478	438
5.85% due February 1, 2035 (US$350 million)	478	438
6.50% due February 15, 2037 (US$450 million)	614	563
6.25% due March 15, 2038 (US$1,100 million)	1,501	1,377
6.75% due February 1, 2039 (US$400 million)	546	501
4.95% due June 1, 2047 (US$750 million)	1,023	939
	14,611	13,753
Long-term debt before transaction costs and original issue discounts, net	20,742	22,597
Less: original issue discounts, net (1)	17	18
transaction costs (1) (2)	102	121
	20,623	22,458
Less: current portion of commercial paper	141	625
current portion of other long-term debt (1) (2)	1,000	1,252
	$19,482	$20,581

(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, 2018, the Company had in place revolving bank credit facilities of $4,976 million of which $4,723 million was available for use. Additionally, the Company had in place fully drawn term credit facilities of $4,750 million. Details of these facilities are described below. This excludes certain other dedicated credit facilities supporting letters of credit.

- a $100 million demand credit facility;
- a $1,800 million non-revolving term credit facility maturing May 2020;
- a $2,200 million non-revolving term credit facility maturing October 2020;
- a $750 million non-revolving term credit facility maturing February 2021;
- a $2,425 million revolving syndicated credit facility with $330 million maturing in June 2019 and $2,095 million maturing June 2021;
- a $2,425 million revolving syndicated credit facility maturing June 2022; and
- a £15 million demand credit facility related to the Company’s North Sea operations.

During 2018, the Company extended the $2,425 million revolving syndicated credit facility originally due June 2020 to June 2022. Each of the $2,425 million revolving facilities is 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 is repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers’ acceptances, LIBOR, US base rate or Canadian prime rate.

During 2018, the Company repaid and cancelled $1,200 million of the $3,000 million non-revolving term credit facility (third quarter of 2018 – $1,050 million; first quarter of 2018 – $150 million) scheduled to mature in May 2020. The required annual amortization of 5% of the original balance is now satisfied. Borrowings under the term loan facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers’ acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $1,800 million facility was fully drawn.

During 2018, the Company extended the $2,200 million non-revolving credit facility originally due October 2019 to October 2020. Borrowings under the $2,200 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers’ acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $2,200 million facility was fully drawn.

During 2018, the Company repaid and cancelled the $125 million non-revolving term credit facility scheduled to mature in February 2019. The Company also extended the $750 million non-revolving term credit facility originally due February 2019 to February 2021. Borrowings under the $750 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers’ acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $750 million facility was fully drawn.

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, 2018 was 2.6% (December 31, 2017 – 2.2%), and on total long-term debt outstanding for the year ended December 31, 2018 was 3.9% (December 31, 2017 – 3.8%).

As at December 31, 2018, letters of credit and guarantees aggregating to $450 million were outstanding.

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.

US Dollar Debt Securities

During 2018, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

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.

Scheduled Debt Repayments

Scheduled debt repayments are as follows:

Year	Repayment
2019	$ 1,141
2020	$ 5,996
2021	$ 1,444
2022	$ 1,003
2023	$ 1,365
Thereafter	$ 9,793

Principal Documents Exhibits

12. OTHER LONG-TERM LIABILITIES

	2018	2017
Asset retirement obligations	$3,886	$4,327
Share-based compensation	124	414
Risk management (note 19)	17	103
Deferred purchase consideration (1) (2)	118	469
Other	80	96
	4,225	5,409
Less: current portion	335	1,012
	$3,890	$4,397

(1) Includes $118 million of deferred purchase consideration at December 31, 2018, payable in annual installments of $25 million over the next five years.
(2) Includes $469 million (US$375 million) of deferred purchase consideration at December 31, 2017, paid 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 5.0% (2017 – 4.7%; 2016 – 5.2%) and inflation rates of up to 2% (December 31, 2017 - up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	2018	2017	2016
Balance – beginning of year	$4,327	$3,243	$2,950
Liabilities incurred	19	12	3
Liabilities acquired, net	6	784	30
Liabilities settled	(290)	(274)	(267)
Asset retirement obligation accretion	186	164	142
Revision of cost, inflation rates and timing estimates	(111)	(40)	(68)
Change in discount rate	(334)	509	493
Foreign exchange adjustments	83	(71)	(40)
Balance – end of year	3,886	4,327	3,243
Less: current portion	186	92	95
	$3,700	$4,235	$3,148

Segmented Asset Retirement Obligations

	2018	2017
Exploration and Production		
North America	$1,665	$1,840
North Sea	707	755
Offshore Africa	134	245
Oil Sands Mining and Upgrading	1,379	1,486
Midstream	1	1
	$3,886	$4,327

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.

	2018	2017	2016
Balance – beginning of year	$414	$426	$128
Share-based compensation (recovery) expense	(146)	134	355
Cash payment for stock options surrendered	(5)	(6)	(7)
Transferred to common shares	(120)	(154)	(117)
(Recovered from) charged to Oil Sands Mining and Upgrading, net	(19)	14	67
Balance – end of year	124	414	426
Less: current portion	92	348	368
	$32	$66	$58

Included within share-based compensation liability as at December 31, 2018 was $13 million (2017 – $5 million; 2016 – $nil) related to performance share units 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:

	2018	2017	2016
Fair value	$3.33	$11.82	$11.41
Share price	$32.94	$44.92	$42.79
Expected volatility	27.4%	27.1%	30.7%
Expected dividend yield	4.1%	2.5%	2.3%
Risk free interest rate	1.9%	1.8%	0.9%
Expected forfeiture rate	4.2%	5.0%	5.0%
Expected stock option life (1)	4.4 years	4.5 years	4.6 years

(1) At original time of grant.

The intrinsic value of vested stock options at December 31, 2018 was $27 million (2017 – $195 million; 2016 – $191 million).

13. INCOME TAXES

The provision for income tax was as follows:

Expense (recovery)	2018	2017	2016
Current corporate income tax – North America	$312	$(145)	$(377)
Current corporate income tax – North Sea	28	57	(74)
Current corporate income tax – Offshore Africa	54	45	22
Current PRT [1] – North Sea	(29)	(132)	(198)
Other taxes	9	11	9
Current income tax	374	(164)	(618)
Deferred corporate income tax	540	586	(106)
Deferred PRT [1] – North Sea	17	54	(135)
Deferred income tax	557	640	(241)
Income tax	$931	$476	$(859)

(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:

	2018	2017	2016
Canadian statutory income tax rate	27.0%	27.0%	27.0%
Income tax provision at statutory rate	$ 951	$ 776	$ (287)
Effect on income taxes of:			
UK PRT and other taxes	(3)	(67)	(324)
Impact of deductible UK PRT and other taxes on corporate income tax	3	28	131
Foreign and domestic tax rate differentials	6	(43)	(54)
Non-taxable portion of capital gains/losses	142	(86)	(80)
Stock options exercised for common shares	(41)	33	94
Income tax rate and other legislative changes	—	10	(107)
Non-taxable gain on corporate acquisitions	(119)	(63)	—
Revisions arising from prior year tax filings	(136)	(3)	(120)
Change in unrecognized capital loss carryforward asset	142	(86)	(80)
Other	(14)	(23)	(32)
Income tax expense (recovery)	$ 931	$ 476	$ (859)

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

	2018	2017
Deferred income tax liabilities		
Property, plant and equipment and exploration and evaluation assets	$12,885	$12,484
Unrealized risk management activities	33	20
PRT deduction for corporate income tax	1	7
Investments	46	96
Investment in North West Redwater Partnership	414	252
Other	174	—
	13,553	12,859
Deferred income tax assets		
Asset retirement obligations	(1,142)	(1,264)
Loss carryforwards	(855)	(523)
Unrealized foreign exchange loss on long-term debt	(104)	(29)
Deferred PRT	(1)	(18)
Other	—	(50)
	(2,102)	(1,884)
Net deferred income tax liability	$11,451	$10,975

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

	2018	2017	2016
Property, plant and equipment and exploration and evaluation assets	$281	$541	$37
Timing of partnership items	—	—	(261)
Unrealized foreign exchange (gain) loss on long-term debt	(75)	120	63
Unrealized risk management activities	18	(46)	(44)
Asset retirement obligations	175	(88)	(20)
Loss carryforwards	(61)	48	(221)
Investments	(50)	(2)	38
Investment in North West Redwater Partnership	162	30	81
Deferred PRT	17	54	(135)
PRT deduction for corporate income tax	(7)	(21)	61
Other	97	4	160
	$557	$640	$(241)

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

	2018	2017	2016
Balance – beginning of year	$10,975	$9,073	$9,344
Deferred income tax expense (recovery)	557	640	(241)
Deferred income tax (recovery) expense included in other comprehensive income	(6)	4	(5)
Foreign exchange adjustments	41	(29)	(25)
Business combinations (note 6,7,8)	(116)	1,287	—
Balance – end of year	$11,451	$10,975	$9,073

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.

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 $750 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.

Principal Documents Exhibits

14. SHARE CAPITAL
Authorized
Preferred shares issuable in a series.
Unlimited number of common shares without par value.

Issued Common shares	2018 Number of shares (thousands)	2018 Amount	2017 Number of shares (thousands)	2017 Amount
Balance – beginning of year	1,222,769	$ 9,109	1,110,952	$ 4,671
Issued for the acquisition of AOSP and other assets (note 8)	—	—	97,561	3,818
Issued upon exercise of stock options	9,975	332	14,256	466
Previously recognized liability on stock options exercised for common shares	—	120	—	154
Purchase of common shares under Normal Course Issuer Bid	(30,858)	(238)	—	—
Balance – end of year	1,201,886	$ 9,323	1,222,769	$ 9,109

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 March 6, 2019, the Board of Directors declared a quarterly dividend of $0.375 per common share, an increase from the previous quarterly dividend of $0.335 per common share. The dividend is payable on April 1, 2019. 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.
Normal Course Issuer Bid
On May 16, 2018, 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 61,454,856 common shares, over a 12-month period commencing May 23, 2018 and ending May 22, 2019. The Company's Normal Course Issuer Bid announced in March 2017 expired on May 22, 2018.
For the year ended December 31, 2018, the Company purchased 30,857,727 common shares at a weighted average price of $41.56 per common share for a total cost of $1,282 million. Retained earnings were reduced by $1,044 million, representing the excess of the purchase price of common shares over their average carrying value. During 2017 and 2016, the Company did not purchase any common shares for cancellation. Subsequent to December 31, 2018, the Company purchased 4,340,000 common shares at a weighted average price of $35.86 per common share for a total cost of $156 million.
Stock Options
The Company’s Option Plan provides for the granting of stock options to employees. Stock options granted under the Option Plan have terms ranging from five to six years to expiry and vest over a five-year period. The exercise price of each stock option granted is determined at the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the grant. Each stock option granted provides the holder the choice to purchase one common share of the Company at the stated exercise price or receive a cash payment equal to the difference between the stated exercise price and the market price of the Company’s common shares on the date of surrender of the stock

option.

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

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The following table summarizes information relating to stock options outstanding at December 31, 2018 and 2017:

	2018		2017	
	Stock options (thousands)	Weighted average exercise price	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	56,036	$ 36.67	58,299	$ 34.22
Granted	4,256	$ 43.75	16,052	$ 42.07
Surrendered for cash settlement	(392)	$ 33.46	(626)	$ 33.18
Exercised for common shares	(9,975)	$ 33.28	(14,256)	$ 32.66
Forfeited	(3,240)	$ 38.76	(3,433)	$ 37.53
Outstanding – end of year	46,685	$ 37.92	56,036	$ 36.67
Exercisable – end of year	19,436	$ 36.03	18,282	$ 34.25

The range of exercise prices of stock options outstanding and exercisable at December 31, 2018 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	3,120	2.04	$ 22.90	1,515	$ 22.90
$25.00-$29.99	5,112	2.02	$ 28.86	2,453	$ 28.87
$30.00-$34.99	6,013	0.83	$ 33.27	4,831	$ 33.43
$35.00-$39.99	11,304	2.72	$ 37.46	4,131	$ 35.91
$40.00-$44.99	17,107	3.23	$ 43.59	5,664	$ 43.60
$45.00-$46.74	4,029	4.06	$ 45.20	842	$ 45.08
	46,685	2.66	$ 37.92	19,436	$ 36.03

15. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	2018	2017
Derivative financial instruments designated as cash flow hedges	$13	$47
Foreign currency translation adjustment	109	(115)
	$122	$(68)

16. CAPITAL DISCLOSURES

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, 2018, the ratio was within the target range at 39%.

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.

	2018	2017
Long-term debt, net [1]	$20,522	$22,321
Total shareholders' equity	$31,974	$31,653
Debt to book capitalization	39%	41%

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

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. At December 31, 2018, the Company was in compliance with this covenant.

17. NET EARNINGS (LOSS) PER COMMON SHARE

	2018	2017	2016
Weighted average common shares outstanding – basic (thousands of shares)	1,218,798	1,175,094	1,100,471
Effect of dilutive stock options (thousands of shares)	4,960	7,729	—
Weighted average common shares outstanding – diluted (thousands of shares)	1,223,758	1,182,823	1,100,471
Net earnings (loss)	$ 2,591	$ 2,397	$ (204)
Net earnings (loss) per common share – basic	$ 2.13	$ 2.04	$ (0.19)
– diluted	$ 2.12	$ 2.03	$ (0.19)

In 2018, the Company excluded 23,458,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share (year ended December 31, 2017 - 17,547,000).

