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, 2019 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:	**Trading Symbol(s):**	**Name of each exchange on which registered:**
Common Shares, no par value	CNQ	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act: 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.
1,186,857,000 Common Shares outstanding as of December 31, 2019

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

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 Statement on Form F-10 (File No. 333-232692) 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 18, 2020 the reported Bank of Canada daily average exchange rate for one Canadian dollar was US$0.6898. On March 18, 2020 the reported Bank of Canada daily average exchange rate for one U.S. dollar was C$1.4496.

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, 2019.

B. Audited Annual Financial Statements

Canadian Natural's audited consolidated financial statements for the years ended December 31, 2019 and 2018, 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, 2019.

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, 2019, see Exhibit 99.1 to this Annual Report on Form 40-F.



ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2019

March 27, 2020

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Definitions and Abbreviations

ADR	abandonment, decommissioning and reclamation costs
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 wells	gross wells multiplied by the percentage working interest therein owned by the Company
NYSE	New York Stock Exchange
OPEC	Organization of Petroleum Exporting Countries
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

Advisory

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”, “continue”, “could”, “intend”, “may”, “potential”, “predict”, “should”, “will”, “objective”, “project”, “forecast”, “goal”, “guidance”, “outlook”, “effort”, “seeks”, “schedule”, “proposed”, "aspiration" 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, without limitation, those in relation to the Company's assets at Horizon, AOSP, Primrose, Pelican Lake, Kirby and Jackfish, the timing 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 "2020 Activity" section of this AIF with respect to budgeted capital expenditures for 2020, 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 earlier 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 (including as a result of demand and supply effects resulting from the COVID-19 virus pandemic and the actions of OPEC and non-OPEC countries) which will, among other things, impact the demand for and market prices of the Company’s products; volatility of and assumptions regarding crude oil, natural gas and NGLs 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 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, maintain and operate 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 (including production curtailments mandated by the government of Alberta); 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 Consolidated Financial Statements and the Company's MD&A for the most recently completed fiscal year ended December 31, 2019, 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, 2019, 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, 2019 and a preparation date of February 3, 2020. 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 and prepared 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 99 to 106 which is incorporated herein by reference.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

This AIF includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings from operations; adjusted funds flow (previously referred to as funds flow from operations); net capital expenditures; and free cash flow. 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, 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 from operations is reconciled to net earnings, as determined in accordance with IFRS in the “Financial and Operational Highlights" section of the MD&A for the year ended December 31, 2019. 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 for the year ended December 31, 2019. 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 for the year ended December 31, 2019. 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.

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 (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

The Company, as the managing partner, CNR (ECHO) Resources Inc. and Canadian Natural Resources 2005 Partnership are the partners of Canadian Natural Resources, a general partnership. The Company, 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. The Company, as the managing partner, and CNR (ECHO) Resources Inc. are the partners of Canadian Natural Resources 2005 Partnership, a general partnership.

In the ordinary course of business, the Company restructures its subsidiaries and partnerships to maintain efficient operations. The consolidated financial statements of the Company 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

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.

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.

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. The government of Alberta modified its curtailment program effective November 8, 2019 to exempt new wells drilled for conventional oil (any oil produced outside of the oil sands designated areas and formations) from the production limits imposed as part of its curtailment program. In addition, effective December 2019, operators were permitted to apply on a monthly basis to increase oil production if the additional production was to be moved by new incremental rail capacity.

On June 27, 2019, the Company completed its acquisition of substantially all of the assets of Devon Canada Corporation ("Devon") for a total cash purchase consideration of $3,412 million, subject to final closing adjustments. The acquisition consisted of 100% operated thermal in situ production and approximately 95% operated conventional primary heavy crude oil production, both adjacent to existing Company assets, together with 1.5 million acres of land of which 1 million

acres is undeveloped. To finance the acquisition, the Company entered into a three year $3,250 million committed term credit facility, which was fully drawn on the closing of the Devon acquisition.

In addition to the Devon financing, in 2019 the Company made a number of adjustments to its debt financing program. This included repayment and cancellation of the remaining balance of the $1,800 million non-revolving term credit facility originally scheduled to mature in May 2020. The Company increased its $2,200 million non-revolving term credit facility to $2,650 million and extended the due date from October 2020 to February 2023. The $2,425 million revolving syndicated credit facility, previously due June 2021, was extended to June 2023. The Company had previously extended $330 million of this $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The Company repaid $500 million of 3.05% notes and $500 million of 2.60% notes in the second and fourth quarter of 2019 respectively. In the third quarter, the Company filed base shelf prospectuses that allow for the offer of up to $3,000 million of medium term notes in Canada and US$3,000 million of debt securities in the United States, both of which expire in August 2021, replacing the Company's previously filed base shelf prospectuses that would have expired in August 2019.

In the second quarter of 2019, the Company completed commissioning of the central processing facility at Kirby North and commenced reservoir steaming. The Company targets to ramp-up production at Kirby North to its overall capacity of 40,000 bbl/d in the third quarter of 2020.

2020

The government of Alberta announced that the mandatory curtailment measures of crude oil and bitumen production initially imposed in 2018 will be extended to December 31, 2020 with possible early termination.

The Company anticipates that worsening economic conditions resulting from a drop in global oil demand triggered by the spread of the COVID-19 virus, combined with a breakdown in negotiations between OPEC and non-OPEC countries in relation to output cuts intended to stem the drop in crude oil prices and the volatility in prices, may continue until an agreement is reached between OPEC and non-OPEC countries and global oil demand recovers from COVID-19 virus impacts.

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. The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value on a per common share basis through the economic and sustainable 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 in a sustainable and responsible way, maintaining a commitment to environmental stewardship and safety excellence.

The Company has a full complement of management, technical and support staff to pursue these objectives. As of December 31, 2019, the Company had the following full time equivalent permanent employees:

North America, Exploration and Production	4,857
North America, Oil Sands Mining and Upgrading	4,979
North Sea and Offshore Africa	344
Total Company	10,180

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 36% of 2019 production. Natural gas, primarily produced in Alberta, British Columbia and Saskatchewan, accounted for 23% of 2019 production. Light and medium crude oil and NGLs represented 13% of 2019 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 15% of 2019 production, primary heavy crude oil which accounted for 8% of 2019 production, and Pelican Lake heavy crude oil, which accounted for 5% of 2019 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.

As part of the Company's ongoing focus on technology and innovation and the reduction of its environmental footprint, the Company has previously implemented and continues to undertake projects such as: carbon capture, sequestration, storage and utilization projects, including reduction and capture of methane; CO2 capture from hydrogen plants; and research into the production of biofuel from algae. In addition, the Company installs renewable energy sources at remote locations, where appropriate.

The Company has 20 year transportation agreements to ship 94,000 bbl/d of crude oil on the proposed Trans Mountain Pipeline Expansion. The Canadian Energy Regulator (formerly the National Energy Board) has provided its recommendation that construction of the pipeline should proceed and the federal cabinet approved the project on June 18, 2019. On February 4, 2020, an appeal from Indigenous groups to the Federal Court of Appeal was dismissed. Pipeline construction, which had commenced, was permitted to continue subject to the outcome of the appeal to the Supreme Court of Canada. Leave to appeal to the Supreme Court of Canada was refused on March 5, 2020.

The Company also has 20 year transportation agreements to ship 200,000 bbl/d of crude oil on the proposed TC Energy Keystone XL Pipeline. On August 23, 2019, the Nebraska Supreme Court ruled that the Nebraska Public Service Commission's route approval was valid. The proponent is awaiting the decision from the Montana Federal Court case filed by various environmental groups challenging the Presidential Permit granted in 2019. Pre-construction activities have commenced and the proponent expects the construction program to be approximately 2 years once construction has commenced.

A. ENVIRONMENTAL MATTERS

Environmental Management Approach

The Company has a Corporate Statement on Environmental Management which affirms that environmental stewardship is a fundamental value of the Company. This commitment ensures the Company, as well as its employees and contractors, carry out all business activities in compliance with applicable regional, national and international regulations and industry standards. The Company's oil sands mining and the UK divisions also conduct operations in accordance with Environmental Management Systems that are audited by independent third parties. As part of the Company's corporate governance mandate, the Company's environmental specialists track performance to numerous environmental performance indicators in its domestic and international operations, review the operations of the Company's world-wide interests, and regularly report 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 each of the regions where the Company operates. The Company's associated environmental risk management strategy incorporates 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 undertaken 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 biodiversity, air quality and emissions, and ground and surface water; 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.

Canada

As a part of its Plan, the Company has implemented a number of programs to reduce its environmental footprint including: 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; mitigation of the Company's climate change impacts through implementation of various emissions reduction programs and carbon capture projects (including CO_2 injection for EOR, CO_2 sequestration in tailings and the Quest carbon capture and storage facility); a methane emissions reduction program, including solution gas conservation to reduce methane venting and an equipment retrofit program to reduce emissions from pneumatic equipment; and optimization of efficiencies at the Company's facilities.

The Company continues to invest in people, proven and new technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner. The Company has an aspiration of net zero emissions in its oil sands and thermal operations with an integrated GHG emissions reduction strategy which includes: integrating emissions reduction into project planning and operations; leveraging technology to create value and enhance performance; investing in research and development including collaboration with industry, entrepreneurs, academia and governments; focusing on continuous improvement to drive long-term emissions reduction; leading in carbon capture, sequestration and storage; engaging in policy and regulatory development (including trading capacity and offsetting emissions); and reviewing and developing new business opportunities and trends that present further opportunities to reduce the Company's environmental footprint. In Canada, the Company participates in both federal and provincially regulated climate and GHG emissions reporting programs and continues to quantify annual GHG emissions for internal reporting purposes to drive continuous improvement and reduction in GHG emissions intensity. In 2019, the Company's direct emissions from its Alberta oil sands in situ and mining operations were reviewed and verified by an independent professional engineering firm. The Company, through the Canadian Association of Petroleum Producers ("CAPP"), is working with Canadian legislators and regulators as they develop and implement new GHG emissions laws and regulations to support emissions reductions and properly reflect a balanced approach to sustainable development.

Air quality programs are an essential part of the Company's environmental work plan and are operated within all industry and regulatory standards and guidelines. Internally, the Company continues to enhance its 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.

The Company also continues to implement flaring, venting and solution gas conservation programs, which influence and direct its future plans for new projects and facilities. In 2019, the Company completed approximately 443 solution gas conservation projects in its primary heavy crude oil operations, resulting in a reduction of approximately 2.3 million tonnes/year of CO_2e. Over the past five years, the Company has spent over $42 million in its primary heavy crude oil and in situ oil sands operations to conserve the equivalent of over 14.7 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. In 2019, the Company completed 1,680 pneumatic retrofits resulting in reductions of approximately 168,000 tonnes/year of CO_2e. 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 has water programs to improve the efficiency of use and recycle rates as well as reduce fresh water use. The Company has also established operating standards in the following areas: exercising care with respect to all waste produced through effective waste management plans and using water-based, environmentally-friendly drilling muds whenever possible. The Company has also adopted the Hydraulic Fracturing Operating Practices that were developed by CAPP.

The Company has effective programs for well abandonment and decommissioning which allows for the progressive reclamation of large contiguous areas of land to return sites to their former state, the enhancement of biodiversity and the establishment of functional wildlife habitats. The Company continued its environmental liability reduction program with the abandonment of 2,035 inactive wells, and has initiated reclamation at many of these sites with the eventual goal of reclamation certification. In 2019, the Company received 893 reclamation certificates representing 3,118 hectares of land. Further, decommissioning of inactive facilities and cleanup of active facilities was conducted to address environmental liabilities at operating sites. Additionally, the Company has comprehensive programs in place for: tailings management in its oil sands mining operations to minimize fine tailings and promote reclamation; monitoring programs to assess changes to biodiversity, wildlife and fisheries in order to manage construction and operational 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 management system for conformance audit and inspection programs of operating facilities.

International

As part of its Plan, the Company has also implemented environmental programs for its international operations. 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. In addition, decommissioning activities at Murchison platform are targeted to be substantially complete in 2020; offshore decommissioning activities at Ninian North platform are targeted to be substantially complete in 2021 and decommissioning activities at Gabon are substantially complete.

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 that 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 primary 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 produced 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. As a result, Alberta currently has a parallel royalty regime system with the previous Alberta Royalty Framework (``ARF``) continuing to apply until December 31, 2026 to wells drilled prior to January 1, 2017 and the MRF applying to wells drilled on or after January 1, 2017. Under the MRF, conventional royalty rates will range from 5% to 36% for natural gas and NGLs and 5% to 40% for crude oil.

The Company was subject to federal and provincial income taxes in Canada at a combined rate of approximately 26.5% in 2019. The government of Alberta has enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022.

- **Federal Carbon Compliance Costs**

Governments in jurisdictions where the Company operates have developed or are developing GHG regulations as part of their national and international climate change commitments. The Company uses existing GHG regulations to determine the impact of compliance costs on current and future projects. The Company monitors the development of GHG regulations on an ongoing basis in the jurisdictions in which it operates to assess the impact of future regulatory developments on the Company's operations and planned projects. 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.

- **Provincial Carbon Compliance Cost**

Carbon pricing regulatory systems in all provinces are subject to annual review by the federal government to assess the adequacy of the provincial systems against the federal Greenhouse Gas Pollution Pricing Act. Such future reviews may affect the carbon price and/or the stringency of provincial systems.

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. In 2019, nine of the Company’s operated facilities (Horizon, AOSP, Primrose/Wolf Lake, Kirby South, Jackfish, Peace River, Hays, Wapiti and the Brintnell power generation facility) were subject to compliance under the regulation. Effective January 1, 2020, the CCIR was replaced with the Technology Innovation and Emissions Reduction Regulation ("TIER"). The coverage of TIER has expanded to include all of the Company’s assets in Alberta (as an alternative to the federal fuel charge). The carbon price in Alberta is currently $30/tonne for emissions above the TIER regulated limits, and the Alberta government has announced its intention to increase the price to $40/tonne in 2021 and $50/tonne in 2022, in alignment with the federal carbon pricing schedule. Facilities with emissions in previous years above 100,000 tonnes of CO_2e/ year, or that have voluntarily opted into TIER are required to comply with 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 $40/tonne of CO_2e on fuel consumed and gas flared in the province, with the rate increasing to $45/tonne on April 1, 2020. 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 emissions intensive trade exposed (EITE) sectors.

As part of its Prairie Resilience Plan, the Saskatchewan government has released a regulation (“The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations”) that applies to facilities emitting more than 25 kilotonnes of CO_2e annually and requires 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. This regulation also enables facilities below the threshold to aggregate and opt into the Saskatchewan regulatory system as an alternative to the federal fuel charge.

In Manitoba, the federal output-based pricing system applies to facilities with emissions greater than or equal to 10 kilotonnes CO_2e annually, and the federal fuel charge applies to facilities with emissions of less than 10 kilotonnes CO_2e annually.

- **Federal and Provincial Methane Emissions Reduction Regulations**:

The federal government’s methane regulation came into effect on January 1, 2020 and applies nationally unless provinces reach equivalency agreements with the federal government, in which case the federal regulation would not be in effect for those jurisdictions. 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. 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.

- **Marine Fuels**:

The International Maritime Organization ("IMO") implemented a new regulation (IMO 2020) effective January 1, 2020, that placed sulphur content limits of 0.5% (previously 3.5%) on marine fuel oil consumed by vessels. In the Company's North American operations, IMO 2020 is anticipated to have a net positive impact as a large percentage of SCO from the Company's Oil Sands Mining and Upgrading operations 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%.

In 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.

GHG regulations have been in effect in the UK 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. Following the UK's withdrawal from the European Union ("EU") on January 31, 2020, the UK will continue to participate in the EU ETS for the 2020 compliance year, with decisions on the post-2020 GHG regulatory framework expected in 2020. The Company continues to focus on implementing CO_2 emissions reduction programs based on efficiency audits 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 ("CDI"), 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 CDI is 25% which is applicable to non PSA income.