18. INTEREST AND OTHER FINANCING EXPENSE

	2018	2017	2016
Interest and other financing expense:			
Long-term debt	$867	$810	$664
Less: amounts capitalized on qualifying assets	69	82	233
Total interest and other financing expense	798	728	431
Total interest income	(59)	(97)	(48)
Net interest and other financing expense	$739	$631	$383

19. FINANCIAL INSTRUMENTS

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

2018					
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	$1,148	$ —	$ —	$ —	$1,148
Investments	—	524	—	—	524
Other long-term assets	591	12	361	—	964
Accounts payable	—	—	—	(779)	(779)
Accrued liabilities	—	—	—	(2,356)	(2,356)
Other long-term liabilities [1]	—	(17)	—	(118)	(135)
Long-term debt [2]	—	—	—	(20,623)	(20,623)
	$1,739	$ 519	$ 361	$ (23,876)	$ (21,257)

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 [3]	—	(38)	(65)	(469)	(572)
Long-term debt [2]	—	—	—	(22,458)	(22,458)
	$2,907	$ 855	$ 139	$ (26,299)	$ (22,398)

(1) Includes $118 million of deferred purchase consideration payable over the next five years.

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

(3) Includes $469 million (US$375 million) of deferred purchase consideration which was paid to Marathon in March 2018.

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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:

	2018 Carrying amount	Fair value		
Asset (liability) [1] [2]		Level 1	Level 2	Level 3 [4] [5]
Investments [3]	$524	$524	$—	$—
Other long-term assets	$964	$—	$373	$591
Other long-term liabilities	$(135)	$—	$(17)	$(118)
Fixed rate long-term debt [6] [7]	$(15,620)	$(15,952)	$—	$—

	2017 Carrying amount	Fair value		
Asset (liability) [1] [2]		Level 1	Level 2	Level 3 [5]
Investments [3]	$893	$893	$—	$—
Other long-term assets	$714	$—	$204	$510
Other long-term liabilities	$(103)	$—	$(103)	$—
Fixed rate long-term debt [6] [7]	$(15,989)	$(17,259)	$—	$—

(1) Excludes financial assets and liabilities where the carrying amount approximates fair value due to the short-term nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and purchase consideration paid to Marathon in March 2018).
(2) There were no transfers between Level 1, 2 and 3 financial instruments.
(3) The fair values of the investments are based on quoted market prices.
(4) The fair value of the deferred purchase consideration is based on the present value of future cash payments.
(5) The fair value of Redwater Partnership subordinated debt is based on the present value of future cash receipts.
(6) The fair value of fixed rate long-term debt has been determined based on quoted market prices.
(7) Includes the current portion of fixed rate long-term debt.

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 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)	2018	2017
Derivatives held for trading		
Foreign currency forward contracts	$8	$(38)
Crude oil WCS [1] differential swaps	(17)	—
Natural gas AECO basis swaps	1	—
Natural gas AECO fixed price swaps	3	—
Cash flow hedges		
Foreign currency forward contracts	70	(71)
Cross currency swaps	291	210
	$356	$101

Included within:		
Current portion of other long-term assets	$92	$—
Current portion of other long-term liabilities	(17)	(103)
Other long-term assets	281	204
	$356	$101

(1) Western Canadian Select.

During 2018, the Company recognized a gain of $2 million (2017 – gain of $5 million, 2016 – gain of $7 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.

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)	2018	2017
Balance – beginning of year	$101	$489
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	35	(37)
Foreign exchange	260	(375)
Other comprehensive (loss) income	(40)	24
Balance – end of year	356	101
Less: current portion	75	(103)
	$281	$204

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

	2018	2017	2016
Net realized risk management (gain) loss	$(99)	$ (2)	$ 8
Net unrealized risk management (gain) loss	(35)	37	25
	$(134)	$ 35	$ 33

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, 2018, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

	Remaining term	Volume	Weighted average price	Index
Crude Oil				
WCS differential swaps	Jan 2019 - Mar 2019	28,000 bbl/d	US$17.65	WCS
WCS differential swaps	Jan 2019 - Sep 2019	8,000 bbl/d	US$23.57	WCS
Natural Gas				
AECO basis swaps	Jan 2019 - Mar 2019	10,000 MMbtu/d	US$1.39	AECO
AECO fixed price swaps	Jan 2019 - Mar 2019	30,000 GJ/d	$2.30	AECO
AECO fixed price swaps (1)	Apr 2019 - Oct 2019	10,000 GJ/d	$1.30	AECO

(1) As at March 6, 2019, the Company has hedged an additional 105,000 GJ/d of currently forecasted natural gas volumes using AECO fixed price swaps, at a weighted average price of $1.32/GJ, for April to October 2019.

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. 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, 2018, 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, 2018 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 2019 — Nov 2021	US$500	1.022	3.45 %	3.96 %
	Jan 2019 — Mar 2038	US$550	1.170	6.25 %	5.76 %

All cross currency swap derivative financial instruments were designated as hedges at December 31, 2018 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2018 the Company had US$3,506 million of foreign currency forward contracts outstanding, with terms of up to 90 days, including US$3,058 million designated as cash flow hedges.

Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company’s 2018 net earnings and other comprehensive income (loss) to changes in the fair value of financial instruments outstanding as at December 31, 2018, 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.

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	2018		2017	
	Increase (decrease) to net earnings	Increase (decrease) to other comprehensive income	Increase (decrease) to net earnings	(Increase) decrease to other comprehensive loss
Commodity price risk [1]				
Increase WCS differential US$1.00/bbl	$(5)	$ —	$—	$ —
Decrease WCS differential US$1.00/bbl	$5	$ —	$—	$ —
Increase AECO $0.10/Mcf [2]	$(1)	$ —	$—	$ —
Decrease AECO $0.10/Mcf [2]	$1	$ —	$—	$ —
Interest rate risk				
Increase interest rate 1%	$(33)	$ (21)	$(42)	$ (16)
Decrease interest rate 1%	$33	$ 25	$42	$ 19
Foreign currency exchange rate risk				
Increase exchange rate by US$0.01	$(114)	$ —	$(105)	$ —
Decrease exchange rate by US$0.01	$113	$ —	$101	$ —

(1) Based on the Company's contracted AECO basis swap volumes at December 31, 2018, a movement of US$0.10/Mcf would not have a significant impact on net earnings or other comprehensive income.

(2) Movements in AECO are based on the Company's contracted AECO fixed price swap volumes at December 31, 2018.

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, 2018, substantially all of the Company’s accounts receivable were due within normal trade terms and the average expected credit loss was approximately 1% of the Company's accounts receivable balance.
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, 2018, the Company had net risk management assets of $361 million with specific counterparties related to derivative financial instruments (December 31, 2017 – $187 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 of the Company’s financial liabilities were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$779	$—	$—	$ —
Accrued liabilities	$2,356	$—	$—	$ —
Other long-term liabilities	$42	$24	$69	$ —
Long-term debt (1) (2)	$1,141	$5,996	$3,812	$ 9,793

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

(2) 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, $836 million; one to less than two years, $755 million; two to less than five years, $1,668 million; and thereafter, $5,327 million. Interest payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2018.

20. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2019	2020	2021	2022	2023	Thereafter
Product transportation and pipeline	$692	$664	$620	$516	$381	$ 3,991
North West Redwater Partnership service toll (1)	$86	$126	$157	$158	$157	$ 2,858
Offshore equipment operating leases	$94	$73	$75	$8	$—	$ —
Office leases	$42	$42	$39	$31	$32	$ 89
Other	$85	$35	$32	$32	$31	$ 424

(1) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, which currently consists of interest and fees, with principal repayments beginning in 2020. Included in the service toll is $1,301 million of interest payable over the 30 year tolling period. See note 10.

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.

21. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	2018	2017	2016
Changes in non-cash working capital			
Accounts receivable	$1,233	$(977)	$(142)
Current income tax assets (liabilities)	471	527	(165)
Inventory	(74)	81	(79)
Prepaids and other	(3)	(28)	14
Accounts payable	(7)	175	31
Accrued liabilities	(268)	365	(116)
Other long-term liabilities (1) (2)	(351)	469	—
Net changes in non-cash working capital	$1,001	$612	$(457)
Relating to:			
Operating activities	$1,346	$299	$(542)
Investing activities	(345)	313	85
	$1,001	$612	$(457)

	2018	2017	2016
Expenditures on exploration and evaluation assets	$282	$159	$29
Net proceeds on sale of exploration and evaluation assets	(16)	(35)	(35)
Net expenditures (proceeds) on exploration and evaluation assets	$266	$124	$(6)
Expenditures on property, plant and equipment	$4,175	$4,574	$4,152
Net proceeds on sale of property, plant and equipment (3)	—	—	(349)
Net expenditures on property, plant and equipment	$4,175	$4,574	$3,803

(1) Included in other long-term liabilities at December 31, 2018 is $118 million of deferred purchase consideration payable over the next five years.

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

(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 years' ended December 31, 2018 and 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
Changes from financing cash flows:			
Repayment of long-term debt, net (1)	(2,831)	—	(2,831)
Changes in foreign exchange and fair value (2)	996	(222)	774
At December 31, 2018	$20,623	$ (361)	$20,262

(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.

22. 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. Midstream activities include the Company’s pipeline operations, an electricity co-generation system and Redwater Partnership.

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.

	North America			North Sea			Offshore Africa		
(millions of Canadian dollars)	2018	2017	2016	2018	2017	2016	2018	2017	2016
Segmented product sales									
Crude oil and NGLs	$7,254	$7,655	$5,933	$753	$666	$478	$628	$579	$532
Natural gas	1,256	1,506	1,276	140	118	92	70	53	71
Total segmented product sales	8,510	9,161	7,209	893	784	570	698	632	603
Less: royalties	(723)	(809)	(524)	(2)	(1)	(1)	(51)	(41)	(26)
Segmented revenue	7,787	8,352	6,685	891	783	569	647	591	577
Segmented expenses									
Production	2,405	2,362	2,186	405	400	403	208	226	200
Transportation, blending and feedstock	2,587	2,291	1,941	22	31	48	2	1	2
Depletion, depreciation and amortization	3,132	3,243	3,465	257	509	458	201	205	262
Asset retirement obligation accretion	87	80	66	29	27	35	9	9	12
Realized risk management (commodity derivatives)	(10)	(45)	6	—	—	—	—	—	—
Gain on acquisition, disposition and revaluation of properties	(277)	(35)	(32)	(139)	—	—	(36)	—	—
Equity loss (gain) from investments	—	—	—	—	—	—	—	—	—
Total segmented expenses	7,924	7,896	7,632	574	967	944	384	441	476
Segmented earnings (loss) before the following	$(137)	$456	$(947)	$317	$(184)	$(375)	$263	$150	$101
Non–segmented expenses									
Administration									
Share-based compensation									
Interest and other financing expense									
Risk management activities (other)									
Foreign exchange loss (gain)									
Loss (gain) from investments									
Total non–segmented expenses									
Earnings (loss) before taxes									
Current income tax expense (recovery)									
Deferred income tax expense (recovery)									
Net earnings (loss)									

Inter-segment elimination and Other includes internal transportation and electricity charges. Production, processing and other purchasing and selling activities that are not included in the above segments are also reported in the segmented information as Inter-segment eliminations and Other. In connection with the adoption of IFRS 15 on January 1, 2018 (see note 2), the Company has reclassified certain comparative figures for product sales, production expense and transportation, blending and feedstock expense for the years ended December 31, 2017 and 2016 in a manner consistent with the presentation adopted for the year ended December 31, 2018.

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		
2018	2017	2016	2018	2017	2016	2018	2017	2016	2018	2017	2016
$11,521	$7,072	$2,657	$102	$102	$114	$410	$448	$682	$20,668	$16,522	$10,396
—	—	—	—	—	—	148	161	167	1,614	1,838	1,606
11,521	7,072	2,657	102	102	114	558	609	849	22,282	18,360	12,002
(479)	(167)	(24)	—	—	—	—	—	—	(1,255)	(1,018)	(575)
11,042	6,905	2,633	102	102	114	558	609	849	21,027	17,342	11,427
3,367	2,600	1,292	21	16	25	58	71	78	6,464	5,675	4,184
1,087	679	80	—	—	—	491	527	751	4,189	3,529	2,822
1,557	1,220	662	14	9	11	—	—	—	5,161	5,186	4,858
61	48	29	—	—	—	—	—	—	186	164	142
—	—	—	—	—	—	—	—	—	(10)	(45)	6
—	(230)	—	—	(114)	(218)	—	—	—	(452)	(379)	(250)
—	—	—	5	(31)	(7)	—	—	—	5	(31)	(7)
6,072	4,317	2,063	40	(120)	(189)	549	598	829	15,543	14,099	11,755
$4,970	$2,588	$570	$62	$222	$303	$9	$11	$20	$5,484	$3,243	$(328)
									325	319	345
									(146)	134	355
									739	631	383
									(124)	80	27
									827	(787)	(55)
									341	(7)	(320)
									1,962	370	735
									3,522	2,873	(1,063)
									374	(164)	(618)
									557	640	(241)
									$2,591	$2,397	$(204)

Capital Expenditures [1]

	2018			2017		
	Net expenditures	Non-cash and fair value changes	Capitalized costs	Net expenditures [2]	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [3]	$ 118	$ (52)	$ 66	$ 160	$ (184)	$ (24)
North Sea	—	—	—	—	—	—
Offshore Africa [4]	(54)	—	(54)	15	—	15
Oil Sands Mining and Upgrading	218	(225)	(7)	142	117	259
	$ 282	$ (277)	$ 5	$ 317	$ (67)	$ 250
Property, plant and equipment						
Exploration and Production						
North America	$ 2,553	$ (362)	$ 2,191	$ 2,815	$ 354	$ 3,169
North Sea	131	(597)	(466)	160	95	255
Offshore Africa	228	(86)	142	89	12	101
	2,912	(1,045)	1,867	3,064	461	3,525
Oil Sands Mining and Upgrading [5]	1,229	(166)	1,063	9,592	5,454	15,046
Midstream [6]	13	—	13	80	114	194
Head office	21	—	21	19	—	19
	$ 4,175	$ (1,211)	$ 2,964	$ 12,755	$ 6,029	$ 18,784

(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) The above noted figures for 2017 exclude the impact of a pre-tax cash gain of $35 million on the disposition of certain exploration and evaluation assets.

(4) The above noted figures for 2018 exclude the impact of a pre-tax cash gain of $16 million on the disposition of certain exploration and evaluation assets.

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

(6) Included in 2017 is 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

	2018	2017
Exploration and Production		
North America	$27,199	$28,705
North Sea	1,699	1,854
Offshore Africa	1,471	1,331
Other	33	29
Oil Sands Mining and Upgrading	39,634	40,559
Midstream	1,413	1,279
Head office	110	110
	$71,559	$73,867

23. REMUNERATION OF DIRECTORS AND SENIOR MANAGEMENT

Remuneration of Non-Management Directors

	2018	2017	2016
Fees earned	$ 2	$ 3	$ 2

Remuneration of Senior Management [1]

	2018	2017	2016
Salary	$ 2	$ 3	$ 3
Common stock option based awards	8	10	9
Annual incentive plans	4	5	5
Long-term incentive plans	15	17	15
	$ 29	$ 35	$ 32

(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.

Canadian Natural Resources Limited
MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEAR ENDED DECEMBER 31, 2018

MANAGEMENT'S DISCUSSION AND ANALYSIS

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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

ADVISORY

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, production expenses, capital expenditures, income tax expenses and other guidance provided throughout this Management’s Discussion and Analysis (“MD&A”) of the financial condition and results of operations of the Company, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the cost and timing of construction and future operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, natural gas liquids ("NGLs") or synthetic crude oil (“SCO”) that the Company may be reliant upon to transport its products to market, development and deployment of technology and technological innovations, the assumption of operations at processing facilities, and the "Outlook" section of this MD&A, particularly in reference to the 2019 guidance provided with respect to budgeted capital expenditures, also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are 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 actual 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 expenditures and production expenses); 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 MD&A could also have 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 applicable 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 the Company'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; adjusted funds flow (previously referred to as funds flow from operations); net capital expenditures; adjusted cash production costs; adjusted depreciation, depletion, and amortization; 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), cash flows from operating activities, and cash flows used in investing activities as determined in accordance with IFRS, as an indication of the Company’s performance. The non-GAAP measure adjusted net earnings (loss) from operations is reconciled to net earnings (loss), as determined in accordance with IFRS, in the “Financial and Operational Highlights" section of this MD&A. Additionally, the non-GAAP measure adjusted funds flow is reconciled to cash flows from operating activities, as determined in accordance with IFRS, in the "Financial and Operational Highlights" section of this MD&A. The non-GAAP measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the "Net Capital Expenditures" section of this MD&A. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the “Operating Highlights – Oil Sands Mining and Upgrading” section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the “Liquidity and Capital Resources” section of this MD&A.

Special Note Regarding Currency, Financial Information, Production and Reserves

This MD&A should be read in conjunction with the audited consolidated financial statements and related notes for the year ended December 31, 2018. It should also be read in conjunction with the Company's MD&A for the three months and year ended December 31, 2018, 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").

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

The following discussion and analysis refers primarily to the Company’s 2018 financial results compared to 2017 and 2016, unless otherwise indicated. In addition, this MD&A details the Company's targeted capital program for 2019. Additional information relating to the Company, including its quarterly MD&A for the three months and year ended December 31, 2018, its Annual Information Form for the year ended December 31, 2018, and its audited consolidated financial statements for the year ended December 31, 2018 is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Detailed guidance on production levels, capital expenditures and production expenses can be found on the Company's website at www.cnrl.com. This MD&A is dated March 6, 2019.

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 expense 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

FINANCIAL AND OPERATIONAL HIGHLIGHTS

($ millions, except per common share amounts)		2018	2017	2016
Product sales		$ 22,282	$ 18,360	$ 12,002
Crude oil and NGLs		$ 20,668	$ 16,522	$ 10,396
Natural gas		$ 1,614	$ 1,838	$ 1,606
Net earnings (loss)		$ 2,591	$ 2,397	$ (204)
Per common share	– basic	$ 2.13	$ 2.04	$ (0.19)
	– diluted	$ 2.12	$ 2.03	$ (0.19)
Adjusted net earnings (loss) from operations (1)		$ 3,263	$ 1,403	$ (669)
Per common share	– basic	$ 2.68	$ 1.19	$ (0.61)
	– diluted	$ 2.67	$ 1.19	$ (0.61)
Cash flows from operating activities		$ 10,121	$ 7,262	$ 3,452
Adjusted funds flow (2)		$ 9,088	$ 7,347	$ 4,293
Per common share	– basic	$ 7.46	$ 6.25	$ 3.90
	– diluted	$ 7.43	$ 6.21	$ 3.89
Dividends declared per common share (3)		$ 1.34	$ 1.10	$ 0.94
Total assets		$ 71,559	$ 73,867	$ 58,648
Total long-term liabilities		$ 34,823	$ 35,953	$ 27,289
Cash flows used in investing activities		$ 4,814	$ 13,102	$ 3,811
Net capital expenditures (4)		$ 4,731	$ 17,129	$ 3,794
Average sales price				
Crude oil and NGLs - Exploration and Production ($/bbl)		$ 46.92	$ 48.57	$ 36.93
Natural gas - Exploration and Production ($/Mcf)		$ 2.61	$ 2.76	$ 2.32
Oil Sands Mining and Upgrading ($/bbl)		$ 68.61	$ 63.98	$ 58.59
Daily production, before royalties (BOE/d)		1,078,813	962,264	805,782
Crude oil and NGLs (bbl/d)		820,778	685,236	523,873
Natural gas (MMcf/d)		1,548	1,662	1,691

(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 the after-tax effects of certain items of a non-operational nature. The Company considers adjusted net earnings (loss) from operations a key measure in evaluating the Company's performance, as it demonstrates the Company’s ability to generate after-tax

operating earnings from its core business areas. The reconciliation “Adjusted Net Earnings (Loss) from Operations, as Reconciled to Net Earnings (Loss)” is presented in this MD&A. Adjusted net earnings (loss) from operations may not be comparable to similar measures presented by other companies.

(2) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment and certain movements in other long-term assets. The Company considers adjusted funds flow 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 “Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities” is presented in this MD&A. Adjusted funds flow may not be comparable to similar measures presented by other companies.

(3) On March 6, 2019, the Board of Directors approved an increase in the quarterly dividend to $0.375 per common share, beginning with the dividend payable on April 1, 2019. 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.

(4) Net capital expenditures is a non-GAAP measure that represents cash flows used in investing activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, investment in other long-term assets, share consideration in business acquisitions (dispositions) and abandonment expenditures. The Company considers net capital expenditures a key measure as it provides an understanding of the Company’s capital spending activities in comparison to the Company's annual capital budget. The reconciliation “Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities” is presented in the "Net Capital Expenditures" section of this MD&A. Net capital expenditures may not be comparable to similar measures presented by other companies.

Principal Documents Exhibits

Adjusted Net Earnings (Loss) from Operations, as Reconciled to Net Earnings (Loss)

($ millions)	2018	2017	2016
Net earnings (loss), as reported	$2,591	$2,397	$(204)
Share-based compensation, net of tax (1)	(146)	134	355
Unrealized risk management (gain) loss, net of tax (2)	(36)	33	21
Unrealized foreign exchange loss (gain), net of tax (3)	706	(821)	(93)
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)	146	—	—
Loss (gain) from investments, net of tax (5) (6)	374	(11)	(299)
Gain on acquisition, disposition and revaluation of properties, net of tax (7)	(372)	(339)	(241)
Derecognition of exploration and evaluation assets, net of tax (8)	—	—	13
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (9)	—	10	(221)
Adjusted net earnings (loss) from operations	$3,263	$1,403	$(669)

(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) the Oil Sands Mining and Upgrading segment.

(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 those amounts 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) During 2018, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

(5) 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 loss (gain) from investments is the Company's pro rata share of the Redwater Partnership's accounting loss (gain).

(6) 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 measured each period with changes in fair value recognized in net earnings (loss).

(7) During 2018, the Company recorded a pre-tax gain of $16 million ($12 million after-tax) on the disposition of a 30% interest in the exploration right in South Africa. Additionally, the Gabonese Republic approved cessation of production from the Company’s Olowi field and associated asset retirement obligations, as well as the terms of termination of the Olowi Production Sharing Contract and the surrender of the permit area back to the Gabonese Republic, resulting in a pre-tax gain on disposition of property of $20 million ($14 million after-tax). The Company also recorded a pre-tax gain of $277 million ($263 million after-tax) related to acquisitions in the North America Exploration and Production segment. Additionally, the Company recorded a pre-tax gain of $120 million ($72 million after-tax) on the acquisition of the remaining interest at Ninian in the North Sea and a pre-tax gain of $19 million ($11 million after-tax) relating to the revaluation of the Company's previously held interest at Ninian. 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.

(8)

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.

(9) 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.

Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities (1)

($ millions)	2018	2017	2016
Cash flows from operating activities	$10,121	$7,262	$3,452
Net change in non-cash working capital	(1,346)	(299)	542
Abandonment expenditures (2)	290	274	267
Other (3)	23	110	32
Adjusted funds flow	$9,088	$7,347	$4,293

(1) Adjusted funds flow was previously referred to as funds flow from operations.
(2) The Company includes abandonment expenditures in "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" in the "Net Capital Expenditures" section of this MD&A.
(3) Includes certain movements in other long-term assets.

Consolidated Net Earnings (Loss) and Adjusted Net Earnings (Loss)

For 2018, the Company reported net earnings of $2,591 million compared with net earnings of $2,397 million for 2017 (2016 – $204 million net loss). Net earnings for 2018 included net after-tax expenses of $672 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 on repayments of long-term debt, the loss (gain) 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 (2017 – $994 million after-tax income; 2016 – $465 million after-tax income). Excluding these items, adjusted net earnings from operations for 2018 were $3,263 million compared with adjusted net earnings of $1,403 million for 2017 (2016 – $669 million adjusted net loss).

The increase in net earnings and adjusted net earnings from operations for 2018 from 2017 was primarily due to:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- higher realized SCO prices in the Oil Sands Mining and Upgrading segment;
- higher realized risk management gains; and
- higher crude oil and NGLs netbacks in the International segments;

partially offset by:

- lower crude oil and NGLs netbacks in the North America Exploration and Production segment;
- higher depletion, depreciation and amortization in the Oil Sands Mining and Upgrading segment;
- lower natural gas netbacks in the North America Exploration and Production segment; and
- lower crude oil and NGLs sales volumes in the Exploration and Production segments.

Net earnings and adjusted net earnings from operations for 2018 as compared to net earnings and adjusted net earnings from operations for 2017 included the impact of a significant decline in crude oil pricing in November and December 2018 as a result of an oversupplied domestic market environment and a lack of takeaway capacity, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system. The WCS heavy differential averaged US$39.36 per bbl for the fourth quarter of 2018 (third quarter of 2018 - US$22.17 per bbl). The SCO price averaged US$37.48 per bbl for the fourth quarter of 2018 (third quarter of 2018 - US$68.44 per bbl).

Following the Government of Alberta's announcement on December 2, 2018 of a mandatory curtailment of crude oil production, the WCS heavy differential index narrowed to US$12.38 per bbl for the first quarter of 2019 and the differential between SCO and WTI benchmark pricing narrowed to US$2.70 per bbl for the first quarter of 2019. Crude oil and natural gas pricing are discussed in detail in the "Business Environment" section of this MD&A.

The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates also contributed to the movements in net earnings (loss) for 2018 from 2017. These items are discussed in detail in the relevant sections of this MD&A.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for 2018 increased to $10,121 million from $7,262 million for 2017 (2016 – $3,452 million). The increase in cash flows from operating activities for 2018 from 2017 was primarily due to the factors noted above relating to the fluctuations in adjusted net earnings (loss) (except for the effect of depletion, depreciation and amortization), as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for 2018 increased to $9,088 million ($7.46 per common share) from $7,347 million for 2017 ($6.25 per common share) (2016 – $4,293 million; $3.90 per common share). The increase in adjusted funds flow for 2018 from 2017 was primarily due to the factors noted above relating to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment and certain movements in other long-term assets.