In 2019, the CDI government communicated its intent to require the oil and gas sector operating in its jurisdiction to comply with the West African Economic and Monetary Union currency control regulations. The Company is in discussions with the applicable authorities to find a mechanism that will comply with these regulations while, at the same time, allow for the expatriation of foreign currency not required for use by the Company in country.

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

During the fourth quarter of 2018, the Gabonese Republic approved the 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. The Company has substantially completed its field decommissioning activities and is proceeding to finalize its exit from the jurisdiction.

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

Given the dynamic nature of risk, the Company uses a multidisciplinary Enterprise Risk Management ("ERM") framework to identify, assess, and mitigate risks that may affect the Company and its operations. The ERM framework incorporates a matrix approach to risk assessment that categorizes and aligns risks across operational areas, allowing teams to better understand the identified risks, their impacts on the Company's operations and the mitigation being undertaken to address these risks. This allows management to monitor potential risk exposures and the steps taken to address the identified risks or otherwise mitigate these exposures by identifying those individuals on the Company's Management Committee responsible for each of the identified risks. Reporting on the risks and related mitigating activity throughout the Company is also part of the ERM framework.

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. This could include: a delay or cancellation of existing or future drilling, development, construction or expansion programs; 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.

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 OPEC and non-OPEC countries, the economic condition of Canada, the US, the European Union and Asia, 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, 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. An ongoing failure to resolve such constraints may extend the duration of discounted or reduced commodity prices realized by crude oil and natural gas producers, including the Company.

Any substantial or extended decline in prices of crude oil or natural gas could result in a delay or cancellation of existing or future drilling, development, construction or expansion programs, including, without limitation, at Horizon, AOSP, Primrose, Pelican Lake, Kirby, Jackfish, and international projects, or curtailment in production at some properties, or

result in unutilized long term transportation commitments, all of which could have a material adverse effect on the Company's financial condition.

Approximately 28% of the Company's 2019 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.

The Company conducts periodic assessments of the carrying value of its assets in accordance with IFRS. If crude oil and natural gas forecast prices decline, the carrying value of related property, plant and equipment could be subject to downward revisions, and net earnings could be adversely affected.

Operational Risk

Exploring for, producing, mining, extracting, upgrading and transporting crude oil, natural gas and NGLs involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. These activities are subject to a number of hazards which may result in fires, explosions, spills, blow outs or other unexpected or dangerous conditions causing personal injury, property damage, environmental damage, interruption of operations and loss of production, whether caused by human error or nature. In addition to the foregoing, the oil sands mining and upgrading operations are also subject to loss of production, potential shutdowns and increased production 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.

Extreme weather events may pose risks to the Company's operations. A comprehensive corporate Emergency Management program is in place to coordinate the Company's response to potential accidents and incidents (including extreme weather events). This program includes Emergency Response Plans (ERPs) intended to ensure a prompt initial response and efficient management of situations as they arise.

The jurisdictions where the Company 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, US, UK, 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. A summary of key environmental risks is set out below:

- **Carbon/GHG Emissions Management Risk**

  As part of its evaluation of climate change risk, the Company reviews independent external scenario analyses developed by energy firms and agencies representing a range of hypothetical paths of development. These external scenario analyses are a tool used by the Company to support business planning, identification of risks and opportunities, and include the consideration of a number of variables and assumptions related to markets, commodity prices, policy, regulation, technology, efficiency and reputation and incorporate a range of assumptions for lower carbon emissions environments. Aspects of climate change risk that have the most potential to influence the Company's business strategy include: future regulatory changes and associated compliance costs, commodity price, access to markets and capital, social preferences and reputational risk, and technology development, as described in more detail below.

- **Future Regulatory Changes / Compliance Costs**

  The additional requirements of enacted or proposed GHG regulations on the Company's operations may increase capital expenditures and production expenses, 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. Accordingly, existing and proposed 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, introduction of 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 emissions 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 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.

- **Access to Markets**

  The Company may be exposed to greater market risk for its products associated with the shift to a lower carbon emissions future. These risks may include increases in the demand for renewable energy sources, increases in compliance costs that may not be recoverable in the price of the product, which could delay the development of certain assets, and restricted access to markets for higher carbon energy sources. This could result in a competitive disadvantage if producers in other jurisdictions are not subject to similar regulatory burdens.

- **Social Preferences / Reputational Risk**

  Changes in public support for climate action, combined with increased activism and opposition to fossil fuels, particularly to oil sands, may impact the market for the Company's products and securities and impact its ability to obtain approvals for new projects and raise capital.

- **Technology Development**

  Regulatory and policy changes to address climate change may require the Company to develop or adopt new sustainable technologies to reduce its environmental footprint and to support the transition to a lower carbon emissions/energy efficient economy at significant cost. In addition, the development and emergence of renewable energy sources could affect the demand for the Company's products thereby affecting its competitiveness and profitability.

- **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 various regulatory processes to obtain project approvals and permits. These processes may include Indigenous and other stakeholder consultation, environmental impact assessments and public hearings. The Company's project execution and timelines could be impacted by delays experienced through the regulatory process or by conditions placed on its operations through permit approvals. Changes in government policy, such as the federal government's Impact Assessment Act, have the potential to impact the certainty and timelines for the regulatory process on large energy projects, including increased requirements for Indigenous consultation.

- **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.

  While the Company continues to implement and adhere to the conditions stipulated in the approved Tailings Management Plans ("TMP") for the Horizon Mine, and the AOSP's Muskeg River Mine and Jackpine Mine and thereby meet 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 exceeding 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. Research and mitigative technologies are in development to reduce fluid tailings and to increase the certainty of achieving the tailings targets for the Horizon and AOSP mines. Through COSIA, technology development is jointly undertaken by all oil sands mine operators to accelerate the commercialization of such projects.

  In September 2018, the Company acquired the Joslyn oil sands project (now referred to as "Horizon South"). To address regulatory requirements and prior to any development, the AER requires the Company to file an updated mine plan that includes tailings and closure planning considerations in an integrated TMP that addresses both Horizon and Horizon South, which is in progress.

  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.

- **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 use planning may set aside areas for conservation, parks, or establish operational constraints to protect biodiversity and wildlife that may place limits on crude oil and natural gas development. Management frameworks in the Lower Athabasca oil sands area establish limits and triggers for surface and ground water quality and quantity, and air emissions that could increase the standards for operation of facilities. Draft frameworks on biodiversity may establish further limits on development that may limit operations and expansion 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. Federal and provincial standards governing the treatment and release of water from oil sands into the environment are currently under development having regard to applicable regulations governing other mining operations in Canada.

  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. Avoidance of caribou habitat and mitigation activities such as accelerated reclamation, maternity pens to raise young caribou, and access management, are being undertaken to improve caribou habitat and increase herd populations.

Reserves Replacement

The Company's future crude oil and natural gas 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, the Company 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 as a result of newly acquired technical data, technology improvements, or changes in historical performance, production costs, development costs, product pricing, economic conditions, market availability, or regulatory requirements. 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, 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. The Company'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

The Company 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 the Company`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. Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital consisting of cash flows from operating activities, available credit facilities, commercial paper, and access to debt capital markets, to meet obligations as they become due.

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.

The Company'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 may periodically 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 the 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, the 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.

In addition, epidemics or pandemics, such as the newly identified COVID-19 virus pandemic, have the potential to disrupt the Company's operations, projects, and financial condition through the disruption of the local or global supply chain and transportation services, or the loss of manpower resulting from quarantines that affect the Company's labour pools in their local communities, workforce camps or operating sites or that are instituted by local health authorities as a precautionary measure, any of which may require the Company to temporarily reduce or shutdown its operations depending on the extent and severity of a potential outbreak and the areas or operations impacted. Depending on the severity, a large scale epidemic or pandemic could impact the international demand for commodities and have a corresponding impact on the prices realized by the Company for its products, which could have a material adverse affect on the Company's financial condition.

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, 2019, 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, 2019 and a preparation date of February 3, 2020. 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 and prepared 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 99 to 106 which is incorporated herein by reference.

Information in the reserves data tables may not add due to rounding. BOE values and oil and gas metrics may not calculate due to rounding.

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 that the estimated reserves will be recovered. Actual crude oil, natural gas and NGLs reserves may be greater or less than the estimate provided herein. Refer to the "Special Note Regarding Forward-Looking Statements", and the "Special Note Regarding Currency, Financial Information, Production and Reserves" in the "Advisory"; and the "Risk Factors" section of this AIF.

Oil and Gas Reserves Tables and Notes

Summary of Company Gross Reserves

As of December 31, 2019
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	97	103	235	653	6,219	3,150	92	7,925
Developed Non-Producing	12	14	—	14	—	162	6	72
Undeveloped	56	85	58	1,771	133	3,083	177	2,794
Total Proved	165	202	293	2,438	6,352	6,395	275	10,791
Probable	64	91	132	1,670	545	3,118	133	3,156
Total Proved plus Probable	229	293	425	4,108	6,897	9,513	408	13,947
North Sea								
Proved								
Developed Producing	37					10		39
Developed Non-Producing	4					1		4
Undeveloped	68					5		69
Total Proved	109					16		112
Probable	67					5		68
Total Proved plus Probable	176					21		179
Offshore Africa								
Proved								
Developed Producing	32					29		37
Developed Non-Producing	12					6		13
Undeveloped	39					13		41
Total Proved	83					48		91
Probable	31					24		35
Total Proved plus Probable	114					72		126
Total Company								
Proved								
Developed Producing	166	103	235	653	6,219	3,189	92	8,001
Developed Non-Producing	28	14	—	14	—	169	6	90
Undeveloped	163	85	58	1,771	133	3,101	177	2,903
Total Proved	357	202	293	2,438	6,352	6,460	275	10,993
Probable	162	91	132	1,670	545	3,147	133	3,258
Total Proved plus Probable	519	293	425	4,108	6,897	9,607	408	14,252

Summary of Company Net Reserves

As of December 31, 2019
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	86	86	183	533	5,288	2,869	73	6,727
Developed Non-Producing	10	12	—	12	—	148	4	63
Undeveloped	48	74	48	1,419	102	2,778	151	2,304
Total Proved	144	171	231	1,963	5,390	5,795	229	9,095
Probable	54	75	96	1,323	447	2,761	107	2,562
Total Proved plus Probable	198	246	327	3,287	5,836	8,556	336	11,657
North Sea								
Proved								
Developed Producing	37					10		39
Developed Non-Producing	4					1		4
Undeveloped	67					5		68
Total Proved	109					16		111
Probable	67					5		67
Total Proved plus Probable	175					21		179
Offshore Africa								
Proved								
Developed Producing	29					24		33
Developed Non-Producing	10					5		10
Undeveloped	31					8		33
Total Proved	70					37		76
Probable	23					16		26
Total Proved plus Probable	93					52		102
Total Company								
Proved								
Developed Producing	152	86	183	533	5,288	2,904	73	6,799
Developed Non-Producing	24	12	—	12	—	153	4	78
Undeveloped	147	74	48	1,419	102	2,792	151	2,405
Total Proved	323	171	231	1,963	5,390	5,849	229	9,282
Probable	144	75	96	1,323	447	2,781	107	2,655
Total Proved plus Probable	467	246	327	3,287	5,836	8,630	336	11,938

Reconciliation of Company Gross Reserves

As of December 31, 2019
Forecast Prices and Costs

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, 2018	194	182	305	1,540	6,091	6,597	267	9,679
Discoveries	—	—	—	—	—	—	—	—
Extensions	3	6	—	17	385	112	11	440
Infill Drilling	5	5	—	—	—	206	8	52
Improved Recovery	—	—	—	237	—	2	—	238
Acquisitions	2	46	—	769	—	35	1	823
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(3)	(3)	(3)	—	—	(228)	(5)	(53)
Technical Revisions	(16)	(3)	12	(64)	20	198	11	(8)
Production	(19)	(30)	(21)	(61)	(144)	(527)	(16)	(380)
December 31, 2019	**165**	**202**	**293**	**2,438**	**6,352**	**6,395**	**275**	**10,791**

North Sea								
December 31, 2018	119					27		124
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	(2)					—		(2)
Technical Revisions	2					(2)		2
Production	(10)					(9)		(12)
December 31, 2019	**109**					**16**		**112**

Offshore Africa								
December 31, 2018	86					28		90
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	5					29		10
Production	(8)					(9)		(9)
December 31, 2019	**83**					**48**		**91**

Total Company								
December 31, 2018	399	182	305	1,540	6,091	6,652	267	9,893
Discoveries	—	—	—	—	—	—	—	—
Extensions	3	6	—	17	385	112	11	440
Infill Drilling	5	5	—	—	—	206	8	52
Improved Recovery	—	—	—	237	—	2	—	238
Acquisitions	2	46	—	769	—	35	1	823
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(5)	(3)	(3)	—	—	(228)	(5)	(54)
Technical Revisions	(9)	(3)	12	(64)	20	225	11	3
Production	(37)	(30)	(21)	(61)	(144)	(544)	(16)	(401)
December 31, 2019	**357**	**202**	**293**	**2,438**	**6,352**	**6,460**	**275**	**10,993**

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, 2018	74	70	140	1,519	941	3,036	130	3,379
Discoveries	—	—	—	—	—	—	—	—
Extensions	1	6	—	9	(385)	65	7	(351)
Infill Drilling	2	2	—	—	—	270	7	56
Improved Recovery	—	—	—	91	—	1	—	91
Acquisitions	—	22	—	186	—	7	—	210
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	—	(1)	—	—	—	(37)	—	(7)
Technical Revisions	(13)	(8)	(7)	(135)	(10)	(224)	(11)	(222)
Production	—	—	—	—	—	—	—	—
December 31, 2019	**64**	**91**	**132**	**1,670**	**545**	**3,118**	**133**	**3,156**
North Sea								
December 31, 2018	67	—	—	—	—	11	—	69
Discoveries	—	—	—	—	—	—	—	—
Extensions	—	—	—	—	—	—	—	—
Infill Drilling	—	—	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	2	—	—	—	—	—	—	2
Technical Revisions	(2)	—	—	—	—	(7)	—	(3)
Production	—	—	—	—	—	—	—	—
December 31, 2019	**67**	**—**	**—**	**—**	**—**	**5**	**—**	**68**
Offshore Africa								
December 31, 2018	35	—	—	—	—	35	—	41
Discoveries	—	—	—	—	—	—	—	—
Extensions	—	—	—	—	—	—	—	—
Infill Drilling	—	—	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—
Technical Revisions	(4)	—	—	—	—	(11)	—	(6)
Production	—	—	—	—	—	—	—	—
December 31, 2019	**31**	**—**	**—**	**—**	**—**	**24**	**—**	**35**
Total Company								
December 31, 2018	176	70	140	1,519	941	3,082	130	3,489
Discoveries	—	—	—	—	—	—	—	—
Extensions	1	6	—	9	(385)	65	7	(351)
Infill Drilling	2	2	—	—	—	270	7	56
Improved Recovery	—	—	—	91	—	1	—	91
Acquisitions	—	22	—	186	—	7	—	210
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	1	(1)	—	—	—	(37)	—	(6)
Technical Revisions	(19)	(8)	(7)	(135)	(10)	(241)	(11)	(231)
Production	—	—	—	—	—	—	—	—
December 31, 2019	**162**	**91**	**132**	**1,670**	**545**	**3,147**	**133**	**3,258**

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, 2018	268	252	445	3,059	7,032	9,633	397	13,058
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	12	—	26	—	177	17	89
Infill Drilling	6	7	—	—	—	476	15	108
Improved Recovery	—	—	—	329	—	3	—	329
Acquisitions	2	68	—	955	—	42	1	1,033
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(4)	(3)	(3)	—	—	(266)	(6)	(60)
Technical Revisions	(29)	(12)	4	(198)	9	(26)	(1)	(230)
Production	(19)	(30)	(21)	(61)	(144)	(527)	(16)	(380)
December 31, 2019	**229**	**293**	**425**	**4,108**	**6,897**	**9,513**	**408**	**13,947**

North Sea								
December 31, 2018	186					38		193
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	—					(9)		(2)
Production	(10)					(9)		(12)
December 31, 2019	**176**					**21**		**179**

Offshore Africa								
December 31, 2018	121					63		131
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	—					18		3
Production	(8)					(9)		(9)
December 31, 2019	**114**					**72**		**126**

Total Company								
December 31, 2018	575	252	445	3,059	7,032	9,734	397	13,382
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	12	—	26	—	177	17	89
Infill Drilling	6	7	—	—	—	476	15	108
Improved Recovery	—	—	—	329	—	3	—	329
Acquisitions	2	68	—	955	—	42	1	1,033
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(4)	(3)	(3)	—	—	(266)	(6)	(60)
Technical Revisions	(28)	(12)	4	(198)	9	(16)	(1)	(228)
Production	(37)	(30)	(21)	(61)	(144)	(544)	(16)	(401)
December 31, 2019	**519**	**293**	**425**	**4,108**	**6,897**	**9,607**	**408**	**14,252**

Notes to Reserves Tables

1. “Company gross reserves” are the Company's working interest share of reserves before deduction of royalties and without including any royalty interests of the Company.