Product Pricing

In the Company's Exploration and Production activities, the 2018 average sales price per bbl of crude oil and NGLs decreased 3% to average $46.92 per bbl from $48.57 per bbl in 2017 (2016 – $36.93 per bbl), and the 2018 average natural gas price decreased 5% to average $2.61 per Mcf from $2.76 per Mcf in 2017 (2016 – $2.32 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2018 average SCO sales price increased 7% to average $68.61 per bbl from $63.98 per bbl in 2017 (2016 – $58.59 per bbl). Crude oil and NGLs and natural gas pricing are discussed in detail in the "Business Environment" section of this MD&A.

Production Volumes

Total production of crude oil and NGLs before royalties for 2018 increased 20% to average 820,778 bbl/d from 685,236 bbl/d in 2017 (2016 – 523,873 bbl/d). The increase in crude oil and NGLs production from 2017 was primarily due to the impact of Phase 3 production at Horizon and acquisitions completed in 2017, partially offset by the impact of proactive measures taken by the Company to voluntarily curtail crude oil production and reduce drilling in heavy oil.

Total natural gas production before royalties for 2018 decreased 7% to average 1,548 MMcf/d from 1,662 MMcf/d in 2017 (2016 – 1,691 MMcf/d). The decrease in natural gas production from 2017 primarily reflected the impact of shut-in volumes due to low natural gas prices, a failure on a natural gas transmission line in British Columbia (T-South) and a turnaround at the third-party Pine River processing facility beginning on September 15, 2018. Operations at the facility were partially reinstated on December 6, 2018. Subject to regulatory approval, the Company targets to take over operations at the facility in the first half of 2019.

Total crude oil and NGLs and natural gas production volumes before royalties for 2018 increased 12% to average 1,078,813 BOE/d from 962,264 BOE/d in 2017 (2016 – 805,782 BOE/d). Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

Principal Documents Exhibits

SUMMARY OF QUARTERLY FINANCIAL RESULTS

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

($ millions, except per common share amounts)

2018	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales	$22,282	$3,831	$6,327	$6,389	$5,735
Crude oil and NGLs	$20,668	$3,327	$5,967	$6,071	$5,303
Natural gas	$1,614	$504	$360	$318	$432
Net earnings (loss)	$2,591	$(776)	$1,802	$982	$583
Net earnings (loss) per common share					
– basic	$2.13	$(0.64)	$1.48	$0.80	$0.48
– diluted	$2.12	$(0.64)	$1.47	$0.80	$0.47

($ millions, except per common share amounts)

2017	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales	$18,360	$5,516	$4,725	$4,127	$3,992
Crude oil and NGLs	$16,522	$5,098	$4,320	$3,645	$3,459
Natural gas	$1,838	$418	$405	$482	$533
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

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 Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America including the impact of a shortage of takeaway capacity out of the Western Canadian Sedimentary Basin (the "Basin") and the impact of the differential between WTI and Dated Brent ("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 outages 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, production from Horizon Phase 3 as well as the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, voluntarily curtailed production due to low commodity prices in North America, and the impact of the drilling program in the International segments. 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, fluctuating capacity 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 volumes, the impact of seasonal costs that are dependent on weather, the impact of increased carbon tax and energy costs, cost optimizations across all segments, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, the impact of turnarounds and pitstops in the Oil Sands Mining

and Upgrading segment, 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 the second quarter of 2017, and the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment.

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 impact 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 due to statutory tax rate and other legislative changes substantively enacted in the various periods.

Gains on acquisition, disposition and revaluation of properties and gains/losses on investments – Fluctuations due to the recognition of gains on the acquisition of AOSP and other assets, the acquisition, disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity loss (gain) on the Company's interest in the Redwater Partnership.

BUSINESS ENVIRONMENT

(Yearly average)	2018	2017	2016
WTI benchmark price (US$/bbl)	$64.78	$50.93	$43.37
Dated Brent benchmark price (US$/bbl)	$71.12	$54.38	$43.96
WCS heavy differential from WTI (US$/bbl)	$26.29	$11.97	$13.91
SCO price (US$/bbl)	$58.62	$52.20	$43.94
Condensate benchmark price (US$/bbl)	$60.98	$51.65	$42.51
NYMEX benchmark price (US$/MMBtu)	$3.08	$3.11	$2.45
AECO benchmark price (C$/GJ)	$1.45	$2.30	$1.98
US/Canadian dollar average exchange rate (US$)	$0.7717	$0.7701	$0.7548
US/Canadian dollar year end exchange rate (US$)	$0.7328	$0.7988	$0.7448

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 2018, 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 2018, with a high of approximately US$0.81 in February 2018 and a low of approximately US$0.73 in December 2018.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$64.78 per bbl for 2018, an increase of 27% from US$50.93 per bbl for 2017 (2016 – US$43.37 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$71.12 per bbl for 2018, an increase of 31% from US$54.38 per bbl for 2017 (2016 – US$43.96 per bbl).

WTI and Brent pricing for 2018 increased from 2017 primarily due to declines in global crude oil inventories, together with larger than anticipated increases in global demand for crude oil.

The WCS heavy differential averaged US$26.29 per bbl for 2018, an increase of 120% from US$11.97 per bbl for 2017 (2016 – US$13.91 per bbl). The significant widening of the WCS heavy differential reflected a shortage of takeaway capacity out of the Basin, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system. Following the Government of Alberta's announcement on December 2, 2018 of a mandatory curtailment of crude oil

production, the WCS heavy differential index narrowed to US$12.38 per bbl for the first quarter of 2019 compared to US$39.36 per bbl during the fourth quarter of 2018.

The SCO price averaged US$58.62 per bbl for 2018, an increase of 12% from US$52.20 per bbl for 2017 (2016 – US$43.94 per bbl). The increase in SCO pricing for 2018 from 2017 primarily reflected increases in WTI benchmark pricing through the third quarter of 2018, partially offset by decreased pricing in the fourth quarter of 2018 due to a shortage of takeaway capacity out of the Basin, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system. Following the Government of Alberta's announcement on December 2, 2018 of a mandatory curtailment of crude oil production, the differential between SCO and WTI benchmark pricing narrowed to US$2.70 per bbl for the first quarter of 2019 compared to US$21.35 per bbl during the fourth quarter of 2018.

Condensate pricing averaged US$60.98 per bbl for 2018, an increase of 18% from US$51.65 per bbl for 2017 (2016 – US$42.51 per bbl). The increase in condensate pricing for 2018 from 2017 primarily reflected increases in the underlying benchmark pricing.

NYMEX natural gas prices averaged US$3.08 per MMBtu for 2018, comparable with US$3.11 per MMBtu for 2017 (2016 – US$2.45 per MMBtu). AECO natural gas prices averaged $1.45 per GJ for 2018, a decrease of 37% from $2.30 per GJ for 2017 (2016 – $1.98 per GJ).

The decrease in AECO natural gas prices for 2018 compared with 2017 reflected third party pipeline constraints limiting flow of natural gas to export markets as well as increased natural gas production in the Basin.

Principal Documents Exhibits

ANALYSIS OF CHANGES IN PRODUCT SALES

($ millions)	2016	Changes due to Volumes	Prices	Other	2017	Changes due to Volumes	Prices	Other	2018
North America									
Crude oil and NGLs	$5,933	$135	$1,755	$(168)	$7,655	$(188)	$(224)	$11	$7,254
Natural gas	1,276	(20)	250	—	1,506	(105)	(136)	(9)	1,256
	7,209	115	2,005	(168)	9,161	(293)	(360)	2	8,510
North Sea									
Crude oil and NGLs	478	63	130	(5)	666	(69)	155	1	753
Natural gas	92	3	23	—	118	(23)	45	—	140
	570	66	153	(5)	784	(92)	200	1	893
Offshore Africa									
Crude oil and NGLs	532	(70)	103	14	579	(102)	164	(13)	628
Natural gas	71	(22)	4	—	53	10	7	—	70
	603	(92)	107	14	632	(92)	171	(13)	698
Subtotal									
Crude oil and NGLs	6,943	128	1,988	(159)	8,900	(359)	95	(1)	8,635
Natural gas	1,439	(39)	277	—	1,677	(118)	(84)	(9)	1,466
	8,382	89	2,265	(159)	10,577	(477)	11	(10)	10,101
Oil Sands Mining and Upgrading	2,657	3,827	561	27	7,072	3,696	722	31	11,521
Midstream	114	—	—	(12)	102	—	—	—	102
Intersegment eliminations and other (1)	849	—	—	(240)	609	—	—	(51)	558
Total	$12,002	$3,916	$2,826	$(384)	$18,360	$3,219	$733	$(30)	$22,282

(1) Eliminates internal transportation and electricity charges and includes production, processing and other purchasing and selling activities that are not included in the above segments.

Product sales increased 21% to $22,282 million for 2018 from $18,360 million for 2017 (2016 – $12,002 million). The increase was primarily due to higher SCO sales volumes and higher realized SCO sales prices in the Oil Sands Mining and Upgrading segment.

For 2018, 7% of the Company’s crude oil and NGLs and natural gas product sales were generated outside of North America (2017 – 8%; 2016 – 10%). North Sea accounted for 4% of crude oil and NGLs and natural gas product sales for 2018 (2017 – 4%; 2016 – 5%), and Offshore Africa accounted for 3% of crude oil and NGLs and natural gas product sales for 2018 (2017 – 4%; 2016 – 5%).

DAILY PRODUCTION, before royalties

	2018	2017	2016
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	350,961	359,449	350,958
North America – Oil Sands Mining and Upgrading (1)	426,190	282,026	123,265
North Sea	23,965	23,426	23,554
Offshore Africa	19,662	20,335	26,096
	820,778	685,236	523,873
Natural gas (MMcf/d)			
North America	1,490	1,601	1,622
North Sea	32	39	38
Offshore Africa	26	22	31
	1,548	1,662	1,691
Total barrels of oil equivalent (BOE/d)	1,078,813	962,264	805,782
Product mix			
Light and medium crude oil and NGLs	13%	14%	17%
Pelican Lake heavy crude oil	6%	6%	6%
Primary heavy crude oil	8%	10%	13%
Bitumen (thermal oil)	10%	12%	14%
Synthetic crude oil (1)	39%	29%	15%
Natural gas	24%	29%	35%
Percentage of gross revenue (1) (2) (excluding Midstream revenue)			
Crude oil and NGLs	93%	90%	85%
Natural gas	7%	10%	15%

(1) 2018 SCO production before royalties excludes 3,093 bbl/d of SCO consumed internally as diesel (2017 - 651 bbl/d, 2016 - 1,966 bbl/d).

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

DAILY PRODUCTION, net of royalties

	2018	2017	2016
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	303,956	312,297	311,059
North America – Oil Sands Mining and Upgrading	405,731	274,437	122,258
North Sea	23,902	23,382	23,497
Offshore Africa	18,450	19,124	24,995
	752,039	629,240	481,809
Natural gas (MMcf/d)			
North America	1,432	1,528	1,559
North Sea	32	39	38
Offshore Africa	23	20	30
	1,487	1,587	1,627
Total barrels of oil equivalent (BOE/d)	999,857	893,702	752,974

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 2018 production averaged 1,078,813 BOE/d, a 12% increase from 962,264 BOE/d in 2017 (2016 – 805,782 BOE/d).

Total production of crude oil and NGLs for 2018 increased 20% to 820,778 bbl/d from 685,236 bbl/d for 2017 (2016 – 523,873 bbl/d). The increase in crude oil and NGLs production from 2017 was primarily due to the impact of Phase 3 production at Horizon and acquisitions completed in 2017, partially offset by the impact of proactive measures taken by the Company to voluntarily curtail crude oil production and reduce heavy oil drilling. Crude oil and NGLs production for 2018 was above the midpoint of the Company’s previously issued guidance of 812,000 to 822,000 bbl/d.

Natural gas production accounted for 24% of the Company's total production in 2018 on a BOE basis. Natural gas production for 2018 decreased 7% to 1,548 MMcf/d from 1,662 MMcf/d for 2017 (2016 – 1,691 MMcf/d). The decrease in natural gas production from 2017 primarily reflected the impact of shut-in volumes due to low natural gas prices, natural field declines and reduced drilling activity, together with the impact of downtime and restricted capacity at the third-party Pine River processing facility. Subject to regulatory approval, the Company targets to take over operations at the facility in the first half of 2019. Natural gas production for 2018 was within the Company’s previously issued guidance of 1,545 to 1,555 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production for 2018 decreased 2% to average 350,961 bbl/d from 359,449 bbl/d for 2017 (2016 – 350,958 bbl/d). The decrease in production from 2017 primarily reflected the impact of proactive measures taken by the Company to voluntarily curtail crude oil production, together with reduced heavy oil drilling and natural field declines.

Operating performance at Pelican Lake continued to be strong following the acquisition completed in 2017, leading to average production of 63,082 bbl/d in 2018 compared with 51,743 bbl/d in 2017 (2016 – 47,637 bbl/d). The polymer flood on the acquired Pelican assets was restored to 62% of the field.

Overall thermal oil production for 2018 averaged 107,839 bbl/d compared with 120,140 bbl/d for 2017 (2016 – 111,046 bbl/d). Production volumes in 2018 primarily reflected the impact of proactive measures taken by the Company to voluntarily curtail crude oil production.