2. “Company net reserves” 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 of 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, product price 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. Reserves reconciliation change category definitions:

   - "Discoveries" means additions to reserves in reservoirs where no reserves were previously booked.
   - "Extensions" means additions to reserves resulting from step-out drilling or recompletions.
   - "Infill Drilling" means additions to reserves resulting from drilling or recompletions within the known boundaries of a reservoir.
   - "Improved Recovery" means additions to reserves resulting from the implementation of improved recovery schemes.
   - 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.
   - "Economic Factors" means changes primarily due to price forecasts.
   - "Technical Revisions" include changes in previous estimates resulting from new technical data or revised interpretations and changes in operating costs, capital costs and offsets to product reference pricing.

7. 2019 reserves reconciliation highlights:

Total Proved Crude Oil, Bitumen (Thermal Oil) and NGLs reserves increased by 1,132 MMbbl:

- Extensions: Increase of 421 MMbbl primarily due to the transfer of reserves from the probable category at Oil Sands Mining and Upgrading (SCO) and extension drilling/future offset additions at various Bitumen (Thermal Oil), Primary Heavy Crude Oil, Light Crude Oil and natural gas (NGLs) properties.
- Infill Drilling: Increase of 17 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 238 MMbbl primarily due to increased steamflood recovery of Bitumen (Thermal Oil) at Primrose.
- Acquisitions: Increase of 818 MMbbl primarily due to Bitumen (Thermal Oil) and Primary Heavy Crude Oil property acquisitions from Devon.
- Economic Factors: Decrease of 16 MMbbl primarily due to lower product pricing.
- Technical Revisions: Decrease of 35 MMbbl primarily due to Bitumen (Thermal Oil) 50 year reserves life cutoff at Primrose, the removal of future extension and infill undeveloped reserves in certain Light Crude Oil properties because of revised Company development plans, reduced performance in certain Light and Primary Heavy Crude Oil properties and reclassification of some Light Crude Oil to Natural Gas, offset by improved performance at Pelican Lake (Pelican Lake Heavy Crude Oil) and various natural gas (NGLs) properties, as well as positive technical revisions at Oil Sands Mining and Upgrading (SCO) due to improved mining performance and mine plan changes.
- Production: Decrease of 310 MMbbl.

Total Proved Natural Gas reserves decreased by 192 Bcf:

- Extensions: Increase of 112 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Infill Drilling: Increase of 206 Bcf primarily due to infill drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Improved Recovery: Increase of 2 Bcf.
- Acquisitions: Increase of 35 Bcf primarily due to property acquisitions in North America core areas.
- Economic Factors: Decrease of 228 Bcf due to uneconomic reserves in several North America Natural Gas areas.
- Technical Revisions: Increase of 225 Bcf primarily due to overall positive revisions in several North America and Offshore Africa core areas as a result of increased recovery and category transfers from probable to proved.
- Production: Decrease of 544 Bcf.

Total Proved plus Probable Crude Oil, Bitumen and NGLs reserves increased by 891 MMbbl:

- Extensions: Increase of 60 MMbbl primarily due to future Bitumen (Thermal Oil) well pad additions and extension drilling/future offset additions at various Light Crude Oil, Primary Heavy Crude Oil and natural gas (NGLs) properties.
- Infill Drilling: Increase of 28 MMbbl primarily due to infill drilling/future offset additions at various Light Crude Oil, Primary Heavy Crude Oil and natural gas (NGLs) properties.
- Improved Recovery: Increase of 329 MMbbl primarily due to increased steamflood recovery of Bitumen (Thermal Oil) at Primrose.
- Acquisitions: Increase of 1,026 MMbbl primarily due to (Bitumen (Thermal Oil)) and Primary Heavy Crude Oil property acquisitions from Devon.
- Economic Factors: Decrease of 16 MMbbl primarily due to lower product pricing.
- Technical Revisions: Decrease of 225 MMbbl primarily due to Bitumen (Thermal Oil) 50 year reserves life cutoff at Primrose, the removal of future extension and infill undeveloped reserves in certain Light Crude Oil properties because of revised Company development plans, reduced performance in certain Light and Primary Heavy Crude Oil properties and reclassification of some Light Crude Oil to Natural Gas, offset by improved performance at Pelican Lake (Pelican Lake Heavy Crude Oil) and various natural gas (NGLs) properties, as well as positive technical revisions at Oil Sands Mining and Upgrading (SCO) due to improved mining performance and mine plan changes.
- Production: Decrease of 310 MMbbl.

Total Proved plus Probable Natural Gas reserves decreased by 128 Bcf:

- Extensions: Increase of 177 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Infill Drilling: Increase of 476 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 42 Bcf primarily due to property acquisitions in North America core areas.
- Economic Factors: Decrease of 266 Bcf due to uneconomic reserves in several North America Natural Gas areas.
- Technical Revisions: Decrease of 16 Bcf primarily due to overall negative revisions in the probable category as a result of 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, offset by increased recovery at Offshore Africa.
- Production: Decrease of 544 Bcf.

8. 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.

Future Net Revenue Tables and Notes

The following tables summarize the future net revenue as of December 31, 2019 using forecast prices and costs. Abandonment, Decommissioning and Reclamation ("ADR") costs included in the calculation of future net revenue consist of both the Company's total Asset Retirement Obligation ("ARO"), before inflation and discounting, for development existing as of December 31, 2019 and forecast estimates of ADR costs attributable to future development activity.

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

As of December 31, 2019
Forecast Prices and Costs

($ millions)	Discount @ 0%	Discount @ 5%	Discount @ 10%	Discount @ 15%	Discount @ 20%	Unit Value Discounted at 10%/year ($/BOE)
North America						
Proved						
Developed Producing	358,797	142,711	82,852	58,765	46,216	12.32
Developed Non-Producing	1,279	886	659	514	415	10.45
Undeveloped	68,435	35,887	19,153	11,078	6,818	8.31
Total Proved	428,510	179,484	102,664	70,357	53,449	11.29
Probable	116,148	36,791	17,166	10,170	6,949	6.70
Total Proved plus Probable	544,659	216,276	119,830	80,527	60,398	10.28
North Sea						
Proved						
Developed Producing	(829)	297	634	731	748	16.36
Developed Non-Producing	150	127	109	95	83	25.66
Undeveloped	3,360	2,661	2,163	1,796	1,517	31.63
Total Proved	2,681	3,085	2,906	2,621	2,348	26.09
Probable	4,468	3,006	2,205	1,722	1,407	32.67
Total Proved plus Probable	7,149	6,091	5,111	4,343	3,755	28.57
Offshore Africa						
Proved						
Developed Producing	638	780	779	737	688	23.61
Developed Non-Producing	623	459	354	283	233	33.76
Undeveloped	1,872	1,241	870	638	484	26.68
Total Proved	3,133	2,480	2,003	1,658	1,404	26.32
Probable	1,976	1,232	824	584	435	31.93
Total Proved plus Probable	5,109	3,712	2,827	2,242	1,839	27.74
Total Company						
Proved						
Developed Producing	358,605	143,788	84,266	60,233	47,652	12.39
Developed Non-Producing	2,052	1,472	1,121	891	731	14.42
Undeveloped	73,667	39,789	22,187	13,512	8,819	9.22
Total Proved	434,324	185,049	107,573	74,635	57,201	11.59
Probable	122,593	41,029	20,194	12,476	8,791	7.61
Total Proved plus Probable	556,917	226,079	127,768	87,112	65,992	10.70

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

As of December 31, 2019
Forecast Prices and Costs

($ millions)	Discount @ 0%	Discount @ 5%	Discount @ 10%	Discount @ 15%	Discount @ 20%
North America					
Proved					
Developed Producing	275,036	110,963	65,140	46,561	36,817
Developed Non-Producing	983	673	494	381	304
Undeveloped	53,541	27,232	14,134	7,904	4,657
Total Proved	329,561	138,868	79,767	54,845	41,778
Probable	89,103	27,978	12,933	7,597	5,154
Total Proved plus Probable	418,664	166,846	92,700	62,443	46,933
North Sea					
Proved					
Developed Producing	(718)	121	375	451	469
Developed Non-Producing	28	58	60	56	51
Undeveloped	2,417	1,768	1,394	1,145	964
Total Proved	1,726	1,946	1,828	1,652	1,484
Probable	2,675	1,819	1,349	1,064	878
Total Proved plus Probable	4,401	3,766	3,178	2,716	2,361
Offshore Africa					
Proved					
Developed Producing	463	637	659	635	599
Developed Non-Producing	472	349	270	217	180
Undeveloped	1,427	955	676	499	382
Total Proved	2,362	1,941	1,605	1,352	1,161
Probable	1,483	932	628	449	337
Total Proved plus Probable	3,845	2,873	2,234	1,801	1,498
Total Company					
Proved					
Developed Producing	274,781	111,722	66,174	47,647	37,885
Developed Non-Producing	1,482	1,080	824	654	535
Undeveloped	57,385	29,954	16,203	9,548	6,004
Total Proved	333,649	142,755	83,201	57,849	44,423
Probable	93,261	30,730	14,910	9,111	6,369
Total Proved plus Probable	426,910	173,485	98,111	66,960	50,792

Total Future Net Revenue (Undiscounted)

As of December 31, 2019
Forecast Prices and Costs

	North America		North Sea		Offshore Africa		Total	
($ millions)	Proved	Proved plus Probable	Proved	Proved plus Probable	Proved	Proved plus Probable	Proved	Proved plus Probable
Revenue	998,735	1,256,468	11,574	19,464	6,895	9,305	1,017,204	1,285,237
Royalties	163,182	213,923	24	43	231	326	163,437	214,292
Production Costs	306,111	376,528	5,511	8,374	2,286	2,502	313,907	387,404
Development Costs	81,230	100,673	1,257	1,796	755	862	83,242	103,332
ADR Costs for Future Development	619	986	—	—	30	45	648	1,032
Future Net Revenue Before Income Taxes **Excluding ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)**	447,593	564,358	4,782	9,251	3,593	5,569	455,969	579,178
ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	19,083	19,700	2,101	2,101	460	460	21,644	22,261
Future Net Revenue Before Income Taxes **Including ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)**	428,510	544,659	2,681	7,149	3,133	5,109	434,324	556,917
Income Taxes	98,950	125,995	955	2,749	771	1,264	100,676	130,007
Future Net Revenue After Income Taxes	**329,561**	**418,664**	**1,726**	**4,401**	**2,362**	**3,845**	**333,649**	**426,910**

Future Net Revenue By Product Type

As of December 31, 2019
Forecast Prices and Costs

Proved Reserves

Product Type	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($ millions)	Unit Value ($/BOE)
Light and Medium Crude Oil (including solution gas and other by-products)	9,361	20.99
Primary Heavy Crude Oil (including solution gas)	2,026	11.71
Pelican Lake Heavy Crude Oil (including solution gas)	3,449	14.90
Bitumen (Thermal Oil)	22,727	11.58
Synthetic Crude Oil	67,478	12.52
Natural Gas (including by-products but excluding solution gas and by-products from crude oil wells)	4,645	4.31
Total **Excluding ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)**	109,687	11.82
ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	(2,113)	
Total Including ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	**107,573**	**11.59**

Proved plus Probable Reserves

Product Type	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($ millions)	Unit Value ($/BOE)
Light and Medium Crude Oil (including solution gas and other by-products)	13,878	21.74
Primary Heavy Crude Oil (including solution gas)	3,205	12.89
Pelican Lake Heavy Crude Oil (including solution gas)	4,596	14.03
Bitumen (Thermal Oil)	28,035	8.53
Synthetic Crude Oil	73,036	12.51
Natural Gas (including by-products but excluding solution gas and by-products from crude oil wells)	7,194	4.50
Total **Excluding ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)**	129,944	10.89
ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	(2,176)	
Total Including ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	**127,768**	**10.70**

Notes to Future Net Revenue Tables

1. Abandonment, Decommissioning and Reclamation ("ADR") costs included in the calculation of the future net revenue consist of both the Company's total Asset Retirement Obligation ("ARO"), before inflation and discounting, for development existing as of December 31, 2019 and forecast estimates of ADR costs attributable to future development activity. The Company's total ARO included in the reserves future net revenue is escalated at the rate of inflation described in the "Pricing Assumptions" section of this AIF.
2. For reserves in Canada, future net revenue includes carbon cost compliance in accordance with current provincial and federal regulations which reaches $50/tonne by 2022. For reserves in the North Sea, future net revenue includes carbon cost compliance in accordance with the UK Carbon Emissions Tax which reaches approximately $28/tonne after 2020.
3. Unit values ($/BOE) are based on company net reserves.
4. 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, 2019.
5. Future net revenue is prior to provision for interest, general and administrative expenses, and the impact of any risk management activities.

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, 2019. The following is a summary of the Sproule price forecast. All prices increase at a rate of 2% per year after 2024.

	2020	2021	2022	2023	2024
Crude Oil and NGLs					
WTI (US$/bbl)	61.00	65.00	67.00	68.34	69.71
WCS (C$/bbl)	59.81	63.98	63.77	65.04	66.34
Canadian Light Sweet (C$/bbl)	73.84	78.51	78.73	80.30	81.91
Cromer LSB (C$/bbl)	73.84	77.51	77.73	79.30	80.91
Edmonton C5+ (C$/bbl)	76.32	80.52	80.00	81.68	83.38
North Sea Brent (US$/bbl)	65.00	68.00	70.00	71.40	72.83
Natural Gas					
AECO (C$/MMBtu)	2.04	2.27	2.81	2.89	2.98
BC Westcoast Station 2 (C$/MMBtu)	1.54	1.87	2.41	2.49	2.58
Henry Hub (US$/MMBtu)	2.80	3.00	3.25	3.32	3.38

Notes to Pricing Assumptions Table

1. Reference pricing definitions:
   - "WTI" refers to the price of West Texas Intermediate crude oil at Cushing, Oklahoma.
   - "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.
   - "Canadian Light Sweet" refers to the price of light gravity (40º 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.
   - "Cromer LSB" refers to the price of light sour blend (35º 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.
   - "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.
   - "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.

- "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.
- "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.
- "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.

2. 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.
3. The Company's 2019 average pricing, net of blending costs and excluding risk management activities, was $75.25/bbl for light and medium crude oil, $55.38/bbl for primary heavy crude oil, $57.82/bbl for Pelican Lake heavy crude oil, $48.27/bbl for bitumen (thermal oil), $70.18/bbl for SCO, $29.35/bbl for NGLs, and $2.34/Mcf for natural gas.
4. Production and capital costs are escalated at Sproule's cost inflation rate of 0% per year for 2020, 1% per year for 2021 and 2% per year after 2021 for all products.
5. Sproule's foreign exchange rate of 0.76 US$/C$ for 2020, 0.77 US$/C$ for 2021 and 0.80 US$/C$ after 2021 was used in the 2019 evaluation.