Natural gas production for 2018 decreased 7% to average 1,490 MMcf/d from 1,601 MMcf/d for 2017 (2016 – 1,622 MMcf/d). The decrease in natural gas production from 2017 primarily reflected the impact of shut-in volumes due to low natural gas prices, natural field declines and reduced drilling activity, together with the impact of downtime and restricted capacity at the third-party Pine River processing facility.

North America – Oil Sands Mining and Upgrading

SCO production for 2018 increased 51% to 426,190 bbl/d from 282,026 bbl/d for 2017 (2016 – 123,265 bbl/d). The increase in SCO production from 2017 primarily reflected high Phase 3 production reliability at Horizon and the acquisition of AOSP.

North Sea

North Sea crude oil production for 2018 increased 2% to 23,965 bbl/d from 23,426 bbl/d for 2017 (2016 – 23,554 bbl/d). The increase in production from 2017 primarily reflected the successful drilling program completed in 2018, partially offset by natural field declines.

Offshore Africa

Offshore Africa crude oil production for 2018 decreased 3% to 19,662 bbl/d from 20,335 bbl/d for 2017 (2016 – 26,096 bbl/d). Production volumes decreased from 2017 primarily due to natural field declines offsetting volumes from new wells drilled at Baobab in the latter half of 2018.

CORPORATE PRODUCTION GUIDANCE FOR 2019

The Company targets production levels in 2019 to average between 782,000 bbl/d and 861,000 bbl/d of crude oil and NGLs and between 1,485 MMcf/d and 1,545 MMcf/d of natural gas. Corporate crude oil and NGLs production guidance for 2019 reflects production curtailments as currently mandated by the Government of Alberta for the first quarter of 2019.

Principal Documents Exhibits

International Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when control of the product passes 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)	2018	2017	2016
North Sea	71,832	—	987,316
Offshore Africa	404,475	121,936	1,126,999
	476,307	121,936	2,114,315

EXPLORATION AND PRODUCTION

Operating Highlights

	2018	2017	2016
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	$46.92	$48.57	$36.93
Transportation	3.08	2.80	2.61
Realized sales price, net of transportation	43.84	45.77	34.32
Royalties	5.08	5.24	3.40
Production expense	15.69	14.89	14.10
Netback	$23.07	$25.64	$16.82
Natural gas ($/Mcf) (1)			
Sales price (2)	$2.61	$2.76	$2.32
Transportation	0.47	0.39	0.33
Realized sales price, net of transportation	2.14	2.37	1.99
Royalties	0.08	0.11	0.09
Production expense	1.36	1.27	1.18
Netback (3)	$0.70	$0.99	$0.72
Barrels of oil equivalent ($/BOE) (1)			
Sales price (2)	$34.62	$35.54	$27.58
Transportation	2.96	2.66	2.44
Realized sales price, net of transportation	31.66	32.88	25.14
Royalties	3.27	3.40	2.21
Production expense	12.71	11.95	11.18
Netback	$15.68	$17.53	$11.75

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

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

(3) Natural gas netbacks exclude netbacks derived from the sale of NGLs. Combining natural gas and NGLs, the netback for 2018 was $1.18/Mcfe (2017 - $1.31/Mcfe, 2016 - $0.89/Mcfe).

Product Prices

	2018	2017	2016
Crude oil and NGLs ($/bbl) (1) (2)			
North America	$41.82	$45.85	$34.31
North Sea	$87.41	$69.43	$55.91
Offshore Africa	$90.95	$67.15	$54.96
Company average	$46.92	$48.57	$36.93
Natural gas ($/Mcf) (1) (2)			
North America	$2.33	$2.58	$2.15
North Sea	$12.08	$8.24	$6.62
Offshore Africa	$7.34	$6.57	$6.13
Company average	$2.61	$2.76	$2.32
Company average ($/BOE) (1) (2)	$34.62	$35.54	$27.58

(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 decreased 3% to average $46.92 per bbl for 2018 from $48.57 per bbl for 2017 (2016 – $36.93 per bbl), primarily due to the significant widening of the WCS heavy differential in the fourth quarter of 2018, partially offset by higher WTI and Brent benchmark pricing.

The Company's realized natural gas price decreased 5% to average $2.61 per Mcf for 2018 from $2.76 per Mcf for 2017 (2016 – $2.32 per Mcf). The decrease in 2018 primarily reflected third party pipeline constraints limiting the flow of natural gas to the export market, together with increased natural gas production in the Basin.

North America - Product Prices

North America realized crude oil prices decreased 9% to average $41.82 per bbl for 2018 from $45.85 per bbl for 2017 (2016 – $34.31 per bbl), primarily due to the widening of the WCS heavy differential, which reflected a shortage of takeaway capacity out of the Basin, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system.

North America realized natural gas prices decreased 10% to average $2.33 per Mcf for 2018 from $2.58 per Mcf for 2017 (2016 – $2.15 per Mcf). The decrease primarily reflected third party pipeline constraints limiting the flow of natural gas to the export market, together with increased natural gas production in the Basin.

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 2018, the Company contributed approximately 175,100 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 Trans Mountain Pipeline Expansion from Edmonton, Alberta to Vancouver, British Columbia. The National Energy Board has provided their recommendation that construction of the pipeline should proceed and the related Federal Government consultations with Indigenous communities are ongoing. Subject to Cabinet's final approval, the project could be issued a revised Certificate of Public Convenience and Necessity this summer with construction re-starting as early as August 2019.

The Company has also entered into a 20 year transportation agreement to ship 175,000 bbl/d of crude oil on the proposed TransCanada Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast. TransCanada is awaiting the completion of a new supplemental environmental review addressing issues raised through litigation in a Montana Federal Court Case. A decision is also expected in April 2019 on the Nebraska Public Service Commission's route approval. Pre-construction activities have started and TransCanada is working to maintain an expected in-service date in 2021.

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

(Yearly average)	2018	2017	2016
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	$52.87	$47.78	$37.72
Pelican Lake heavy crude oil ($/bbl)	$43.30	$48.30	$36.03
Primary heavy crude oil ($/bbl)	$38.98	$46.88	$34.73
Bitumen (thermal oil) ($/bbl)	$33.66	$42.49	$30.47
Natural gas ($/Mcf)	$2.33	$2.58	$2.15

(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 - Product Prices

North Sea realized crude oil prices increased 26% to average $87.41 per bbl for 2018 from $69.43 per bbl for 2017 (2016 – $55.91 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 2018 reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa - Product Prices

Offshore Africa realized crude oil prices increased 35% to average $90.95 per bbl for 2018 from $67.15 per bbl for 2017 (2016 – $54.96 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 2018 reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Royalties

	2018	2017	2016
Crude oil and NGLs ($/bbl) [1]			
North America	$5.36	$5.69	$3.69
North Sea	$0.22	$0.13	$0.13
Offshore Africa	$6.00	$4.13	$2.31
Company average	$5.08	$5.24	$3.40
Natural gas ($/Mcf) [1]			
North America	$0.07	$0.11	$0.08
Offshore Africa	$1.00	$0.76	$0.28
Company average	$0.08	$0.11	$0.09
Company average ($/BOE) [1]	$3.27	$3.40	$2.21

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

North America - Royalties

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 royalty rates for 2018 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalty rates also reflected fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalty rates averaged approximately 14% of product sales for 2018 compared with 13% of product sales for 2017 (2016 – 12%). The increase in royalty rates for 2018 from 2017 was primarily due to higher realized crude oil prices for the majority of 2018, offsetting the impact of lower realized crude oil prices in the fourth quarter of 2018.

Natural gas royalty rates averaged approximately 4% of product sales for 2018 compared with 5% of product sales for 2017 (2016 – 4%). The decrease in royalty rates for 2018 from 2017 was primarily due to lower realized natural gas prices.

Offshore Africa - Royalties

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital expenditures and production expenses, the status of payouts, and the timing of liftings from each field. Royalty rates as a percentage of product sales averaged approximately 7% for 2018 compared with 7% of product sales for 2017 (2016 – 4%). Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

Production Expense

	2018	2017	2016
Crude oil and NGLs ($/bbl) [1]			
North America	$13.48	$12.71	$11.89
North Sea	$39.89	$36.60	$42.47
Offshore Africa	$26.34	$24.07	$18.48
Company average	$15.69	$14.89	$14.10
Natural gas ($/Mcf) [1]			
North America	$1.25	$1.19	$1.12
North Sea	$5.29	$3.37	$3.09
Offshore Africa	$2.76	$2.90	$1.79
Company average	$1.36	$1.27	$1.18
Company average ($/BOE) [1]	$12.71	$11.95	$11.18

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

North America - Production Expense

North America crude oil and NGLs production expense for 2018 increased 6% to $13.48 per bbl from $12.71 per bbl for 2017 (2016 – $11.89 per bbl). The increase in crude oil and NGLs production expense for 2018 from 2017 reflected increased carbon tax and energy costs in 2018 together with increased costs associated with the Company's proactive measures to voluntarily curtail crude oil production, partially offset by the Company's continuous focus on cost control and achieving efficiencies across the entire asset base.

North America natural gas production expense for 2018 increased 5% to $1.25 per Mcf from $1.19 per Mcf for 2017 (2016 – $1.12 per Mcf). The increase in natural gas production expense for 2018 from 2017 primarily reflected the impact of lower volumes on a relatively fixed cost base due to low natural gas prices and a turnaround at the third-party Pine River processing facility. Production expense in 2018 also reflected additional costs associated with the shut-in of production due to low natural gas pricing during 2018, partially offset by the Company's continuous focus on cost control and achieving efficiencies across the entire asset base.

North Sea - Production Expense

North Sea crude oil production expense for 2018 increased 9% to $39.89 per bbl from $36.60 per bbl for 2017 (2016 – $42.47 per bbl). The increase in crude oil production expense for 2018 from 2017 primarily reflected higher carbon tax costs and the strengthening of the UK pound sterling compared to the Canadian dollar.

Offshore Africa - Production Expense

Offshore Africa crude oil production expense related to the Baobab and Espoir fields in Côte d'Ivoire for 2018 was $13.30 per bbl, compared to $12.41 per bbl for 2017. Total Offshore Africa crude oil production expense, including the Olowi field in Gabon, was $26.34 per bbl for 2018, an increase of 9% from $24.07 per bbl for 2017 (2016 – $18.48 per bbl). Total Offshore Africa crude oil production expense for 2018 primarily reflected the timing of liftings from various fields, including the Olowi field in Gabon, that have different cost structures, fluctuating production volumes on a relatively fixed cost base, and planned maintenance activities. Production expense was also impacted by movements in the Canadian dollar.

During 2018, the Gabonese Republic approved cessation of production from the Company’s Olowi field, as well as the terms of termination of the Olowi Production Sharing Contract and the surrender of the permit area back to the Gabonese Republic, including associated asset retirement obligations of $69 million. The transaction resulted in a pre-tax gain on disposition of property of $20 million ($14 million after-tax). In January 2019, the Company completed FPSO demobilization and sail away activities.

Depletion, Depreciation and Amortization

($ millions, except per BOE amounts)	2018	2017	2016
North America	$3,132	$3,243	$3,465
North Sea	257	509	458
Offshore Africa	201	205	262
Expense	$3,590	$3,957	$4,185
$/BOE [(1)]	$15.12	$15.82	$16.79

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

Depletion, depreciation and amortization in 2018 decreased 4% to $15.12 per BOE from $15.82 per BOE for 2017 (2016 – $16.79 per BOE). The decrease in depletion, depreciation and amortization expense per BOE for 2018 from 2017 was primarily due to the impact of additional depletion, depreciation and amortization expense in 2017 related to the abandonment of the Ninian North platform in the North Sea.

Asset Retirement Obligation Accretion

($ millions, except per BOE amounts)	2018	2017	2016
North America	$87	$80	$66
North Sea	29	27	35
Offshore Africa	9	9	12
Expense	$125	$116	$113
$/BOE (1)	$0.53	$0.46	$0.45

(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 per BOE for 2018 increased 15% to $0.53 per BOE from $0.46 per BOE for 2017 (2016 – $0.45 per BOE).

Principal Documents Exhibits

OIL SANDS MINING AND UPGRADING

Operating Highlights

The Company continues to focus on safe, reliable and efficient operations and leveraging its expertise in capturing synergies following the acquisition completed in 2017. Production averaged 426,190 bbl/d during 2018, reflecting strong, reliable operations at Horizon, together with incremental reliability at AOSP. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability of operations, adjusted cash production costs averaged $21.05 per bbl for 2018.

Product Prices, Royalties and Transportation

($/bbl) [(1)]	2018	2017	2016
SCO realized sales price [(2)]	$68.61	$63.98	$58.59
Bitumen value for royalty purposes [(3)]	$40.02	$41.05	$27.57
Bitumen royalties [(4)]	$3.09	$1.64	$0.54
Transportation	$1.61	$1.54	$1.77

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending and feedstock costs.
(3) Calculated as the annual average of the bitumen valuation methodology price.
(4) 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 $68.61 per bbl for 2018, an increase of 7% compared with $63.98 per bbl for 2017 (2016 – $58.59 per bbl). The increase in SCO pricing for 2018 compared to 2017 primarily reflected WTI benchmark pricing.