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. Undeveloped reserves additions result from one or more of the following: acquisitions, infill and extension drilling, or improved recovery in the year when the events first occurred. 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)
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
2019								
First Attributed	7	21	—	538	133	297	17	765
Total	163	85	58	1,771	133	3,101	177	2,903

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)
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
2019								
First Attributed	3	25	—	166	—	330	14	262
Total	79	63	28	1,406	157	2,127	103	2,191

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 61% of the Company's total proved undeveloped BOE reserves and 64% 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 the Company'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 using Sproule's inflation and foreign exchange rates as of December 31, 2019. Future development costs exclude all Abandonment, Decommissioning and Reclamation ("ADR") costs. ADR costs are included in the calculation of the future net revenue and consist of both the Company's total Asset Retirement Obligation ("ARO"), before inflation and discounting, for development existing as of December 31, 2019 and forecast estimates of ADR costs attributable to future development activity.

Future Development Costs (Undiscounted)

($millions)	2020	2021	2022	2023	2024	Thereafter	Total	Total Discounted at 10%
Proved								
North America	2,436	3,509	3,681	3,125	2,707	65,772	81,230	27,409
North Sea	213	170	137	130	68	538	1,257	821
Offshore Africa	72	229	117	41	37	258	755	521
Total Proved	2,722	3,908	3,935	3,297	2,813	66,568	83,242	28,750
Proved plus Probable								
North America	2,606	3,726	3,848	3,292	2,936	84,265	100,673	31,782
North Sea	217	174	141	158	73	1,033	1,796	958
Offshore Africa	72	229	159	90	37	275	862	593
Total Proved plus Probable	2,896	4,129	4,147	3,540	3,046	85,573	103,332	33,333

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.

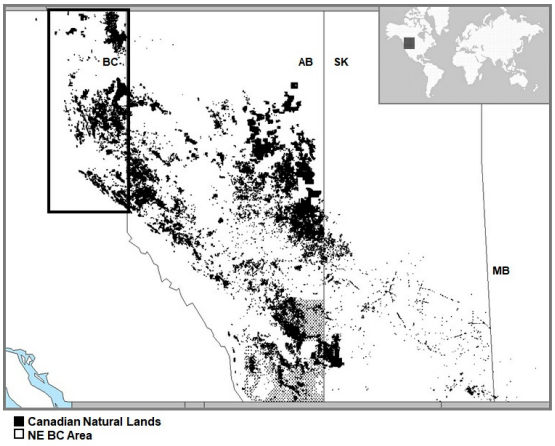
Other Oil and Gas Information

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, 2019 and 2018.

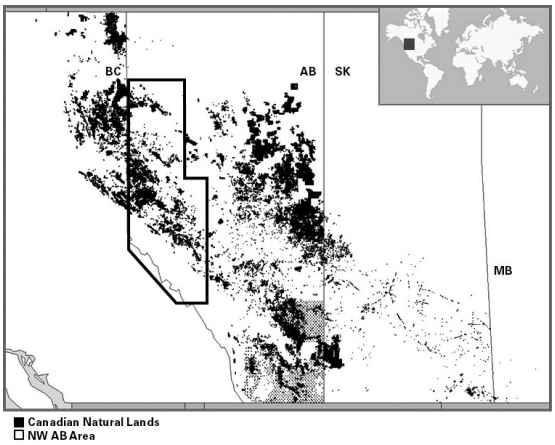
	2019 Average Daily Production Rates		2018 Average Daily Production Rates	
Region	**Crude Oil & NGLs (Mbbl)**	**Natural Gas (MMcf)**	Crude Oil & NGLs (Mbbl)	Natural Gas (MMcf)
North America				
Northeast British Columbia	**13**	**346**	13	345
Northwest Alberta	**52**	**675**	46	667
Northern Plains	**317**	**167**	268	194
Southern Plains	**17**	**252**	18	282
Southeast Saskatchewan	**7**	**3**	6	2
Oil Sands Mining & Upgrading	**395**	**—**	426	—
North America Total	**801**	**1,443**	777	1,490
International				
North Sea UK Sector	**28**	**24**	24	32
Offshore Africa	**21**	**24**	20	26
International Total	**49**	**48**	44	58
Company Total	**850**	**1,491**	821	1,548

Northeast British Columbia



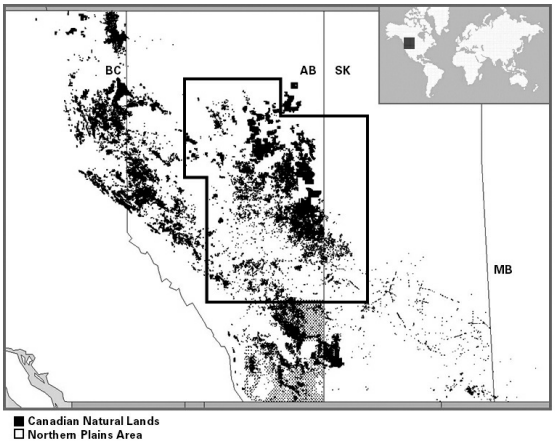
The Northeast British Columbia Region holds a significant portion of the Montney formation. This formation produces liquids rich natural gas and light oil from several stratigraphic intervals. The exploration strategy focuses on comprehensive evaluation through two dimensional seismic, three dimensional 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.

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 10°-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 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 pipeline 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 three major oil batteries with a capacity of 85,000 bbl/d. The Company is using an EOR scheme through polymer flooding to increase the ultimate recoveries from the field.

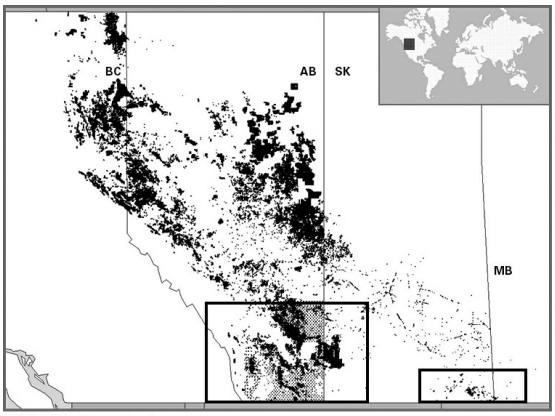
Production of bitumen (thermal oil) from the 100% owned Primrose and Wolf Lake Fields located near Bonnyville, Alberta, involves processes that utilize steam to increase the recovery of the bitumen. The processes employed by the Company are CSS, SAGD and steamflood. These recovery processes inject steam to heat the bitumen deposits, reducing the viscosity and thereby improving its flow characteristics. There is also an infrastructure of gathering systems and a processing plant at Wolf Lake with capacity of 140,000 bbl/d. The Company holds a 50% interest in a co-generation facility capable of producing 84 megawatts of electricity. The Company continues to optimize the CSS, and steamflood processes which results in significant improvements in well productivity and in ultimate bitumen recovery. Pad additions at Primrose North were brought on production in 2019.

The 100% owned Kirby South field located near Lac la Biche, Alberta, involves SAGD process recovery and has an infrastructure and plant processing capacity of 40,000 bbl/d.

In 2016, the Company re-initiated the development of the Kirby North SAGD Project and engineering and procurement commenced in 2017. The majority of the Kirby North Project was completed with initial production in May 2019. The final pad drilling commenced in late 2019 and will be completed in April 2020. Production continues to ramp up to Kirby North's overall capacity of 40,000 bbl/d of SAGD production.

On June 27, 2019, the Company completed its acquisition of substantially all of the assets of Devon, which included a 100% interest in the operating thermal SAGD assets of Devon at Jackfish and a 50% interest in the undeveloped Pike lands adjacent to Jackfish. The infrastructure at Jackfish consists of three processing plants and gathering systems that have a combined capacity of 120,000 bbl/d. The acquisition also included 95% operated conventional primary heavy crude oil production and 1.5 million acres of land of which 1 million acres is undeveloped. The acquired thermal and primary heavy crude assets are located adjacent to existing Company assets.

Southern Plains and Southeast Saskatchewan

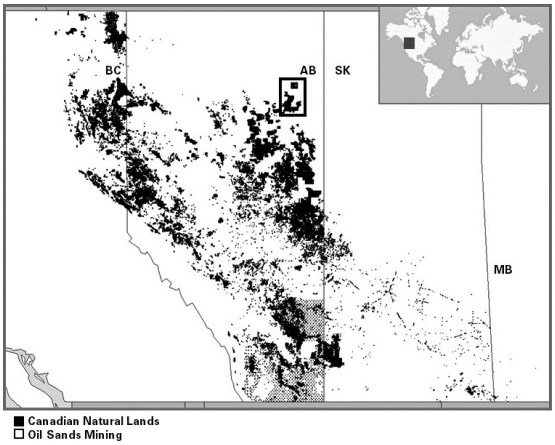


The Southern Plains region is principally located south of the Northern Plains region to the United States border and extending into western Saskatchewan.

Reserves of natural gas, NGLs and light and medium crude oil are contained in numerous productive horizons at depths up to 2,300 meters. 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 multiple productive horizons found at depths up to 2,700 meters.

Oil Sands Mining and Upgrading



Horizon: The Company 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.

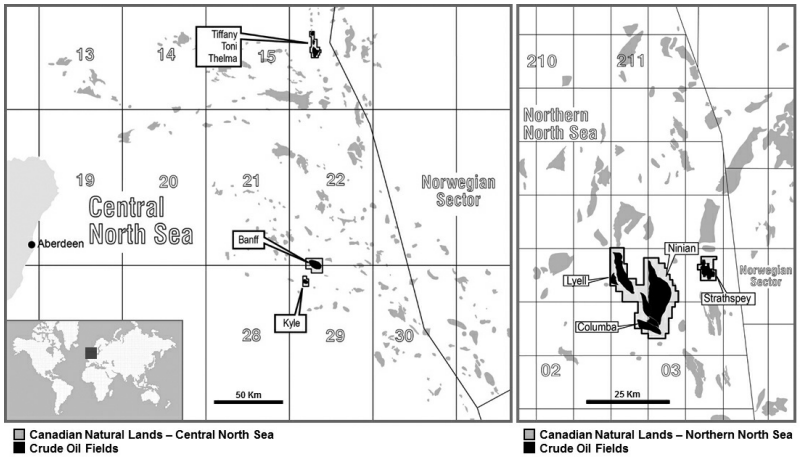
In the third quarter of 2018, the Company acquired the Joslyn oil sands project, adding to the Company's total oil sands mining and upgrading reserves. This incorporation of the Joslyn leases (now, Horizon South) to the mine plan will allow mining to continue south of the previously existing Horizon 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 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 production capacity of the combined AOSP mines is 320,000 bbl/d of bitumen. 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 in 2019 the remaining major application approvals were obtained.

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 2019, 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. 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 the central portion of the North Sea, the Company holds a 100% operated working interest in the T-block (comprising the Tiffany, Toni and Thelma fields).

The Company also holds an 87.6% operated working interest in the Banff field and a 45.7% operated working interest in the Kyle field. Production from the Kyle field is processed through the Banff FPSO. The Company is preparing a decommissioning programme for the Banff and Kyle fields and anticipates the cessation of production and commencement of decommissioning activities at both fields in 2020.

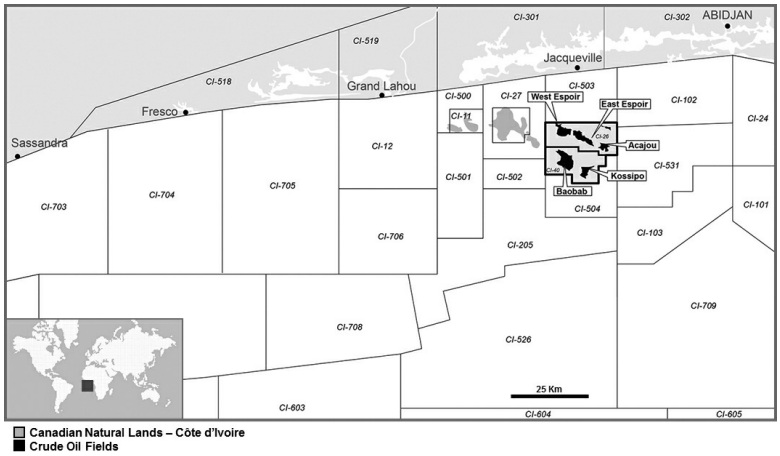
The Company receives tariff revenue from other field owners for the processing of crude oil and natural gas through certain processing facilities.

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 substantially complete in 2020.

The Company commenced abandonment of the Ninian North Platform in the second quarter of 2017. The offshore decommissioning activities are targeted to be substantially complete in 2021, with full completion in approximately three years.

Offshore Africa

Côte d'Ivoire

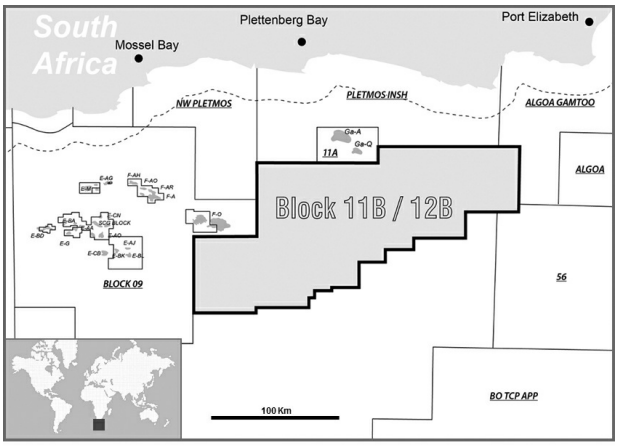


The Company owns interests in two licences offshore Côte d'Ivoire.

The Company has a 58.7% operated working 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 working 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.

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% non-operated 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 operator has contracted a drilling rig to commence further exploration activity in 2020. 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

The following table summarizes the number of wells in which the Company has a working interest that were producing or mechanically capable of producing as of December 31, 2019.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	26,380	21,417.6	11,845	10,763.5	38,225	32,181.1
British Columbia	1,813	1,643.1	215	196.0	2,028	1,839.1
Saskatchewan	10,203	9,329.9	2,563	1,552.5	12,766	10,882.4
Manitoba	—	—	159	140.9	159	140.9
Total Canada	38,396	32,390.6	14,782	12,652.9	53,178	45,043.5
United States Louisiana	—	—	2	0.4	2	0.4
North Sea UK Sector	1	0.7	57	54.4	58	55.1
Offshore Africa						
Côte d'Ivoire	—	—	26	15.1	26	15.1
Gabon	—	—	—	—	—	—
Total	38,397	32,391.3	14,867	12,722.8	53,264	45,114.1

The following table summarizes 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, 2019.

	Natural Gas Wells		Crude Oil Wells		Total Wells	
Non-Producing	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	10,173	8,191.0	12,119	10,844.6	22,292	19,035.6
British Columbia	2,471	2,116.1	556	482.9	3,027	2,599.0
Saskatchewan	2,105	1,978.0	4,136	2,892.1	6,241	4,870.1
Manitoba	—	—	134	85.3	134	85.3
Northwest Territories	89	20.6	—	—	89	20.6
Total Canada	14,838	12,305.7	16,945	14,304.9	31,783	26,610.6
United States Louisiana	—	—	1	0.2	1	0.2
North Sea UK Sector	2	1.5	21	18.8	23	20.3
Offshore Africa						
Côte d'Ivoire	—	—	14	8.1	14	8.1
Gabon	—	—	13	12.0	13	12.0
Total	14,840	12,307.2	16,994	14,344.0	31,834	26,651.2

Properties With No Attributed Reserves

The following table summarizes the Company's unproved property as of December 31, 2019.

Country (thousands of acres)	Gross	Net
Canada	25,992	20,910
US	3	2
North Sea UK Sector	65	60
Côte d'Ivoire	92	53
Gabon	—	—
South Africa	4,002	800
Company Total	**30,153**	**21,826**

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.

The Company has approximately 0.5 million net acres attributed to the North America properties which are currently expected to expire by December 31, 2020.