Cash Production Costs

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 22 to the Company’s audited consolidated financial statements.

($ millions)	2018	2017	2016
Cash production costs	$3,367	$2,600	$1,292
Less: costs incurred during turnaround periods	(109)	(216)	(151)
Adjusted cash production costs	$3,258	$2,384	$1,141
Adjusted cash production costs, excluding natural gas costs	$3,156	$2,239	$1,057
Natural gas costs	102	145	84
Adjusted cash production costs	$3,258	$2,384	$1,141

($/bbl) [(1)]	2018	2017	2016
Adjusted cash production costs, excluding natural gas costs	$ 20.39	$ 21.98	$ 23.36
Natural gas costs	0.66	1.42	1.84
Adjusted cash production costs	$ 21.05	$ 23.40	$ 25.20
Sales (bbl/d)	424,112	279,084	123,652

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

Adjusted cash production costs for 2018 decreased 10% to $21.05 per bbl from $23.40 per bbl for 2017 (2016 – $25.20 per bbl). The decrease in adjusted cash production costs per barrel for 2018 from 2017 primarily reflected the Company's high utilization rates and reliability and the capture of cost synergies between the operations, as well as additional capacity from Phase 3 production at Horizon and the acquisition of AOSP.

Depletion, Depreciation and Amortization

($ millions, except per bbl amounts)	2018	2017	2016
Depletion, depreciation and amortization	$1,557	$1,220	$662
Less: depreciation incurred during turnaround periods	(56)	(213)	(99)
Adjusted depletion, depreciation and amortization	$1,501	$1,007	$563
$/bbl (1)	$9.70	$9.89	$12.43

(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 2018 decreased 2% to $9.70 per bbl from $9.89 per bbl for 2017 (2016 – $12.43 per bbl), primarily due to the impact of AOSP, which has a lower depletion rate.

Asset Retirement Obligation Accretion

($ millions, except per bbl amounts)	2018	2017	2016
Expense	$61	$48	$29
$/bbl (1)	$0.40	$0.47	$0.64

(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 per barrel for 2018 decreased 15% to $0.40 per bbl from $0.47 per bbl for 2017 (2016 – $0.64 per bbl), reflecting higher sales volumes.

MIDSTREAM

($ millions)	2018	2017	2016
Revenue	$102	$102	$114
Less:			
Production expense	21	16	25
Depreciation	14	9	11
Equity loss (gain) from Redwater Partnership	5	(31)	(7)
Gain on disposition and revaluation of properties	—	(114)	(218)
Segment earnings before taxes	$62	$222	$303

The Company's Midstream assets 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 46% 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 asset ownership allows the Company to control transportation costs, earn third party revenue, and manage the marketing of heavy crudes.

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.

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 $9,700 million. The Project is currently in the commissioning phase, with completion targeted for the second quarter of 2019. 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 maintain the agreed debt to equity ratio of 80/20. To December 31, 2018, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $152 million, for a Company total of $591 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, currently consisting of interest and fees, with principal repayments beginning in 2020. The Company is unconditionally obligated to pay this portion of the cost of service toll over the 30 year tolling period. As at December 31, 2018, the Company had recognized $62 million in prepaid service tolls.

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, 2018, Redwater Partnership had borrowings of $2,333 million under its secured $3,500 million syndicated credit facility. During 2018, 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.

CORPORATE AND OTHER

Administration Expense

($ millions, except per BOE amounts)	2018	2017	2016
Expense	$325	$319	$345
$/BOE (1)	$0.83	$0.91	$1.17

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

Administration expense per BOE for 2018 decreased 9% to $0.83 per BOE from $0.91 per BOE for 2017 (2016 – $1.17 per BOE). Administration expense per BOE decreased for 2018 from 2017 primarily due to higher sales volumes.

Share-based Compensation

($ millions)	2018	2017	2016
(Recovery) expense	$(146)	$134	$355

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 an $146 million share-based compensation recovery for the year ended December 31, 2018, 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 the share-based compensation recovery for 2018 was an expense of $8 million related to performance share units granted to certain executive employees (2017 – $5 million; 2016 – $nil). For 2018, the Company recovered $19 million of share-based compensation costs from the Oil Sands Mining and Upgrading segment (2017 – $14 million costs charged, 2016 – $67 million costs charged).

Interest and Other Financing Expense

($ millions, except per BOE amounts and interest rates)	2018	2017	2016
Expense, gross	$808	$713	$616
Less: capitalized interest	69	82	233
Expense, net	$739	$631	$383
$/BOE (1)	$1.88	$1.79	$1.30
Average effective interest rate	3.9%	3.8%	3.9%

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

Gross interest and other financing expense for 2018 increased from 2017 primarily due to the impact of higher average debt levels as a result of acquisitions completed in 2017 and higher interest rates in 2018. Capitalized interest of $69 million for 2018 was primarily related to Kirby North and residual project activities at Horizon.

Net interest and other financing expense for 2018 increased 5% to $1.88 per BOE from $1.79 per BOE for 2017 (2016 – $1.30 per BOE). The increase for 2018 from 2017 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 3.

The Company’s average effective interest rate of 3.9% for 2018 was consistent with 2017 and 2016.

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)	2018	2017	2016
Crude oil and NGLs financial instruments	$(27)	$(32)	$ —
Natural gas financial instruments	5	(7)	—
Foreign currency contracts	(77)	37	8
Realized (gain) loss	$(99)	$(2)	$ 8
Crude oil and NGLs financial instruments	$16	$—	$ —
Natural gas financial instruments	(4)	(6)	6
Foreign currency contracts	(47)	43	19
Unrealized (gain) loss	$(35)	$37	$ 25
Net (gain) loss	$(134)	$35	$ 33

During 2018, net realized risk management gains were related to the settlement of foreign currency contracts and crude oil and NGLs financial instruments. The Company recorded a net unrealized gain of $35 million ($36 million after-tax) on its risk management activities for 2018 (2017 – $37 million unrealized loss, $33 million after-tax; 2016 – $25 million unrealized loss, $21 million after-tax).

Complete details related to outstanding derivative financial instruments at December 31, 2018 are disclosed in note 19 to the Company's audited consolidated financial statements.

Foreign Exchange

($ millions)	2018	2017	2016
Net realized loss	$121	$34	$38
Net unrealized loss (gain)	706	(821)	(93)
Net loss (gain) (1)	$827	$(787)	$(55)

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

The net realized foreign exchange loss for 2018 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes. The net unrealized foreign exchange loss for 2018 was primarily related to the impact of the weakening Canadian dollar with respect to outstanding US dollar debt, partially offset by the reversal of the net unrealized foreign exchange loss on the repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (2018 – unrealized gain of $118 million, 2017 – unrealized loss of $280 million, 2016 – unrealized loss of $295 million). The US/Canadian dollar exchange rate at December 31, 2018 was US$0.7328 (December 31, 2017 – US$0.7988, December 31, 2016 – US$0.7448).

Principal Documents Exhibits

Income Taxes

($ millions, except income tax rates)	2018	2017	2016
North America [1]	$312	$(145)	$(377)
North Sea	28	57	(74)
Offshore Africa	54	45	22
PRT – North Sea	(29)	(132)	(198)
Other taxes	9	11	9
Current income tax expense (recovery)	374	(164)	(618)
Deferred corporate income tax expense (recovery)	540	586	(106)
Deferred PRT expense (recovery) – North Sea	17	54	(135)
Deferred income tax expense (recovery)	557	640	(241)
	931	476	(859)
Income tax rate and other legislative changes	—	(10)	221
	$931	$466	$(638)
Effective income tax rate on adjusted net earnings (loss) from operations [2]	21 %	27 %	45 %

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

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

The effective income tax rate for 2018 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 2018 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.

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 2019, current income tax expense is targeted to range from $300 million to $400 million in Canada and $55 million to $85 million in the North Sea and Offshore Africa.

During 2018, the Company filed Scientific Research and Experimental Development claims of approximately $265 million (2017 – $345 million; 2016 – $549 million) relating to qualifying research and development expenditures for Canadian income tax purposes.

Principal Documents Exhibits

NET CAPITAL EXPENDITURES [1]

($ millions)	2018	2017	2016
Exploration and Evaluation			
Net expenditures (proceeds) [2] [3] [4]	$48	$149	$(6)
Property, Plant and Equipment			
Net property acquisitions [2] [3] [4]	98	1,219	159
Well drilling, completion and equipping	1,446	1,001	712
Production and related facilities	1,262	860	369
Capitalized interest and other [5]	106	91	91
Net expenditures	2,912	3,171	1,331
Total Exploration and Production	2,960	3,320	1,325
Oil Sands Mining and Upgrading			
Project costs [6]	438	821	1,920
Sustaining capital	665	561	379
Turnaround costs	112	155	135
Acquisitions of Exploration and Evaluation assets [2] [4] [7]	218	219	—
Net property acquisitions [2] [4]	—	11,604	—
Capitalized interest and other [5]	14	76	284
Total Oil Sands Mining and Upgrading	1,447	13,436	2,718
Midstream [8]	13	80	(533)
Abandonments [9]	290	274	267
Head office	21	19	17
Total net capital expenditures	$4,731	$17,129	$3,794
By segment			
North America [2] [3] [4]	$2,671	$3,056	$1,048
North Sea [3]	131	160	126
Offshore Africa [3]	158	104	151
Oil Sands Mining and Upgrading [4] [7]	1,447	13,436	2,718
Midstream [8]	13	80	(533)
Abandonments [9]	290	274	267
Head office	21	19	17
Total	$4,731	$17,129	$3,794

(1) Net capital expenditures exclude 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 acquisition and disposition of properties.

(4) During 2017, total purchase consideration for the acquisition of 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.

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

(6) Includes Horizon Phase 2/3 construction costs.

(7) In the fourth quarter of 2018, following integration of the Joslyn oil sands project into the Horizon mine plan and determination of proved crude oil reserves, the exploration and evaluation assets were transferred to property, plant, and equipment.

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

(9)

Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

Principal Documents Exhibits

Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities

($ millions)	2018	2017	2016
Cash flows used in investing activities	$4,814	$13,102	$3,811
Net change in non-cash working capital (1) (2)	(345)	22	5
Investment in other long-term assets	(28)	(87)	(99)
Share consideration in business acquisitions (dispositions)	—	3,818	(190)
Abandonment expenditures (3)	290	274	267
Net capital expenditures	$4,731	$17,129	$3,794

(1) Includes net working capital of $291 million related to the acquisition of AOSP in 2017.
(2) Includes property, plant and equipment of $80 million transferred to inventory in 2016.
(3) The Company excludes abandonment expenditures from "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" in the "Financial and Operational Highlights" section of this MD&A.

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 expenses.

Net capital expenditures for 2018 were $4,731 million compared with $17,129 million for 2017 (2016 – $3,794 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. Net capital expenditures for 2018 included:

- $105 million (US$79 million) of proceeds for the disposal of a 30% interest in the exploration right in South Africa, comprised of exploration and evaluation assets of $89 million, including a recovery of $14 million of past incurred costs in the Offshore Africa segment;
- $218 million of consideration for the acquisition of the Joslyn oil sands project in the Oil Sands Mining and Upgrading segment (comprising $100 million cash on closing with the remaining balance paid equally over the next five years);
- $22 million of cash consideration for the acquisition of Laricina Energy Ltd. in the North America Exploration and Production segment (net of $24 million of cash acquired); and
- $73 million of cash proceeds for the acquisition of the remaining interest at the Ninian field in the North Sea.

2019 Capital Budget

On December 5, 2018, the Company announced its 2019 Capital Budget. The 2019 budget targets a base capital program of $3,700 million, including $3,100 million to maintain current production levels and approximately $600 million directed toward long-term growth projects. The Company maintains capital flexibility in its 2019 budget. Should market access conditions improve, the Company has the capability to adjust 2019 capital spending. Capital expenditures in 2019 are discussed in further detail in the "Outlook" section of this MD&A.

Drilling Activity

(number of wells)	2018	2017	2016
Net successful natural gas wells	18	21	9
Net successful crude oil wells (1)	483	495	174
Dry wells	9	7	7
Stratigraphic test / service wells	615	289	268
Total	1,125	812	458
Success rate (excluding stratigraphic test / service wells)	98%	99%	96%

(1) Includes bitumen wells.

North America

During 2018, the Company targeted 18 net natural gas wells, 6 in Northeast British Columbia and 12 in Northwest Alberta. The Company also targeted 486 net crude oil wells. The majority of these net wells were concentrated in the Company's Northern Plains region where 240 primary heavy crude oil wells, 125 bitumen (thermal oil) wells, 22 Pelican Lake heavy crude oil wells and 7 light crude oil wells were drilled. Another 92 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company's strategic and proactive decisions and its ability to utilize capital flexibility based on its large, balanced and diverse asset base has been reflected in the North America drilling program. During 2018, the Company reallocated capital spending from primary heavy crude oil to light crude oil, with an increase of 32 net wells in light crude oil and a corresponding decrease of 137 net wells in primary heavy crude oil.

North Sea

During 2018, the Company completed four gross production wells and one gross injection well (4.9 on a net basis), successfully completing the 2018 drilling program in the North Sea.

Offshore Africa

During 2018, the Company completed three gross production wells (1.7 on a net basis) at Baobab. The Company is targeting one gross production well and two gross injection wells at Baobab in 2019.

The Company has retained a 20% working interest in Block 11B/12B, off the southern coast of South Africa. In late December, the operator of the exploration right commenced the drilling of an exploratory well. Subsequent to December 31, 2018, the operator announced that drilling results indicate the presence of natural gas condensate. The Company expects the cost of the current exploration well to be fully carried pursuant to two separate farm-out agreements that were completed in 2018.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	2018	2017	2016
Working capital (1)	$(601)	$513	$1,056
Long-term debt (2) (3)	$20,623	$22,458	$16,805
Less: cash and cash equivalents	101	137	17
Long-term debt, net	$20,522	$22,321	$16,788
Share capital	$9,323	$9,109	$4,671
Retained earnings	22,529	22,612	21,526
Accumulated other comprehensive income (loss)	122	(68)	70
Shareholders’ equity	$31,974	$31,653	$26,267
Debt to book capitalization (3) (4)	39%	41%	39%
Debt to market capitalization (3) (5)	34%	29%	26%
After-tax return on average common shareholders’ equity (6)	8%	8%	(1%)
After-tax return on average capital employed (3) (7)	6%	6%	0%

(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 (2018 - $1,141 million, 2017 - $1,877 million, 2016 - $1,812 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.

As at December 31, 2018, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities and access to debt capital markets. Cash flows from operating activities 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 cash flows from operating activities 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 cash flows from operating activities, 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 cash flows from operating activities to facilitate net repayment of bank credit facilities and US dollar debt securities of $3,312 million for 2018, excluding the impact of foreign exchange on debt balances, including:

repayment and cancellation of the $125 million non-revolving credit facility;

repayment and cancellation of $1,200 million of the $3,000 million non-revolving credit facility; and

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

Additionally, the Company utilized available liquidity to settle the deferred payment to Marathon for $481 million, resulting in total net repayments of debt of $2,831 million.

Reviewing the Company's borrowing capacity:

During 2018, the Company extended the $2,425 million revolving syndicated credit facility originally due June 2020 to June 2022. During 2017, the Company extended $2,095 million of the other $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. Each of the $2,425 million revolving facilities is 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 is repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.

During 2018, the Company extended the $2,200 million non-revolving credit facility originally due October 2019 to October 2020. Borrowings under the $2,200 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $2,200 million facility was fully drawn.

During 2018, the Company extended the $750 million non-revolving credit facility originally due in February 2019 to February 2021. Borrowings under the $750 million non-revolving term credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $750 million facility was fully drawn.

Borrowings under the $1,800 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. This facility matures in May 2020 and is subject to annual amortization of 5% of the original balance. As at December 31, 2018, the $1,800 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 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.

Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages. The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at December 31, 2018, the Company was in compliance with this covenant; 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.

As at December 31, 2018, the Company had in place revolving bank credit facilities of $4,976 million of which $4,723 million was available. Additionally, the Company had in place fully drawn term credit facilities of $4,750 million. This excludes certain other dedicated credit facilities supporting letters of credit.

As at December 31, 2018, the Company had total US dollar denominated debt with a carrying amount of $14,611 million (US$10,708 million), before transaction costs and original issue discounts. This included $5,604 million (US$4,108 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$3,058 million). The fixed repayment amount of these hedging instruments is $5,256 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $348 million to $14,263 million as at December 31, 2018.

Net long-term debt was $20,522 million at December 31, 2018, resulting in a debt to book capitalization ratio of 39% (December 31, 2017 – 41%, December 31, 2016 – 39%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities 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, 2018 are discussed in note 11 to the Company's audited 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. As at December 31, 2018, 28,000 bbl/d of currently forecasted crude oil volumes were hedged using WCS differential swaps for January to March 2019 and 8,000 bbl/d were hedged for January to September 2019. Additionally, 10,000 MMbtu/d of currently forecasted natural gas volumes were hedged using AECO basis swaps for January to March 2019, 30,000 GJ/d were hedged using AECO fixed price swaps for January to March 2019 and 10,000 GJ/d were hedged for April to October 2019. Subsequent to December 31, 2018, the Company has hedged an additional 105,000 GJ/d of currently forecasted natural gas volumes using AECO fixed price swaps for April to October 2019. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2018 are discussed in note 19 of the Company's audited consolidated financial statements.

Share Capital

As at December 31, 2018, there were 1,201,886,000 common shares outstanding (December 31, 2017 – 1,222,769,000 common shares) and 46,685,000 stock options outstanding. As at March 5, 2019, the Company had 1,199,849,000 common shares outstanding and 50,413,000 stock options outstanding.

On March 6, 2019, the Board of Directors approved an increase in the quarterly dividend to $0.375 per common share, beginning with the dividend payable on April 1, 2019. 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.

On May 16, 2018, 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 61,454,856 common shares, over a 12-month period commencing May 23, 2018 and ending May 22, 2019. The Company's Normal Course Issuer Bid announced in March 2017 expired on May 22, 2018.

During 2018, the Company purchased for cancellation 30,857,727 common shares at a weighted average price of $41.56 per common share for a total cost of $1,282 million. Retained earnings were reduced by $1,044 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2018, the Company purchased 4,340,000 common shares at a weighted average price of $35.86 per common share for a total cost of $156 million.

COMMITMENTS AND CONTINGENCIES

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, 2018:

($ millions)	2019	2020	2021	2022	2023	Thereafter
Product transportation and pipeline	$692	$664	$620	$516	$381	$ 3,991
North West Redwater Partnership debt service toll (1)	$86	$126	$157	$158	$157	$ 2,858
Offshore equipment operating leases	$94	$73	$75	$8	$—	$ —
Long-term debt (2)	$1,141	$5,996	$1,444	$1,003	$1,365	$ 9,793
Interest and other financing expense (3)	$836	$755	$610	$558	$500	$ 5,327
Office leases	$42	$42	$39	$31	$32	$ 89
Other	$85	$35	$32	$32	$31	$ 424

(1) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, currently consisting of interest and fees, with principal repayments beginning in 2020. Included in the service toll is $1,301 million of interest payable over the 30 year tolling period.

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

(3) Interest and other financing payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2018.

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, 2018, 2017 and 2016, 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, 2018, 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, 2017	374	198	327	1,350	5,264	6,771	229	8,871
Discoveries	—	—	—	—	—	—	—	—
Extensions	12	14	—	171	808	122	9	1,034
Infill Drilling	18	6	—	4	—	470	38	144
	—	—	1	2	—	3	—	4

Improved Recovery								
Acquisitions	11	2	—	—	—	82	4	30
Dispositions	—	(5)	—	—	—	(3)	—	(5)
Economic Factors	5	1	1	—	—	(305)	(4)	(48)
Technical Revisions	14	(2)	(1)	52	175	77	6	257
Production	(35)	(32)	(23)	(39)	(156)	(565)	(15)	(394)
December 31, 2018	399	182	305	1,540	6,091	6,652	267	9,893

Principal Documents Exhibits

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, 2017	544	272	469	2,580	6,063	9,619	335	11,866
Discoveries	—	—	—	—	—	—	—	—
Extensions	16	21	—	230	879	215	14	1,196
Infill Drilling	24	8	—	5	—	861	60	241
Improved Recovery	1	—	3	4	—	4	—	8
Acquisitions	17	3	—	403	—	104	5	445
Dispositions	—	(6)	—	—	—	(5)	—	(7)
Economic Factors	(1)	1	1	—	—	(409)	(5)	(72)
Technical Revisions	9	(15)	(5)	(124)	246	(90)	3	99
Production	(35)	(32)	(23)	(39)	(156)	(565)	(15)	(394)
December 31, 2018	575	252	445	3,059	7,032	9,734	397	13,382

At December 31, 2018, the company gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 8,784 MMbbl, and company gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 11,760 MMbbl. Proved reserves additions and revisions replaced 447% of 2018 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 1,095 MMbbl, and additions to proved plus probable reserves amounted to 1,687 MMbbl. Net positive revisions amounted to 247 MMbbl for proved reserves and 110 MMbbl for proved plus probable reserves, primarily due to technical revisions.

At December 31, 2018, the company gross proved natural gas reserves totaled 6,652 Bcf, and company gross proved plus probable natural gas reserves totaled 9,734 Bcf. Proved reserves additions and revisions replaced 79% of 2018 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 674 Bcf, and additions to proved plus probable reserves amounted to 1,179 Bcf. Net negative revisions amounted to 228 Bcf for proved reserves and 499 Bcf for proved plus probable reserves, primarily due to economic factors.

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 the effect of fluctuating exchange rates on the Company's US dollar denominated debt and revenue from sales 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, including but not limited to restrictions on production;
- 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 seek to 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 seeks to manage 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 seeks to manage 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 designed to reduce the risk of failure or a significant breach of the Company's information technology systems and related data and control systems. 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, 2018.

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. Environmental, social, economic and health considerations are evaluated in new project designs and in operations to improve environmental performance. Processes are employed to avoid, mitigate, minimize or compensate for environmental effects. Working with local communities, the Company considers the values to the people using the land in proximity to operations and adapts projects in recognition of those values.

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, water management and land management to minimize disturbance impacts. The Company's environmental risk management strategies employ an Environmental Management Plan (the "Plan"). As part of risk management, the Company develops, assesses and implements technologies and innovative practices that will improve environmental performance, often through collaborative efforts with industry partners, governments and research institutions. Details of the Plan, along with performance results, are presented to, and reviewed by, the Board of Directors quarterly.

The Plan and the Company's 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 proactive programs that include:

- Environmental planning to assess impacts and implement avoidance and mitigation programs in order to preserve high value biodiversity;
- Continued evaluation of new technologies to reduce environmental impacts, including support for Canada's Oil Sands Innovation Alliance ("COSIA"), Petroleum Technology Alliance Canada ("PTAC") and other research institutions;
- CO_2 reduction programs including carbon capture, CO_2 injection for EOR, CO_2 sequestration in tailings and the Quest carbon capture and storage facility;
- A methane emission reduction program, including solution gas conservation to reduce methane venting, and an equipment retrofit program to reduce methane emissions from pneumatic equipment;
- Optimization of efficiencies at the Company's facilities;
- Water programs to improve efficiency of use and recycle rates as well as to reduce fresh water use;
- An effective reclamation and decommissioning program across the Company's operations, returning sites to their former state. In North America, well abandonment and progressive reclamation of large contiguous areas of land advances biodiversity and establishes functional wildlife habitats;
- Tailings management in Oil Sands Mining to minimize fine tailings and promote reclamation;
- Monitoring programs to assess changes to biodiversity, wildlife and fisheries in order to manage construction and operation effects and to assess reclamation success;
- Participation and support for the Oil Sands Monitoring Program of regional important resources;
- Groundwater monitoring for all thermal in situ and mine operations;
- An active spill prevention and management program; and
- An internal environmental compliance audit and inspection program of operating facilities.

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 5.0% (2017 – 4.7%; 2016 – 5.2%). For 2018, the Company's capital expenditures included $290 million for abandonment expenditures (2017 – $274 million; 2016 – $267 million). The Company's estimated discounted ARO at December 31, 2018 was as follows:

($ millions)	2018	2017
Exploration and Production		
North America	$1,665	$1,840
North Sea	707	755
Offshore Africa	134	245
Oil Sands Mining and Upgrading	1,379	1,486
Midstream	1	1
	$3,886	$4,327

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

As a result of the Company's large, diversified and balanced portfolio and its defined pathway to drive long-term emissions reductions through technology and innovation, the Company is well-positioned to be resilient in a lower carbon economy.

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, 2018, the Alberta government implemented the Carbon Competitiveness Incentive Regulation (CCIR) to replace the Specified Gas Emitters Regulation, for the regulation of GHG emissions from large facilities. The Alberta government has also finalized regulations to reduce methane emissions from the upstream oil and gas sector (consistent with the federal reduction target), with the first regulatory requirements coming into effect January 1, 2020. A previously announced carbon price on combustion emissions from the upstream oil and gas sector is scheduled to begin in 2023. In British Columbia, the provincial government has announced a methane reduction target, comparable to the federal target, and has released final regulations to achieve this target. The Saskatchewan government has also released a regulation to reduce methane emissions from oil production facilities, effective 2020.

In Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually, and those facilities that elect to "opt-in" to the regulation. The carbon price in Alberta is currently $30/tonne for emissions above the regulated limits. Eight of the Company's operated facilities (the facilities at Horizon and AOSP, 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, the Wapiti gas plant, and the Brintnell power generation facility) 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 became subject to a reduction target on January 1, 2019. In British Columbia, carbon tax is currently being assessed at $35/tonne of CO_2e on fuel consumed and gas flared in the province, with the rate increasing to $40/tonne on April 1, 2019. 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 British Columbia government is implementing a program (the CleanBC Plan) to partially mitigate the impact of the carbon tax increases on emission intensive trade exposed (EITE) sectors. The Saskatchewan government has released a regulation that applies to facilities emitting more than 25 kilotonnes of CO_2e annually and will require the North Tangleflags in situ heavy oil facility and the Senlac in situ heavy oil facility to meet reduction targets for GHG emissions effective 2019. The government of Canada has determined that a federal “backstop” carbon pricing system will apply beginning in 2019 in specific provinces and territories within Canada, including the provinces of Saskatchewan and Manitoba in which the Company operates. The federal backstop system will consist of an output-based pricing system for facilities that emit more than 25 kilotonnes CO_2e annually, and a fuel charge that applies to facilities with emissions below this level.