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.

2019 COSTS INCURRED IN CRUDE OIL, NATURAL GAS AND NGLs ACTIVITIES

($ millions)	North America	North Sea	Offshore Africa	Total
Property Acquisitions				
Proved	3,405	—	—	3,405
Unproved	91	—	—	91
Exploration	38	—	33	71
Development	4,687	349	233	5,269
	8,221	349	266	8,836
Add: Net non-cash and other costs (1)	(1,865)	(153)	(37)	(2,055)
Costs Incurred	6,356	196	229	6,781

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

Exploration and Development Activities

The following table summarizes the crude oil and natural gas drilling activities completed by the Company for the year ended December 31, 2019. Total success rate for 2019, excluding service and stratigraphic test wells, was 97%.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Canada – Exploration and Production				
Crude Oil	2	2.0	88	78.0
Natural Gas	18	8.2	12	10.8
Dry	—	—	3	3.0
Service	—	—	17	17.0
Stratigraphic	—	—	44	44.0
Total	20	10.2	164	152.8
Canada – Oil Sands Mining & Upgrading				
Service	—	—	10	8.4
Stratigraphic	—	—	443	374.6
Total	—	—	453	383.0
Total Canada	20	10.2	617	535.8
North Sea UK Sector				
Crude Oil	—	—	5	4.9
Service	—	—	2	1.9
Côte d'Ivoire				
Crude Oil	—	—	1	0.6
Service	—	—	2	1.1
Stratigraphic	1	0.6	—	—
Total International	1	0.6	10	8.5
Company Total	21	10.8	627	544.3

2020 ACTIVITY

Effective and efficient operations will continue to be a focus of the Company in 2020. Our 2020 capital budget is flexible and disciplined and was originally targeted, when finalized on December 4, 2019, to be approximately $4,050 million, driving corporate production guidance volumes between 1,137,000 and 1,207,000 BOE/d. Subsequent to year end 2019, in early March 2020, as a result of the volatility in crude oil pricing, the Company reduced its 2020 capital budget by approximately $100 million to $3,950 million. With the continued volatility in commodity pricing, the Company has identified and implemented further opportunities to reduce its 2020 capital spending budget to approximately $2,960 million with no impact to its earlier stated production guidance of between 1,137,000 and 1,207,000 BOE/d. Decisions regarding additional opportunities to further reduce capital spending will be made as part of the Company's management of its capital expenditures.

PRODUCTION ESTIMATES

The following table summarizes the estimated 2020 company gross proved and probable daily production included in the estimates of proved reserves and probable reserves as of December 31, 2019 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	44,775	76,705	57,934	239,505	395,998	1,205	37,407	1,053,162
North Sea	35,243	—	—	—	—	23	—	39,014
Offshore Africa	17,104	—	—	—	—	21	—	20,649
Total Proved	97,121	76,705	57,934	239,505	395,998	1,249	37,407	1,112,825
PROBABLE								
North America	3,460	5,448	2,112	230	22,839	80	3,467	50,865
North Sea	6,657	—	—	—	—	3	—	7,077
Offshore Africa	609	—	—	—	—	1	—	741
Total Probable	10,726	5,448	2,112	230	22,839	83	3,467	58,683

Production History

	2019				
	Q1	Q2	Q3	Q4	Year Ended
North America Production and Netbacks by Product					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	51,117	56,118	53,965	52,429	53,412
Netbacks ($/bbl)					
Sales price	65.24	71.65	64.67	62.27	66.05
Transportation	3.63	3.78	3.81	3.61	3.71
Royalties	6.55	8.30	8.58	8.14	7.92
Production expenses	22.25	20.24	20.06	21.69	21.02
Netback	**32.81**	**39.33**	**32.22**	**28.83**	**33.40**
Primary Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	68,473	77,667	88,008	94,262	82,189
Netbacks ($/bbl)					
Sales price	52.27	64.71	55.47	49.72	55.38
Transportation	3.47	4.03	3.56	3.63	3.67
Royalties	6.42	8.76	8.10	8.69	8.06
Production expenses	17.30	17.52	17.08	15.03	16.66
Netback	**25.08**	**34.40**	**26.73**	**22.37**	**26.99**
Pelican Lake Heavy Crude Oil					
Average daily production (before royalties) (bbl/d)	61,240	55,031	60,146	59,013	58,855
Netbacks ($/bbl)					
Sales price	56.28	66.71	56.75	51.66	57.82
Transportation	5.49	5.74	5.34	5.03	5.40
Royalties	10.72	12.79	12.28	12.81	12.15
Production expenses	6.69	6.72	6.10	5.38	6.22
Netback	**33.38**	**41.46**	**33.03**	**28.44**	**34.05**
Bitumen (Thermal Oil)					
Average daily production (before royalties) (bbl/d)	94,146	109,599	206,395	259,387	167,942
Netbacks ($/bbl)					
Sales price	48.27	57.61	49.80	42.93	48.27
Transportation	2.88	3.09	4.55	4.04	3.87
Royalties	4.36	4.68	4.65	4.63	4.61
Production expenses	17.95	11.84	9.77	8.65	10.83
Netback	**23.08**	**38.00**	**30.83**	**25.61**	**28.96**
SCO					
Average daily production (before royalties) (bbl/d)	416,206	374,500	432,203	357,856	395,133
Netbacks ($/bbl)					
Sales price	65.86	74.98	71.60	68.67	70.18
Transportation	1.17	1.53	1.16	1.33	1.29
Royalties	2.31	3.79	3.76	3.47	3.31
Production expenses	21.46	24.17	18.82	23.02	21.75
Netback	**40.92**	**45.49**	**47.86**	**40.85**	**43.83**
Natural Gas					
Average daily production (before royalties) (MMcf/d)	1,454	1,482	1,425	1,411	1,443
Netbacks ($/Mcf)					
Sales price	2.88	1.84	1.51	2.52	2.18
Transportation	0.45	0.39	0.38	0.42	0.41
Royalties	0.11	0.07	0.01	0.11	0.07
Production expenses	1.30	1.15	1.07	1.11	1.16
Netback	**1.02**	**0.23**	**0.05**	**0.88**	**0.54**

	2019				
	Q1	Q2	Q3	Q4	Year Ended
Natural Gas Liquids					
Average daily production (before royalties) (bbl/d)	44,461	46,250	42,148	41,480	43,572
Netbacks ($/bbl)					
Sales price	30.58	30.90	27.09	28.65	29.35
Transportation	2.07	2.22	2.16	2.01	2.12
Royalties	3.32	0.56	1.22	2.17	1.80
Production expenses	8.50	7.91	8.43	7.57	8.10
Netback	**16.69**	**20.21**	**15.28**	**16.90**	**17.33**
North Sea Production and Netbacks by Product					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	25,714	27,594	27,454	30,860	27,919
Netbacks ($/bbl)					
Sales price	87.61	88.25	83.64	87.76	86.76
Transportation	1.48	1.01	0.64	0.66	0.86
Royalties	0.13	0.22	0.17	0.13	0.16
Production expenses	39.68	37.31	37.11	33.67	36.39
Netback	**46.32**	**49.71**	**45.72**	**53.30**	**49.35**
Natural Gas					
Average daily production (before royalties) (MMcf/d)	28	23	20	25	24
Netbacks ($/MMcf)					
Sales price	10.05	5.34	4.67	5.10	6.52
Transportation	1.37	1.36	1.15	1.23	1.29
Royalties	—	—	—	—	—
Production expenses	2.41	5.09	3.08	3.25	3.40
Netback	**6.27**	**(1.11)**	**0.44**	**0.62**	**1.83**
Offshore Africa Production and Netbacks by Product (1)					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	22,155	23,650	21,227	18,495	21,371
Netbacks ($/bbl)					
Sales price	81.00	95.33	82.97	70.73	83.68
Transportation	—	—	—	—	—
Royalties	6.93	3.85	4.43	4.60	4.74
Production expenses	9.79	8.40	11.06	16.75	11.21
Netback	**64.28**	**83.08**	**67.48**	**49.38**	**67.73**
Natural Gas					
Average daily production (before royalties) (MMcf/d)	28	27	24	19	24
Netbacks ($/Mcf)					
Sales price	7.34	6.94	7.08	8.58	7.41
Transportation	0.18	0.18	0.18	0.19	0.18
Royalties	0.85	0.59	0.63	0.39	0.63
Production expenses	2.12	2.49	2.78	3.19	2.60
Netback	**4.19**	**3.68**	**3.49**	**4.81**	**4.00**

Notes to Production History Tables

1. Netback values expressed on a per unit basis are based on sales volumes.
2. Sale Price is net of blending costs and excludes risk management activities.
3. For SCO only: sales price is also net of feedstock costs; average daily production excludes 3,370 bbl/d of SCO consumed internally as diesel; royalty expense is calculated based on bitumen royalties expensed during the period divided by the corresponding SCO sales volumes; and production expenses are adjusted cash production costs based on sales volumes excluding turnaround periods.

Selected Financial Information

($ millions, except per common share amounts)		2019	2018
Product sales		**$ 24,394**	$ 22,282
Crude oil and NGLs		**$ 22,950**	$ 20,668
Natural gas		**$ 1,419**	$ 1,614
Net earnings		**$ 5,416**	$ 2,591
Per common share	– basic	**$ 4.55**	$ 2.13
	– diluted	**$ 4.54**	$ 2.12
Adjusted net earnings from operations (1)		**$ 3,795**	$ 3,263
Per common share	– basic	**$ 3.19**	$ 2.68
	– diluted	**$ 3.18**	$ 2.67
Cash flows from operating activities		**$ 8,829**	$ 10,121
Adjusted funds flow (1)		**$ 10,267**	$ 9,088
Per common share	– basic	**$ 8.62**	$ 7.46
	– diluted	**$ 8.61**	$ 7.43
Total assets		**$ 78,121**	$ 71,559
Total long-term liabilities		**$ 36,493**	$ 34,823
Cash flows used in investing activities		**$ 7,255**	$ 4,814
Net capital expenditures (2)(3)		**$ 7,121**	$ 4,731

Notes to Selected Financial Information

1. Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. Adjusted funds flow (previously referred to as "funds flow from operations") is a non-GAAP measure that the Company considers key to evaluate its performance 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 derivation of these two non-GAAP measures is discussed in the "Advisory" section of this AIF. A reconciliation 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, 2019.
2. Net capital expenditures is a non-GAAP measure that the Company considers a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. A reconciliation of the non-GAAP measure net capital expenditures is provided in the "Net Capital Expenditures" section of the Company's MD&A for the year ended December 31, 2019.
3. Total net capital expenditures in 2019 included Devon acquisition costs.

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.

	2019	2018	2017
Cash dividends declared per common share	**$ 1.50**	**$ 1.34**	$ 1.10

(1) On March 4, 2020, the Board of Directors approved an increase in the quarterly dividend to $0.425 per common share, beginning with the dividend payable on April 1, 2020.

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 the Company, to receive such dividends as declared by the Board of Directors on the common shares and to receive pro-rata the remaining property and assets of the Company upon its dissolution or winding-up, subject to any rights having priority over the common shares.

PREFERRED SHARES

The Company has no preferred shares outstanding. The Company is authorized to issue an unlimited number of Preferred Shares issuable in one or more series. The directors of the Company are authorized to determine, before the issue thereof, the number of shares in each series and to determine the designation, rights, privileges, restrictions and conditions attaching to the Preferred Shares of each series.

CREDIT RATINGS

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

Credit ratings accorded to the Company’s debt securities are not recommendations to purchase, hold or sell the debt securities inasmuch as such ratings do not comment on the current market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant, and if any such rating is so revised or withdrawn, the Company is under no obligation to update this AIF.

	Senior Unsecured Debt Securities	Commercial Paper	Outlook/Trend (1)
Moody’s Investors Service, Inc. (“Moody’s”) (2)	Baa2	P-2	Stable
S&P Global Ratings (“S&P”) (2)	BBB+	A-2	Stable
DBRS Limited (“DBRS”) (2)	BBB (high)	-	Stable

(1) The above ratings for Moody's, S&P and DBRS reflect the Company's ratings as at December 31, 2019. Moody’s and S&P assign a rating outlook to the Company and not to individual long-term debt instruments.

(2) Following the change in commodity prices in March 2020, Moody’s, S&P and DBRS made announcements regarding the Company’s ratings. Moody’s affirmed the Company’s Baa2 senior unsecured rating and P-2 commercial paper rating, with a stable outlook. S&P lowered its long term issuer credit rating of the Company and for senior unsecured debt to BBB and affirmed the Company’s A-2 rating for commercial paper, with a stable outlook. DBRS announced that the Company’s rating was put under review with negative implications.

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 appends 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 obligation 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 obligation 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

weaken the obligor's capacity 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.

The Company 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. The Company 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 2019.

	2019 Monthly Historical Trading on TSX			
Month	High	Low	Close	Volume Traded (Shares)
January	$ 37.33	$ 31.52	$ 35.27	74,615,710
February	$ 38.14	$ 33.76	$ 37.38	52,170,334
March	$ 38.45	$ 34.50	$ 36.69	114,497,619
April	$ 42.56	$ 36.20	$ 40.22	71,505,951
May	$ 40.34	$ 34.25	$ 36.51	75,242,425
June	$ 37.07	$ 34.60	$ 35.31	69,591,151
July	$ 36.48	$ 31.96	$ 33.43	50,764,079
August	$ 33.20	$ 30.01	$ 31.81	60,664,429
September	$ 38.00	$ 30.73	$ 35.25	115,371,931
October	$ 35.68	$ 32.26	$ 33.21	57,091,335
November	$ 37.85	$ 33.46	$ 37.11	61,517,537
December	$ 42.40	$ 35.91	$ 42.00	100,979,876

On May 21, 2019, 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 59,729,706 common shares, over a 12-month period commencing May 23, 2019 and ending May 22, 2020. The Company's NCIB announced in March 2018 expired on May 22, 2019.

During 2019, the Company purchased for cancellation 25,900,000 common shares at a weighted average price of $36.32 per common share. From January 1, 2020 to March 18, 2020, the Company purchased 6,970,000 common shares at a weighted average price of $38.84 per common share.

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 18, 2020 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 66)	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 and Badger Daylighting 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.
M. Elizabeth Cannon, Ph.D., O.C. Calgary, Alberta Canada	Director (age 57)	Corporate director. She is currently President Emerita and Professor of Engineering at the University of Calgary, having previously served at the University of Calgary as Dean of the Schulich School of Engineering from 2006-2010, and then as President and Vice Chancellor from 2010-2018. She was appointed as a director of the Company on November 5, 2019.
N. Murray Edwards, O.C. St. Moritz, Switzerland	Executive Chairman and Director (age 60)	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 (3)(5) (age 75)	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 ICE Futures Europe. Mr. Faithfull will not be standing for re-election at the Annual Meeting to be held on May 7, 2020.
Christopher L. Fong Calgary, Alberta Canada	Director (3)(5) (age 70)	Corporate director. He has served continuously as a director of the Company since November 2010. He is currently serving on the board of directors of Computer Modelling Group Ltd.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Ambassador Gordon D. Giffin Atlanta, Georgia U.S.A	Director (1)(4) (age 70)	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.
Wilfred A. Gobert Calgary, Alberta Canada	Director (1)(2)(4) (age 72)	Independent businessman. He has served continuously as a director since November 2010. He is currently serving on the board of directors of Paramount Resources Ltd.
Steve W. Laut Calgary, Alberta Canada	Executive Vice Chairman and Director (5)(6) (age 62)	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 58)	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 72)	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 70)	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 63)	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.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Troy J.P. Andersen Calgary, Alberta Canada	Senior Vice-President, Canadian Conventional Field Operations (age 41)	Officer of the Company.
Trevor J. Cassidy Calgary, Alberta Canada	Senior Vice-President, Thermal (age 46)	Officer of the Company.
Réal M. Cusson Calgary, Alberta Canada	Senior Vice-President, Marketing (age 69)	Officer of the Company.
Darren M. Fichter Calgary, Alberta Canada	Chief Operating Officer, Exploration and Production (age 49)	Officer of the Company.
Allan E. Frankiw Calgary, Alberta Canada	Senior Vice-President, Production (age 63)	Officer of the Company.
Jay E. Froc Calgary, Alberta Canada	Senior Vice-President, Oil Sands Mining and Upgrading (age 54)	Officer of the Company.
Ronald K. Laing Calgary, Alberta Canada	Senior Vice-President, Corporate Development and Land (age 50)	Officer of the Company.
Pamela A. McIntyre Calgary, Alberta Canada	Senior Vice-President, Safety, Risk Management and Innovation (age 57)	Officer of the Company.
Paul M. Mendes Calgary, Alberta Canada	Vice-President, Legal, General Counsel and Corporate Secretary (age 54)	Officer of the Company.
William R. Peterson Calgary, Alberta Canada	Senior Vice-President, Development Operations (age 53)	Officer of the Company.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Kendall W. Stagg Calgary, Alberta Canada	Senior Vice-President, Exploration (age 58)	Officer of the Company.
Mark A. Stainthorpe Calgary, Alberta Canada	Chief Financial Officer and Senior Vice-President, Finance(7) (age 42)	Officer of the Company since March 2018. Prior thereto Manager, Investor Relations until May 2015, Manager, Treasury from May 2015 to February 2016, Director, Treasury and Investor Relations from March 2016 to March 2018, and most recently Vice-President, Finance - Capital Markets from March 2018 to March 2019.
Scott G. Stauth Calgary, Alberta Canada	Chief Operating Officer, Oil Sands (age 54)	Officer of the Company.
Betty Yee Calgary, Alberta Canada	Vice-President, Land (age 55)	Officer of the Company.
Robin S. Zabek Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 48)	Officer of the Company.