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 offshore 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.

ACCOUNTING POLICIES AND STANDARDS

Changes in Accounting Policies

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.

The Company adopted IFRS 15 on January 1, 2018 using the retrospective with cumulative effect method. There were no changes to reported net earnings (loss) or retained earnings as a result of adopting IFRS 15. Under the standard, the Company is required to provide additional disclosure of disaggregated revenue by major product type. In connection with adoption of the standard, the Company has reclassified certain comparative amounts in a manner consistent with the presentation adopted for the year ended December 31, 2018. For details refer to note 2 of the Company’s audited consolidated financial statements as at December 31, 2018.

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. Applying this expedient had no impact to the revenue recognized under the previous revenue accounting standard as all performance obligations had been met and the consideration had been determined.

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

Accounting Standards Issued but Not Yet Applied

In October 2018, the IASB issued amendments to IFRS 3 "Definition of a Business" that narrowed and clarified the definition of a business. The amendments also permit a simplified assessment of whether an acquired set of activities and assets is a group of assets rather than a business. The amendments are effective January 1, 2020 with earlier adoption permitted. The amendments apply to business combinations after the date of adoption. The Company is assessing the impact of these amendments on its consolidated financial statements.

In October 2018, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" and IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors". The amendments make minor changes to the definition of the term "material" and align the definition across all IFRS Standards. Materiality is used in making judgments related to the preparation of financial statements. The amendments are effective January 1, 2020 with earlier adoption permitted. The Company is assessing the impact of these amendments on its consolidated financial statements.

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 assets 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 has determined that these amendments have no significant impact 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 has determined that this interpretation has no significant impact on its consolidated financial statements.

IFRS 16 "Leases"

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 and requires balance sheet recognition for all leases. Certain short-term (less than 12 months) and low-value leases (as defined in the standard) are exempt from the requirements, and may continue to be treated as an expense. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are exempt from the standard.

The Company will adopt IFRS 16 on January 1, 2019 using the retrospective with cumulative effect method with no impact to opening retained earnings at the date of adoption. In accordance with the transitional provisions in the standard, balances reported in the comparative periods will not be restated.

On initial adoption, the Company intends to use the following practical expedients under the standard. Certain expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- leases with a remaining lease term of less than twelve months as at January 1, 2019 will be treated as short- term leases; and
- exclusion of indirect costs for the measurement of lease assets at the date of initial application.

The Company does not intend to apply any practical expedients pertaining to grandfathering of leases assessed under the previous standard.

On adoption of IFRS 16, the Company will recognize lease assets and liabilities at the present value of the remaining lease payments, discounted using the Company’s applicable borrowing rate on January 1, 2019. The Company expects to report additional lease assets and corresponding liabilities of between $1.5 billion and $1.6 billion. The Company continues to finalize its accounting for leases in accordance with IFRS 16, and the above estimates are subject to change based on finalization of the Company's review of its lease arrangements.

In the statement of earnings, depletion, depreciation and amortization expense and interest expense will increase, with corresponding decreases in production, transportation and administration expenses. The Company does not expect to report a material impact on net earnings. Under the new standard, the Company will report cash outflows for repayment of the principal portion of the lease liability as cash flows from financing activities. The interest portion of the lease payments will continue to be classified as cash flows from operating activities.

Where the Company, acting as the operator, signs a lease on behalf of a joint operation and assumes the legal liability for that lease, the Company will recognize 100% of the related lease asset and lease liability. As the Company recovers its joint operation partners' share of the costs of the lease contract, these recoveries will be recognized in the consolidated statements of earnings.

The Company continues to finalize its evaluation of its contracts that are potentially leases under IFRS 16, as well as implementing changes to policies, internal controls, information systems, and business accounting processes.

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, 2018.

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 5.0%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

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.

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, 2018, 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, including the President and the Chief Financial Officer and Senior Vice-President, Finance, also evaluated the effectiveness of internal control over financial reporting as at December 31, 2018, 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 2018 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 2019 are currently targeted to be as follows:

($ millions)	2019
Exploration and Production	
North America natural gas and NGLs	$365
North America crude oil	775
International crude oil	460
Thermal In Situ Oil Sands	545
Net acquisitions, midstream and other	30
Total Exploration and Production	$2,175
Oil Sands Mining and Upgrading	
Strategic, project development, environment and technology	505
Sustaining capital	780
Turnarounds, reclamation and other	240
Total Oil Sands Mining and Upgrading	$1,525
Total Capital Expenditures	$3,700

Principal Documents Exhibits

OTHER

Sensitivity Analysis

The following table is indicative of the annualized sensitivities of cash flows from operating activities 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 2018, excluding mark-to-market gains (losses) on risk management activities and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flows from Operating Activities ($ millions)	Cash flows from Operating Activities (per common share, basic)	Net earnings (loss) ($ millions)	Net earnings (loss) (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl				
Excluding financial derivatives	$ 279	$ 0.23	$ 279	$ 0.23
Including financial derivatives	$ 274	$ 0.22	$ 274	$ 0.22
Natural gas – AECO C$0.10/Mcf1)				
Excluding financial derivatives	$ 26	$ 0.02	$ 26	$ 0.02
Including financial derivatives	$ 25	$ 0.02	$ 25	$ 0.02
Volume changes				
Crude oil – 10,000 bbl/d	$ 126	$ 0.10	$ 99	$ 0.08
Natural gas – 10 MMcf/d	$ 4	$ —	$ —	$ —
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 157 - 163	$ 0.13	$ 38	$ 0.03
Interest rate change – 1%	$ 37	$ 0.03	$ 37	$ 0.03

(1) For details of financial instruments in place, refer to note 19 to the Company’s audited consolidated financial statements as at December 31, 2018.

Daily Production by Segment, Before Royalties

	Q1	Q2	Q3	Q4	2018	2017	2016
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	357,460	343,538	359,856	343,054	350,961	359,449	350,958
North America – Oil Sands Mining and Upgrading	456,076	407,704	394,382	447,048	426,190	282,026	123,265
North Sea	21,584	24,456	28,702	21,071	23,965	23,426	23,554
Offshore Africa	19,438	18,201	18,802	22,185	19,662	20,335	26,096
Total	854,558	793,899	801,742	833,358	820,778	685,236	523,873
Natural gas (MMcf/d)							
North America	1,547	1,485	1,489	1,441	1,490	1,601	1,622
North Sea	37	30	38	22	32	39	38
Offshore Africa	30	24	26	25	26	22	31
Total	1,614	1,539	1,553	1,488	1,548	1,662	1,691
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	615,228	590,963	608,063	583,242	599,310	626,230	621,239
North America – Oil Sands Mining and Upgrading	456,076	407,704	394,382	447,048	426,190	282,026	123,265
North Sea	27,740	29,485	35,076	24,727	29,264	29,989	29,913
Offshore Africa	24,502	22,224	23,108	26,351	24,049	24,019	31,365
Total	1,123,546	1,050,376	1,060,629	1,081,368	1,078,813	962,264	805,782

Per Unit Results – Exploration and Production

	Q1	Q2	Q3	Q4	2018	2017	2016
Crude oil and NGLs ($/bbl) (1)							
Sales price (2)	$43.06	$61.14	$57.89	$25.95	$46.92	$48.57	$36.93
Transportation	3.10	3.30	3.00	2.94	3.08	2.80	2.61
Realized sales price, net of transportation	39.96	57.84	54.89	23.01	43.84	45.77	34.32
Royalties	4.87	7.56	7.08	0.92	5.08	5.24	3.40
Production expense	15.70	15.64	14.47	16.93	15.69	14.89	14.10
Netback	$19.39	$34.64	$33.34	$5.16	$23.07	$25.64	$16.82
Natural gas ($/Mcf) (1)							
Sales price (2)	$2.74	$1.95	$2.32	$3.46	$2.61	$2.76	$2.32
Transportation	0.51	0.51	0.42	0.42	0.47	0.39	0.33
Realized sales price, net of transportation	2.23	1.44	1.90	3.04	2.14	2.37	1.99
Royalties	0.10	0.08	0.05	0.10	0.08	0.11	0.09
Production expense	1.41	1.39	1.33	1.32	1.36	1.27	1.18
Netback (3)	$0.72	$(0.03)	$0.52	$1.62	$0.70	$0.99	$0.72
Barrels of oil equivalent ($/BOE) (1)							
Sales price (2)	$32.02	$41.63	$40.77	$24.04	$34.62	$35.54	$27.58
Transportation	3.05	3.20	2.83	2.77	2.96	2.66	2.44
Realized sales price, net of transportation	28.97	38.43	37.94	21.27	31.66	32.88	25.14
Royalties	3.10	4.75	4.44	0.80	3.27	3.40	2.21
Production expense	12.68	12.75	11.91	13.51	12.71	11.95	11.18
Netback	$13.19	$20.93	$21.59	$6.96	$15.68	$17.53	$11.75

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

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

(3) Natural gas netbacks exclude netbacks derived from the sale of NGLs. Combining natural gas and NGLs, the netback for the three months ended December 31, 2018 was $1.84/Mcfe (September 30, 2018 – $1.05/Mcfe, June 30, 2018 – $0.60/Mcfe, March 31, 2018 – $1.19/Mcfe; year ended December 31, 2018 – $1.18/Mcfe, December 31, 2017 – $1.31/Mcfe, December 31, 2016 – $0.89/Mcfe).

Per Unit Results – Oil Sands Mining and Upgrading

	Q1	Q2	Q3	Q4	2018	2017	2016
Crude oil and NGLs ($/bbl)							
SCO sales price	$71.61	$80.17	$81.69	$42.73	$68.61	$63.98	$58.59
Bitumen royalties (1)	1.98	4.25	4.31	2.03	3.09	1.64	0.54
Transportation	1.54	1.63	1.73	1.56	1.61	1.54	1.77
Adjusted cash production costs (2)	21.37	22.94	19.95	19.97	21.05	23.40	25.20
Netback	$46.72	$51.35	$55.70	$19.17	$42.86	$37.40	$31.08

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

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

Trading and Share Statistics

	Q1	Q2	Q3	Q4	2018	2017
TSX – C$						
Trading volume (thousands)	174,140	198,092	165,227	268,795	806,254	588,422
Share Price ($/share)						
High	$ 46.77	$ 48.73	$ 49.08	$ 43.31	$ 49.08	$ 47.00
Low	$ 36.88	$ 39.15	$ 40.71	$ 30.11	$ 30.11	$ 35.90
Close	$ 40.50	$ 47.45	$ 42.20	$ 32.94	$ 32.94	$ 44.92
Market capitalization as at December 31 ($ millions)					$ 39,590	$ 54,927
Shares outstanding (thousands)					1,201,886	1,222,769
NYSE – US$						
Trading volume (thousands)	153,374	234,303	154,675	254,619	796,971	608,008
Share Price ($/share)						
High	$ 37.63	$ 38.19	$ 37.41	$ 33.86	$ 38.19	$ 36.78
Low	$ 29.21	$ 30.26	$ 31.29	$ 21.85	$ 21.85	$ 27.53
Close	$ 31.47	$ 36.07	$ 32.66	$ 24.13	$ 24.13	$ 35.72
Market capitalization as at December 31 ($ millions)					$ 29,002	$ 43,677
Shares outstanding (thousands)					1,201,886	1,222,769

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, 2018, 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, 2018, 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, 2018, 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, 2018, 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, 2018 and December 31, 2017, 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 $2,597,000 for 2018 and were $2,960,000 for 2017.

Audit-Related Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ended December 31, 2018 and December 31, 2017, for audit-related services by PwC including pension assets, Crown Royalty Statements and in respect of the AOSP acquisition, were $425,000 for 2018 and were $574,000 for 2017. 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, 2018 and December 31, 2017, for professional services rendered by PwC for tax services related to expatriate personal tax compliance and other corporate tax return matters were $443,000 for 2018 and were $470,000 for 2017. 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, 2018 and December 31, 2017 for other services were $30,000 for 2018 and were $52,000 for 2017, 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, 2018:

($ millions)	2019	2020	2021	2022	2023	Thereafter
Product transportation and pipeline	$692	$664	$620	$516	$381	$ 3,991
North West Redwater Partnership debt service toll [1]	$86	$126	$157	$158	$157	$ 2,858
Offshore equipment operating leases	$94	$73	$75	$8	$—	$ —
Long-term debt [2]	$1,141	$5,996	$1,444	$1,003	$1,365	$ 9,793
Interest and other financing expense [3]	$836	$755	$610	$558	$500	$ 5,327
Office leases	$42	$42	$39	$31	$32	$ 89
Other	$85	$35	$32	$32	$31	$ 424

(1) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, currently consisting of interest and fees, with principal repayments beginning in 2020. Included in the service toll is $1,301 million of interest payable over the 30 year tolling period.

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

(3) Interest and other financing payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2018.

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

Concurrently with the filing of this Form 40-F, Canadian Natural is filing an amendment to its previously filed Form F-X with the SEC to update the address of its agent for service of process.

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 27th day of March, 2019.

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 (Unaudited) for the fiscal year ended December 31, 2018.
101	Interactive data files with respect to the consolidated financial statements for the fiscal year ended December 31, 2018.