(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) Mr. Steve W. Laut will step back as Executive Vice-Chairman on or before the Annual Meeting on May 7, 2020 and will stand for re-election to the Board of Directors at the 2020 Annual Meeting.
(7) Mr. Mark A. Stainthorpe replaced Mr. Corey B. Bieber as Chief Financial Officer and Senior Vice-President, Finance effective March 29, 2019. Mr. Bieber continues with the Company as Executive Advisor and as a member of the Company's Management Committee.

All directors stand for election at each Annual Meeting of the Company's Shareholders. All of the current directors were elected to the Board at the last Annual and Special Meeting of the Company's Shareholders held on May 9, 2019 with the exception of Dr. M. Elizabeth Cannon, who was appointed to the Board of Directors effective November 5, 2019.

As at December 31, 2019, 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 1,187 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, the Company 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, 2019, 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 the Company, 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 4, 2020 in respect of the Company’s consolidated financial statements as at December 31, 2019 and December 31, 2018 and for each of the three years in the period ended December 31, 2019 and the Company’s internal control over financial reporting as at December 31, 2019. 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. G. D. Giffin, W.A. Gobert 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.

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. W.A. Gobert holds an MBA (Finance) degree from McMaster University as well as a Bachelor of Science (Honours) degree from the University of Windsor and holds a Chartered Financial Analyst (CFA) designation. Mr. Gobert was Vice Chair of Peters & Co. Limited, an independent, fully integrated investment dealer specializing in providing comprehensive investment research, and acting as an active underwriter and financial advisor specializing in the Canadian energy sector. During his 27 year career with Peters & Co. Limited, Mr. Gobert developed expertise in connection with the review, analysis and evaluation of financial statements that presented a variety of complex accounting issues and subsequently supervised and oversaw individuals directly engaged in the review, analysis and evaluation of similarly complex financial disclosure. As a result, Mr. Gobert developed an understanding of generally accepted accounting principles, financial statements, internal controls and financial reporting. Mr. Gobert 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.

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 2019 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)	**2019**	2018
Audit fees	**$ 2,580**	$ 2,597
Audit related fees	**536**	425
Tax fees	**426**	443
All other fees	**32**	30
Total	**$ 3,574**	$ 3,495

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

ADDITIONAL INFORMATION

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

Additional information including Directors' and Executive Officers' remuneration and indebtedness, Director nominees standing for re-election, principal holders of the Company's securities, options to purchase the Company's securities and interest of insiders in material transactions is contained in the Company's Notice of Annual Meeting and Information Circular dated March 18, 2020 in connection with the Annual Meeting of Shareholders of the Company to be held on May 7, 2020 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, Consolidated Financial Statements and Supplementary Oil & Gas Information for the most recently completed fiscal year ended December 31, 2019 found on pages 10 to 49, 56 to 98 and 99 to 106 respectively, of the 2019 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 North America, United Kingdom and Offshore Africa petroleum and natural gas reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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, 2019, 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, 2019	Canada and USA	—	46,370	1,491	47,861
Sproule International Limited	December 31, 2019	United Kingdom and Offshore Africa	—	7,938	—	7,938
Total			**—**	**54,308**	**1,491**	**55,799**

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 4, 2020

Original Signed By

SIGNED "GARY R. FINNIS"
Gary R. Finnis, P.Eng.
Senior Manager, Engineering

Original Signed By

SIGNED "NORA T. STEWART"
Nora T. Stewart, P.Eng.
Senior Vice President

Original Signed By

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

Sproule International Limited
Calgary, Alberta, Canada,
March 4, 2020

Original Signed By

SIGNED "MEGHAN M. KLEIN"
Meghan M. Klein, P.Eng.
Senior Manager, Engineering

Original Signed By

SIGNED "SCOTT W. PENNELL"
Scott W. Pennell, P.Eng.
COO

Original Signed By

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

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 the Company's Canadian Oil Sands Mining and Upgrading reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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.
3. We carried out our evaluation 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 to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation 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 for the year ended December 31, 2019, and identifies the respective portions thereof that we have evaluated 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
GLJ Petroleum Consultants Ltd.	December 31, 2019	Canada	—	71,969	—	71,969
Total			**—**	**71,969**	—	**71,969**

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.

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada,
March 4, 2020

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 "MARK A. STAINTHORPE"
Mark A. Stainthorpe
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 4th day of March, 2020

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

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

Consolidated Financial Statements

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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, 2019; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2019.

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 "MARK STAINTHORPE"	SIGNED "RONALD D. KIM"
TIM S. MCKAY	**MARK STAINTHORPE**, **CFA**	**RONALD D. KIM, CA**
President	Chief Financial Officer and Senior Vice-President, Finance	Vice-President, Finance and Principal Accounting Officer

Calgary, Alberta, Canada
March 18, 2020

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, 2019. 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, 2019, as stated in their accompanying Report of Independent Registered Public Accounting Firm.

SIGNED "TIM S. MCKAY"	SIGNED "MARK STAINTHORPE"
TIM S. MCKAY	**MARK STAINTHORPE, CFA**
President	Chief Financial Officer and Senior Vice-President, Finance

Calgary, Alberta, Canada
March 18, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders and 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, 2019 and 2018, and the related consolidated statements of earnings, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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, 2019 and 2018, and its financial performance and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019 due to the adoption of IFRS 16, Leases.

BASIS FOR OPINIONS

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. 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.

CRITICAL AUDIT MATTERS

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The impact of Crude Oil and Natural Gas Reserves on Property, Plant and Equipment Assets in the North America Exploration and Production and Oil Sands Mining and Upgrading segments

As described in Notes 1, 4, and 7 to the Company's consolidated financial statements, the property, plant and equipment ("PP&E") balances in the North America Exploration and Production and Oil Sands Mining and Upgrading segments was $26.1 billion and $38.8 billion, respectively, as at December 31, 2019. Depletion, depreciation and amortization ("DD&A") expense for the North America Exploration and Production and Oil Sands Mining and Upgrading segments was $3.2 billion and $1.6 billion, respectively, for the year ended December 31, 2019. In accordance with the Company's accounting policies, crude oil and natural gas properties in the North America Exploration and Production segment, excluding major components, and mine-related costs in the Oil Sands Mining and Upgrading segment are depleted using the unit-of-production method based on proved reserves. PP&E assets are grouped for recoverability assessment purposes into cash generating units ("CGUs") and a CGU's recoverable amount is the higher of its fair value less costs of disposal and its value in use. The assessment of a CGU's recoverability requires the use of estimates and assumptions, including information on future commodity prices, expected production volumes, quantity of crude oil and natural gas reserves, asset retirement obligations, future development and operating costs, after-tax discount rates, and income taxes. Estimates of the Company's crude oil and natural gas reserves 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.

Management utilizes third party specialists, specifically independent qualified reserve evaluators to evaluate, review and report to the Company's management and Board of Directors on its estimates of crude oil and natural gas reserves. These estimates are utilized for both the determination of the recoverable amounts of PP&E and the calculation of DD&A expense.

The principal considerations for our determination that performing procedures relating to the impact of crude oil and natural gas reserves on PP&E assets in the North America Exploration and Production and Oil Sands Mining and Upgrading segments is a critical audit matter are that there was a significant amount of judgment required by management, including the use of specialists, when developing the estimates, specifically related to the estimates of crude oil and natural gas reserves and the recoverable amount of the PP&E assets in the North America Exploration and Production and Oil Sands Mining and Upgrading segments. This led to a high degree of auditor judgment, effort, and subjectivity in performing procedures and evaluating evidence obtained related to the significant assumptions used in developing the estimates, including estimates of expected future rates of production, future commodity pricing, and future development and operating costs.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of internal controls in the North America Exploration and Production and Oil Sands Mining and Upgrading segments relating to management's estimates of the Company's crude oil and natural gas reserves, management's assessment of PP&E recoverability, and the calculation of DD&A expense. These procedures also included, among others, testing management's process for determining the recoverable amount of the PP&E in the North America Exploration and Production and Oil Sands Mining and Upgrading segments, and DD&A expense for the North America Exploration and Production and Oil Sands Mining and Upgrading segments. Testing management's process for determining these estimates included (i) evaluating the appropriateness of the methods used by management in making these estimates; (ii) testing the completeness, accuracy and relevance of underlying data used in management's analysis in developing these estimates; (iii) evaluating the significant assumptions used in developing the underlying estimates, including assumptions of expected future rates of production, future commodity pricing, and future development and operating costs; and (iv) testing the unit-of-production rates used to calculate DD&A expense. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the estimates of crude oil and natural gas reserves used to determine DD&A expense and the recoverable amounts of PP&E for the North America Exploration and Production and Oil Sands Mining and Upgrading segments. As a basis for using this work, the specialists' qualifications and objectivity were understood, as well as the methods and assumptions used by the specialists. The procedures performed also included tests of data used by the specialists and an evaluation of their findings. Evaluating the significant assumptions used by management's specialists also involved evaluating whether the assumptions used were reasonable considering the past performance of the Company, consistency with industry pricing forecasts, and whether they were consistent with evidence obtained in other areas of the audit.

SIGNED "PricewaterhouseCoopers LLP"

Chartered Professional Accountants

Calgary, Canada
March 18, 2020

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

Consolidated Balance Sheets

As at December 31 (millions of Canadian dollars)	Note	2019	2018
ASSETS			
Current assets			
Cash and cash equivalents		**$ 139**	$ 101
Accounts receivable		**2,465**	1,148
Current income taxes receivable		**13**	—
Inventory	5	**1,152**	955
Prepaids and other		**174**	176
Investments	9	**490**	524
Current portion of other long-term assets	10	**54**	116
		4,487	3,020
Exploration and evaluation assets	6	**2,579**	2,637
Property, plant and equipment	7	**68,043**	64,559
Lease assets	8	**1,789**	—
Other long-term assets	10	**1,223**	1,343
		$ 78,121	$ 71,559
LIABILITIES			
Current liabilities			
Accounts payable		**$ 816**	$ 779
Accrued liabilities		**2,611**	2,356
Current income taxes payable		**—**	151
Current portion of long-term debt	11	**2,391**	1,141
Current portion of other long-term liabilities	8,12	**819**	335
		6,637	4,762
Long-term debt	11	**18,591**	19,482
Other long-term liabilities	8,12	**7,363**	3,890
Deferred income taxes	13	**10,539**	11,451
		43,130	39,585
SHAREHOLDERS' EQUITY			
Share capital	14	**9,533**	9,323
Retained earnings		**25,424**	22,529
Accumulated other comprehensive income	15	**34**	122
		34,991	31,974
		$ 78,121	$ 71,559

Commitments and contingencies (note 20).

Approved by the Board of Directors on March 18, 2020

SIGNED "CATHERINE M. BEST"	SIGNED "N. MURRAY EDWARDS"
CATHERINE M. BEST	**N. MURRAY EDWARDS**
Chair of the Audit Committee and Director	Executive Chairman of the Board of Directors and Director

Consolidated Statements of Earnings

For the years ended December 31 (millions of Canadian dollars, except per common share amounts)	Note		2019		2018		2017 (1)
Product sales	22	$	**24,394**	$	22,282	$	18,360
Less: royalties			**(1,523)**		(1,255)		(1,018)
Revenue			**22,871**		21,027		17,342
Expenses							
Production			**6,277**		6,464		5,675
Transportation, blending and feedstock			**4,699**		4,189		3,529
Depletion, depreciation and amortization	7,8		**5,546**		5,161		5,186
Administration			**344**		325		319
Share-based compensation	12		**223**		(146)		134
Asset retirement obligation accretion	12		**190**		186		164
Interest and other financing expense	18		**836**		739		631
Risk management activities	19		**77**		(134)		35
Foreign exchange (gain) loss			**(570)**		827		(787)
Gain on acquisition, disposition and revaluation of properties	6,7		**—**		(452)		(379)
Loss (gain) from investments	9,10		**293**		346		(38)
			17,915		17,505		14,469
Earnings before taxes			**4,956**		3,522		2,873
Current income tax expense (recovery)	13		**434**		374		(164)
Deferred income tax (recovery) expense	13		**(894)**		557		640
Net earnings		$	**5,416**	$	2,591	$	2,397
Net earnings per common share							
Basic	17	$	**4.55**	$	2.13	$	2.04
Diluted	17	$	**4.54**	$	2.12	$	2.03

(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.

Consolidated Statements of Comprehensive Income

For the years ended December 31 (millions of Canadian dollars)		2019		2018		2017
Net earnings	$	**5,416**	$	2,591	$	2,397
Items that may be reclassified subsequently to net earnings						
Net change in derivative financial instruments designated as cash flow hedges						
Unrealized income, net of taxes of $13 million (2018 – $nil, 2017 – $9 million)		**99**		5		53
Reclassification to net earnings, net of taxes of $5 million (2018 – $6 million, 2017 – $5 million)		**(41)**		(39)		(33)
		58		(34)		20
Foreign currency translation adjustment						
Translation of net investment		**(146)**		224		(158)
Other comprehensive income (loss), net of taxes		**(88)**		190		(138)
Comprehensive income	$	**5,328**	$	2,781	$	2,259

Consolidated Statements of Changes in Equity

For the years ended December 31 (millions of Canadian dollars)	Note	2019	2018	2017
Share capital	14			
Balance – beginning of year		**$ 9,323**	$ 9,109	$ 4,671
Issued upon exercise of stock options		**360**	332	466
Previously recognized liability on stock options exercised for common shares		**53**	120	154
Purchase of common shares under Normal Course Issuer Bid		**(203)**	(238)	—
Issued for the acquisition of AOSP and other assets (1)	7	**—**	—	3,818
Balance – end of year		**9,533**	9,323	9,109
Retained earnings				
Balance – beginning of year		**22,529**	22,612	21,526
Net earnings		**5,416**	2,591	2,397
Dividends on common shares	14	**(1,783)**	(1,630)	(1,311)
Purchase of common shares under Normal Course Issuer Bid	14	**(738)**	(1,044)	—
Balance – end of year		**25,424**	22,529	22,612
Accumulated other comprehensive income (loss)	15			
Balance – beginning of year		**122**	(68)	70
Other comprehensive income (loss), net of taxes		**(88)**	190	(138)
Balance – end of year		**34**	122	(68)
Shareholders' equity		**$ 34,991**	$ 31,974	$ 31,653

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

Consolidated Statements of Cash Flows

For the years ended December 31 (millions of Canadian dollars)	Note	2019	2018	2017
Operating activities				
Net earnings		**$ 5,416**	$ 2,591	$ 2,397
Non-cash items				
Depletion, depreciation and amortization		**5,546**	5,161	5,186
Share-based compensation		**223**	(146)	134
Asset retirement obligation accretion		**190**	186	164
Unrealized risk management loss (gain)		**13**	(35)	37
Unrealized foreign exchange (gain) loss		**(548)**	706	(821)
Realized foreign exchange loss on repayment of US dollar securities		**—**	146	—
Gain on acquisition, disposition and revaluation of properties		**—**	(452)	(379)
Loss (gain) from investments		**321**	374	(11)
Deferred income tax (recovery) expense		**(894)**	557	640
Other		**(109)**	(23)	(110)
Abandonment expenditures		**(296)**	(290)	(274)
Net change in non-cash working capital	21	**(1,033)**	1,346	299
Cash flows from operating activities		**8,829**	10,121	7,262
Financing activities				
Issue (repayment) of bank credit facilities and commercial paper, net	11,21	**2,025**	(1,595)	2,222
(Repayment) issue of medium-term notes	11,21	**(1,000)**	—	1,791
(Repayment) issue of US dollar debt securities	11,21	**—**	(1,236)	2,733
Payment of lease liabilities	8	**(237)**	—	—
Issue of common shares on exercise of stock options		**360**	332	466
Dividends on common shares		**(1,743)**	(1,562)	(1,252)
Purchase of common shares under Normal Course Issuer Bid		**(941)**	(1,282)	—
Cash flows (used in) from financing activities		**(1,536)**	(5,343)	5,960
Investing activities				
Net expenditures on exploration and evaluation assets	21	**(73)**	(266)	(124)
Net expenditures on property, plant and equipment		**(3,535)**	(4,175)	(4,574)
Acquisition of Devon assets (1)	7	**(3,412)**	—	—
Acquisition of AOSP and other assets, net of cash acquired (2)	7	**—**	—	(8,630)
Investment in other long-term assets		**—**	(28)	(87)
Net change in non-cash working capital	21	**(235)**	(345)	313
Cash flows used in investing activities		**(7,255)**	(4,814)	(13,102)
Increase (decrease) in cash and cash equivalents		**38**	(36)	120
Cash and cash equivalents – beginning of year		**101**	137	17
Cash and cash equivalents – end of year		**$ 139**	$ 101	$ 137
Interest paid on long-term debt, net		**$ 865**	$ 911	$ 725
Income taxes paid (received)		**$ 445**	$ (225)	$ (792)

(1) The acquisition of assets from Devon Canada Corporation ("Devon") in 2019 includes net working capital and other long-term assets of $195 million (see note 7).
(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 7).

Notes to the Consolidated Financial Statements

(tabular amounts in millions of Canadian dollars, unless otherwise stated)

1. Accounting Policies

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire 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, in the "Midstream and Refining" segment, the Company maintains certain 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 to upgrade and refine bitumen 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. If the Company's share of the joint venture's loss equals or exceeds its interest in the joint venture, the Company discontinues recognizing its share of further losses. The Company resumes recognizing profits when its share of profits exceeds the accumulated share of losses not recognized.

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 ("FPSO"). 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.

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 certain 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, Refining and Head Office

The Company capitalizes all costs that expand the capacity or extend the useful life of the midstream, refining and head office assets. Midstream and Refining 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. 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

At inception of a contract, the Company assesses whether a contract is, or contains a lease. A contract is, or contains a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, the Company assesses whether: the contract involves the use of an identified asset; the Company has the right to obtain substantially all of the economic benefits from the use of the asset throughout the period of use; and, the Company has the right to direct the use of the asset.

The Company recognizes a lease asset and a lease liability at the commencement date of the lease contract, which is the date that the lease asset is available to the Company. The lease asset is initially measured at cost. The cost of a lease asset includes the amount of the initial measurement of the lease liability, lease payments made prior to the commencement date, initial direct costs and estimates of the asset retirement obligation, if any. Subsequent to initial recognition, the lease asset is depreciated using the straight-line method over the earlier of the end of the useful life of the lease asset or the lease term.

Lease liabilities are initially measured at the present value of lease payments discounted at the rate implicit in the lease, or if not readily determinable, the Company's incremental borrowing rate. Lease payments include fixed lease payments, variable lease payments based on indices or rates, residual value guarantees, and purchase options expected to be exercised. Subsequent to initial recognition, the lease liability is measured at amortized cost using the effective interest method. Lease liabilities are remeasured if there are changes in the lease term or if the Company changes its assessment of whether it is reasonably certain it will exercise a purchase, extension or termination option. Lease liabilities are also remeasured if there are changes in the estimate of the amounts payable under the lease due to changes in indices or rates, or residual value guarantees.

Lease assets are reported in a separate caption in the consolidated balance sheet. Lease liabilities are reported within other long-term liabilities in the consolidated balance sheet.

Depreciation on lease assets used in the construction of property, plant and equipment is capitalized to the cost of those assets over their period of use until such time as the property, plant and equipment is substantially available for its intended use.

Where the Company acts as the operator of a joint operation, the Company recognizes 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 are recognized as other income in the consolidated statements of earnings.

On January 1, 2019 the Company adopted IFRS 16 "Leases" (see note 2) and as permitted in the transition requirements of the standard, the Company continues to account for leases for the years ended December 31, 2018 and 2017 in accordance with the Company's previous accounting policy for leases as follows:

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

(K) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on all of its property, plant and equipment 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.

On January 1, 2018 the Company adopted IFRS 15 "Revenue from Contracts with Customers" and as permitted in the transition requirements of the standard, the Company continues to report revenue for the year ended December 31, 2017 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 Performance Share Unit ("PSU") plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met. PSUs vest three years from original grant date. The liability for PSUs is initially measured in reference to the Company's stock price and the number of awards expected to vest and is re-measured at each reporting period for changes in the fair value of the liability.

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.

On January 1, 2018 the Company adopted IFRS 9 "Financial Instruments" and as permitted in the transition requirements of the standard, the Company continues to report impairment of financial assets for the year ended December 31, 2017 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 16 "LEASES"

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaced IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and generally requires balance sheet recognition for all leases. Certain short-term (12 months or less) and low-value leases are exempt from the requirements, and the Company continues to treat these leases as expenses. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are also exempt from the standard.

The Company adopted IFRS 16 on January 1, 2019 using the modified retrospective approach 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 have not been restated and continue to be reported using the Company's previous accounting policy under IAS 17.

On adoption, the Company applied 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 twelve months or less as at January 1, 2019 were treated as short-term leases;
- exclusion of initial direct costs for the measurement of lease assets at the date of initial application; and
- the application of the Company's previous assessment for onerous contracts under IAS 37, instead of re-assessing impairment on the Company's lease assets as at January 1, 2019.

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

In connection with the adoption of IFRS 16, the Company recognized lease liabilities (included in other long-term liabilities) of $1,539 million, measured at the present value of the remaining lease payments, discounted at the Company's incremental borrowing rate at the transition date. Lease assets were measured at an amount equal to the lease liability. The adoption of IFRS 16 resulted in increases in depletion, depreciation and amortization expense and interest expense and corresponding decreases in production, transportation and administration expenses. Under the new standard, the Company reports cash outflows for payment of the principal portion of the lease liability as cash flows used in financing activities. The interest portion of the lease payments is classified as cash flows from operating activities.

Further details of the Company's lease assets and lease liabilities on transition to the new Leases standard at January 1, 2019 and as at December 31, 2019 are shown in note 8.

CHANGES IN OTHER ACCOUNTING POLICIES

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 the joint venture. The Company retrospectively adopted the amendments on January 1, 2019. These amendments did not have a significant impact on the Company's 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 Company adopted the interpretation on January 1, 2019. The interpretation did not have a significant impact on the Company's consolidated financial statements.

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 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 prospectively adopted the amendments on January 1, 2020.

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 prospectively adopted the amendments on January 1, 2020.

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) LEASES

Purchase, extension and termination options are included in certain of the Company's leases to provide operational flexibility. To measure the lease liability, the Company uses judgment to assess the likelihood of exercising these options. These assessments are reviewed when significant events or circumstances indicate that the likelihood of exercising these options may have changed. The Company also uses estimates to determine its incremental borrowing costs if the interest rate implicit in the lease is not readily determinable.

(J) 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

		2019		2018
Product inventory	**$**	**468**	$	297
Materials and supplies		**684**		658
	$	**1,152**	$	955

The Company recorded a write-down of its product inventory of $4 million from cost to net realizable value as at December 31, 2019 (2018 – $13 million).

6. Exploration and Evaluation Assets

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
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
Additions	**38**	**—**	**33**	**—**	**71**
Acquisition of Devon assets (note 7)	**91**	**—**	**—**	**—**	**91**
Transfers to property, plant and equipment	**(219)**	**—**	**—**	**—**	**(219)**
Foreign exchange adjustments	**—**	**—**	**(1)**	**—**	**(1)**
At December 31, 2019	**$ 2,258**	**$ —**	**$ 69**	**$ 252**	**$ 2,579**

On June 27, 2019, the Company completed the acquisition of substantially all of the assets of Devon including thermal in situ and heavy crude oil assets, for total cash purchase consideration of $3,412 million, including $91 million of exploration and evaluation assets (see note 7).

During 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.

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 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.

During 2018, 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 or natural gas discovery on the exploration right and conversion to a production right, additional cash payments would 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 and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2017	$ 64,816	$ 7,126	$ 4,881	$ 42,084	$ 428	$ 414	$ 119,749
Additions (1)	2,428	237	212	1,050	13	21	3,961
Transfers from E&E assets	175	—	—	222	—	—	397
Disposals/derecognitions and other	(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
Additions	**2,613**	**349**	**233**	**2,154**	**10**	**34**	**5,393**
Acquisition of Devon assets	**3,325**	**—**	**—**	**—**	**—**	**—**	**3,325**
Transfers from E&E assets	**219**	**—**	**—**	**—**	**—**	**—**	**219**
Disposals/derecognitions (2)	**(537)**	**—**	**(1,515)**	**(285)**	**—**	**(3)**	**(2,340)**
Foreign exchange adjustments and other	**—**	**(374)**	**(256)**	**—**	**—**	**—**	**(630)**
At December 31, 2019	**$ 72,627**	**$ 7,296**	**$ 3,933**	**$ 45,016**	**$ 451**	**$ 466**	**$ 129,789**
Accumulated depletion and depreciation							
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
Expense	**3,215**	**256**	**214**	**1,564**	**15**	**23**	**5,287**
Disposals/derecognitions (2)	**(537)**	**—**	**(1,515)**	**(285)**	**—**	**(3)**	**(2,340)**
Foreign exchange adjustments and other	**18**	**(279)**	**(190)**	**(13)**	**—**	**—**	**(464)**
At December 31, 2019	**$ 46,577**	**$ 5,712**	**$ 2,712**	**$ 6,247**	**$ 153**	**$ 345**	**$ 61,746**
Net book value							
- at December 31, 2019	**$ 26,050**	**$ 1,584**	**$ 1,221**	**$ 38,769**	**$ 298**	**$ 121**	**$ 68,043**
- at December 31, 2018	$ 23,126	$ 1,586	$ 1,268	$ 38,166	$ 303	$ 110	$ 64,559

(1) Additions in North Sea during 2018 include a pre-tax revaluation gain of $19 million relating to acquisitions of its previously held interest.
(2) Following demobilization of the FPSO at the Olowi field, Gabon in2019, the Company derecognized property, plant and equipment and associated accumulated depletion and depreciation of $1,515 million.

Acquisitions in the current and comparative years have been accounted for as business combinations 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.

During 2019, the Company acquired a number of producing crude oil and natural gas properties in the North America Exploration and Production segment, excluding the impact of acquisitions disclosed below, for net cash consideration of $80 million (2018 – $170 million; 2017 – $1,013 million including $27 million of exploration and evaluation assets) and assumed associated asset retirement obligations of $20 million (2018 – $13 million; 2017 – $63 million). No net deferred income tax liabilities were recognized (2018 – $nil; 2017 – $nil) and no pre-tax gains were recognized on these net transactions (2018 – pre-tax gain of $47 million; 2017 – $nil).

During 2018, 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 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).

In connection with the acquisition of pipeline system assets in the Midstream and Refining 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, 2019, 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.

As at December 31, 2019, the Company recognized certain project costs, not subject to depletion and depreciation, of $115 million in the Oil Sands Mining and Upgrading segment (2018 – $1,424 million in the North America Exploration and Production segment). As at December 31, 2018, project costs not subject to depletion and depreciation primarily related to the Kirby North project, which was fully commissioned in 2019.

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 2019, pre-tax interest of $53 million (2018 – $69 million; 2017 – $82 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 4.0% (2018 – 3.9%; 2017 – 3.8%).

ACQUISITION OF THERMAL IN SITU AND PRIMARY HEAVY CRUDE OIL ASSETS

On June 27, 2019, the Company completed the acquisition of substantially all of the assets of Devon including thermal in situ and heavy crude oil assets, for total cash purchase consideration of $3,412 million, subject to final closing adjustments.

In connection with the acquisition, the Company arranged a new $3,250 million committed term facility (see note 11) and assumed certain product transportation commitments (see note 20).

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

The following provides a summary of the net assets acquired relating to the acquisition:

Property, plant and equipment	**$**	**3,325**
Exploration and evaluation assets		**91**
Inventory, prepaids and other long-term assets		**195**
Accrued liabilities		**(21)**
Asset retirement obligations		**(178)**
Net assets acquired	**$**	**3,412**

The above amounts are estimates, and may be subject to change based on the receipt of new information.

As a result of the acquisition, revenue increased by approximately $1,540 million to $22,871 million and revenue, less production and transportation, blending and feedstock expenses increased by approximately $590 million to $11,895 million for the year ended December 31, 2019.

If the acquisition had been completed on January 1, 2019, the Company estimates that pro forma revenue, net of blending costs would have increased by an additional $1,010 million and pro forma revenue, net of blending costs, less production and transportation and feedstock expenses would have increased by an additional $670 million for the year ended December 31, 2019. Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have resulted had the acquisition actually occurred on January 1, 2019, or of future results. Pro forma results are based on available historical information for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition date.

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.

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. 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.

8. Leases

LEASE ASSETS

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At January 1, 2019 (1)	$ 823	$ 332	$ 252	$ 132	$ 1,539
Additions	**452**	**43**	**12**	**20**	**527**
Depreciation	**(106)**	**(54)**	**(72)**	**(27)**	**(259)**
Derecognitions	**—**	**(6)**	**—**	**—**	**(6)**
Foreign exchange adjustments and other	**(3)**	**2**	**(10)**	**(1)**	**(12)**
At December 31, 2019	**$ 1,166**	**$ 317**	**$ 182**	**$ 124**	**$ 1,789**

(1) The Company adopted IFRS 16 "Leases" on January 1, 2019 using the modified retrospective approach. At December 31, 2018, the Company did not report any finance leases in accordance with its previous accounting policy for leases.

LEASE ASSETS, BY SEGMENT

	Dec 31 2019
Exploration and Production	
North America	**$ 300**
North Sea	**38**
Offshore Africa	**154**
Oil Sands Mining and Upgrading	**1,191**
Head office	**106**
	$ 1,789

LEASE LIABILITIES

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities at December 31, 2019 were as follows:

	Dec 31 2019
Lease liabilities	**$ 1,809**
Less: current portion	**233**
	$ 1,576

In addition to the lease assets disclosed above, on an ongoing basis the Company enters into short-term leases related to its Exploration and Production and Oil Sands Mining and Upgrading activities.

Other amounts included in net earnings and cash flows during 2019 are provided below:

	Dec 31 2019
Expenses relating to short-term leases (1)	**$ 448**
Interest expense on lease liabilities	**$ 70**
Variable lease payments not included in the measurement of lease liabilities	**$ 118**
Total cash outflows for leases (2)	**$ 1,178**

(1) During 2019, the Company capitalized $305 million of short-term leases as additions to property, plant and equipment.
(2) Comprised of cash outflows relating to lease liabilities, short-term leases, and variable lease payments.

IMPACTS TO THE CONSOLIDATED FINANCIAL STATEMENTS ON TRANSITION

On transition to IFRS 16, the Company recognized $1,539 million of lease liabilities and corresponding lease assets. Lease liabilities were measured at the discounted value of lease payments using a weighted average incremental borrowing rate of 4.0% at January 1, 2019.

A reconciliation showing the impact of adoption of the standard is provided below:

		Jan 1 2019
Leases previously reported as commitments at December 31, 2018 (1) (2)	$	1,430
Impact of discounting		(317)
Leases previously reported as commitments, discounted at January 1, 2019		1,113
Leases recognized at adoption on January 1, 2019:		
Lease extension options and renewals reasonably certain to be exercised		243
Arrangements determined to be leases under IFRS 16		83
Leases entered into on behalf of a joint operation (3)		100
Lease liabilities recognized at January 1, 2019	$	1,539

(1) At December 31, 2018, the Company did not report any finance leases in accordance with its previous accounting policy for leases.

(2) Commitments for operating leases, previously reported in note 20, are now reported as part of lease liabilities and included in other long-term liabilities in note 12. Operating leases previously reported in note 20 have been aggregated into one line in the reconciliation table. Other non-lease commitments continue to be reported in the table in note 20.

(3) In accordance with the previous accounting for operating leases used in joint operations, the Company reported commitments and related expenses in accordance with the Company's proportionate interest in these joint operations. Under IFRS 16, where the Company acts as the operator of a joint operation, the Company recognizes 100% of the related lease asset and lease liability.

9. Investments

As at December 31, 2019 and 2018, the Company had the following investments:

		2019		2018
Investment in PrairieSky Royalty Ltd.	**$**	**345**	$	400
Investment in Inter Pipeline Ltd.		**145**		124
	$	**490**	$	524

INVESTMENT IN PRAIRIESKY ROYALTY LTD.

The Company's investment of 22.6 million common shares of PrairieSky Royalty Ltd. ("PrairieSky") does not constitute significant influence, and is accounted for at fair value through profit or loss, measured at each reporting date. As at December 31, 2019, the Company's investment in 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:

		2019		2018		2017
Fair value loss (gain) from PrairieSky	**$**	**55**	$	326	$	(3)
Dividend income from PrairieSky		**(17)**		(17)		(17)
	$	**38**	$	309	$	(20)

INVESTMENT IN INTER PIPELINE LTD.

The Company's investment of 6.4 million common shares of Inter Pipeline Ltd. ("Inter Pipeline") does not constitute significant influence, and is accounted for at fair value through profit or loss, measured at each reporting date. As at December 31, 2019, the Company's investment in Inter Pipeline was classified as a current asset. Inter Pipeline is in the business of oil sands transportation, natural gas liquids processing and conventional oil pipelines in Canada and bulk liquid storage in Europe.

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

		2019		2018		2017
Fair value (gain) loss from Inter Pipeline	**$**	**(21)**	$	43	$	23
Dividend income from Inter Pipeline		**(11)**		(11)		(10)
	$	**(32)**	$	32	$	13

10. Other Long-Term Assets

		2019		2018
North West Redwater Partnership subordinated debt (1)	$	**652**	$	591
Prepaid cost of service toll		**130**		62
Investment in North West Redwater Partnership		**—**		287
Risk management (note 19)		**290**		373
Long-term inventory		**121**		96
Other		**84**		50
		1,277		1,459
Less: current portion		**54**		116
	$	**1,223**	$	1,343

(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.

During 2018, Redwater Partnership commenced commissioning activities in the Project's light oil units while continuing work on the heavy oil units. In the first quarter of 2019, the light oil units transitioned from pre-commissioning and startup to operations and are processing synthetic crude oil into refined products. In December 2019, the light oil refinery completed activities relating to the planned maintenance shutdown. The Project continues to operate as a light oil refinery and will continue to process synthetic crude oil into refined products until the heavy oil units can reliably commence commercial processing of bitumen. As at December 31, 2019, the total estimate of capital costs incurred for the Project, net of margins from pre-commercial sales, was approximately $10 billion.

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. As at December 31, 2019, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $213 million, for a Company total of $652 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 tolls, 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 tolls over the 30-year tolling period. As at December 31, 2019, the Company had recognized $130 million in prepaid cost of service tolls (2018 – $62 million).

Redwater Partnership has a secured $3,500 million syndicated credit facility, of which $2,000 million is revolving and matures in June 2021 and the remaining $1,500 million is fully drawn on a non-revolving basis. During 2019, Redwater Partnership extended the $1,500 million non-revolving facility, previously scheduled to mature in February 2020, to February 2021. As at December 31, 2019, Redwater Partnership had borrowings of $2,715 million under the syndicated credit facility.

The assets, liabilities, partners' equity, product sales and equity loss related to Redwater Partnership and the Company's 50% interest at December 31, 2019 and 2018 were comprised as follows:

	2019		2018	
	Redwater Partnership 100% interest	**Company 50% interest**	Redwater Partnership 100% interest	Company 50% interest
Current assets	**$ 248**	**$ 124**	$ 210	$ 105
Non-current assets	**$ 11,328**	**$ 5,664**	$ 11,250	$ 5,625
Current liabilities	**$ 384**	**$ 192**	$ 352	$ 176
Non-current liabilities	**$ 11,310**	**$ 5,655**	$ 10,534	$ 5,267
Partners' equity	**$ (118)**	**$ (59)**	$ 574	$ 287
Product sales	**$ 1,736**	**$ 868**	$ —	$ —
Net loss	**$ 692**	**$ 346**	$ 10	$ 5

During 2019, the Company's interest in Redwater Partnership's net loss was $346 million (2018 – $5 million). Of this, the Company recognized an equity loss of $287 million, reducing the carrying value in Redwater Partnership to $ nil. The unrecognized share of losses for 2019 from Redwater Partnership was $59 million (2018 – $nil).

11. Long-Term Debt

		2019		2018
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**1,688**	$	831
Medium-term notes				
3.05% debentures due June 19, 2019		**—**		500
2.60% debentures due December 3, 2019		**—**		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
		5,988		6,131
US dollar denominated debt, unsecured				
Bank credit facilities (December 31, 2019 – US$3,745 million; December 31, 2018 – US$2,954 million)		**4,855**		4,031
Commercial paper (December 31, 2019 – US$254 million; December 31, 2018 – US$104 million)		**329**		141
US dollar debt securities				
3.45% due November 15, 2021 (US$500 million)		**648**		682
2.95% due January 15, 2023 (US$1,000 million)		**1,296**		1,364
3.80% due April 15, 2024 (US$500 million)		**648**		682
3.90% due February 1, 2025 (US$600 million)		**778**		819
3.85% due June 1, 2027 (US$1,250 million)		**1,621**		1,706
7.20% due January 15, 2032 (US$400 million)		**519**		546
6.45% due June 30, 2033 (US$350 million)		**454**		478
5.85% due February 1, 2035 (US$350 million)		**454**		478
6.50% due February 15, 2037 (US$450 million)		**583**		614
6.25% due March 15, 2038 (US$1,100 million)		**1,426**		1,501
6.75% due February 1, 2039 (US$400 million)		**519**		546
4.95% due June 1, 2047 (US$750 million)		**972**		1,023
		15,102		14,611
Long-term debt before transaction costs and original issue discounts, net		**21,090**		20,742
Less: original issue discounts, net (1)		**17**		17
transaction costs (1) (2)		**91**		102
		20,982		20,623
Less: current portion of commercial paper		**329**		141
current portion of other long-term debt (1) (2)		**2,062**		1,000
	$	**18,591**	$	19,482

(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, 2019, the Company had in place revolving bank credit facilities of $4,959 million of which $4,737 million was available for use. Additionally, the Company had in place fully drawn term credit facilities of $6,650 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 $750 million non-revolving term credit facility maturing February 2021;
- a $2,425 million revolving syndicated credit facility maturing June 2022;
- a $3,250 million non-revolving term credit facility maturing June 2022;
- a $2,650 million non-revolving term credit facility maturing February 2023;
- a $2,425 million revolving syndicated credit facility maturing June 2023; and
- a £5 million demand credit facility related to the Company's North Sea operations.

During 2019, the Company fully repaid and cancelled the $1,800 million non-revolving term credit facility scheduled to mature in May 2020. In addition, the $2,200 million non-revolving term credit facility, originally due October 2020, was extended to February 2023 and increased to $2,650 million.

During 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon (see note 7). The facility matures in June 2022 and is subject to annual amortization of 5% of the original balance.

Borrowings under the Company's non-revolving term credit 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. As at December 31, 2019, the non-revolving term credit facilities were fully drawn.

During 2019, the Company extended the $2,425 million revolving syndicated credit facility, of which $330 million was originally due June 2019 and $2,095 million was originally due June 2021, to June 2023. The revolving credit facilities are extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under the Company's revolving term credit 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 2019, the Company reduced the £15 million demand credit facility related to the Company's North Sea operations, to £5 million.

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 revolving 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, 2019 was 2.5% (December 31, 2018 – 2.6%), and on total long-term debt outstanding for the year ended December 31, 2019 was 4.0% (December 31, 2018 – 3.9%).

As at December 31, 2019, letters of credit and guarantees aggregating to $468 million were outstanding.

MEDIUM-TERM NOTES

During 2019, the Company repaid $500 million of 2.60% medium-term notes and $500 million of 3.05% medium-term notes.

In July 2019, 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 2021, replacing the Company's previous base shelf prospectus, which would have expired 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

In July 2019, 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 2021, replacing the Company's previous base shelf prospectus, which would have expired 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 2018, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

SCHEDULED DEBT REPAYMENTS

Scheduled debt repayments are as follows:

Year		Repayment
2020	$	2,391
2021	$	1,552
2022	$	3,879
2023	$	3,894
2024	$	1,148
Thereafter	$	8,226

12. Other Long-Term Liabilities

		2019		2018
Asset retirement obligations	$	**5,771**	$	3,886
Lease liabilities (note 8)		**1,809**		—
Share-based compensation		**297**		124
Risk management (note 19)		**112**		17
Deferred purchase consideration (1)		**95**		118
Other		**98**		80
		8,182		4,225
Less: current portion		**819**		335
	$	**7,363**	$	3,890

(1) Relates to the acquisition of the Joslyn oil sands project in 2018, payable in annual installments of $25 million over the next four years.

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 discounted using a weighted average discount rate of 3.8% (2018 – 5.0%; 2017 – 4.7%) and inflation rates of up to 2% (December 31, 2018 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

		2019		2018		2017
Balance – beginning of year	$	**3,886**	$	4,327	$	3,243
Liabilities incurred		**15**		19		12
Liabilities acquired, net		**198**		6		784
Liabilities settled		**(296)**		(290)		(274)
Asset retirement obligation accretion		**190**		186		164
Revision of cost, inflation rates and timing estimates		**412**		(111)		(40)
Change in discount rates		**1,412**		(334)		509
Foreign exchange adjustments		**(46)**		83		(71)
Balance – end of year		**5,771**		3,886		4,327
Less: current portion		**208**		186		92
	$	**5,563**	$	3,700	$	4,235

Segmented Asset Retirement Obligations

		2019		2018
Exploration and Production				
North America	$	**2,792**	$	1,665
North Sea		**816**		707
Offshore Africa		**161**		134
Oil Sands Mining and Upgrading		**2,000**		1,379
Midstream and Refining		**2**		1
	$	**5,771**	$	3,886

SHARE-BASED COMPENSATION

The liability for share-based compensation includes costs incurred under the Company's Stock Option Plan and PSU plans. The Company's Stock 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 PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met.

The Company recognizes a liability for potential cash settlements under these plans. The current portion of the liability represents the maximum amount of the liability payable within the next twelve month period if all vested stock options and PSUs are settled in cash.

		2019		2018		2017
Balance – beginning of year	**$**	**124**	$	414	$	426
Share-based compensation expense (recovery)		**223**		(146)		134
Cash payment for stock options surrendered		**(2)**		(5)		(6)
Transferred to common shares		**(53)**		(120)		(154)
Charged to (recovered from) Oil Sands Mining and Upgrading, net		**5**		(19)		14
Balance – end of year		**297**		124		414
Less: current portion		**227**		92		348
	$	**70**	$	32	$	66

Included within share-based compensation liability as at December 31, 2019 was $62 million (2018 – $13 million; 2017 – $5 million) related to PSUs granted to certain executive employees.

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

		2019		2018		2017
Fair value	**$**	**7.88**	$	3.33	$	11.82
Share price	**$**	**42.00**	$	32.94	$	44.92
Expected volatility		**26.7%**		27.4%		27.1%
Expected dividend yield		**3.6%**		4.1%		2.5%
Risk free interest rate		**1.7%**		1.9%		1.8%
Expected forfeiture rate		**4.3%**		4.2%		5.0%
Expected stock option life (1)		**4.4 years**		4.4 years		4.5 years

(1) At original time of grant.

The intrinsic value of vested stock options at December 31, 2019 was $75 million (2018 – $27 million; 2017 – $195 million).

13. Income Taxes

The provision for income tax was as follows:

Expense (recovery)		2019		2018		2017
Current corporate income tax – North America	**$**	**354**	$	312	$	(145)
Current corporate income tax – North Sea		**112**		28		57
Current corporate income tax – Offshore Africa		**44**		54		45
Current PRT (1) – North Sea		**(89)**		(29)		(132)
Other taxes		**13**		9		11
Current income tax		**434**		374		(164)
Deferred corporate income tax		**(895)**		540		586
Deferred PRT (1) – North Sea		**1**		17		54
Deferred income tax		**(894)**		557		640
Income tax	**$**	**(460)**	$	931	$	476

(1) Petroleum Revenue Tax.

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

		2019		2018		2017
Canadian statutory income tax rate		**26.5%**		27.0%		27.0%
Income tax provision at statutory rate	**$**	**1,313**	$	951	$	776
Effect on income taxes of:						
UK PRT and other taxes		**(76)**		(3)		(67)
Impact of deductible UK PRT and other taxes on corporate income tax		**32**		3		28
Foreign and domestic tax rate differentials		**(48)**		6		(43)
Non-taxable portion of capital (gains) losses		**(65)**		142		(86)
Stock options exercised for common shares		**47**		(41)		33
Income tax rate and other legislative changes		**(1,618)**		—		10
Non-taxable gain on corporate acquisitions		**—**		(119)		(63)
Revisions arising from prior year tax filings		**(41)**		(136)		(3)
Change in unrecognized capital loss carryforward asset		**(65)**		142		(86)
Other		**61**		(14)		(23)
Income tax (recovery) expense	**$**	**(460)**	$	931	$	476

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

		2019		2018
Deferred income tax liabilities				
Property, plant and equipment and exploration and evaluation assets	**$**	**12,074**	$	12,885
Lease assets		**412**		—
Unrealized risk management activities		**27**		33
PRT deduction for corporate income tax		**—**		1
Investments		**36**		46
Investment in North West Redwater Partnership		**593**		414
Other		**52**		179
		13,194		13,558
Deferred income tax assets				
Asset retirement obligations		**(1,488)**		(1,142)
Lease liabilities		**(416)**		—
Share-based compensation		**(16)**		(5)
Loss carryforwards		**(685)**		(855)
Unrealized foreign exchange loss on long-term debt		**(49)**		(104)
Deferred PRT		**(1)**		(1)
		(2,655)		(2,107)
Net deferred income tax liability	**$**	**10,539**	$	11,451

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

		2019		2018		2017
Property, plant and equipment and exploration and evaluation assets	**$**	**(775)**	$	281	$	541
Lease assets		**414**		—		—
Unrealized foreign exchange loss (gain) on long-term debt		**55**		(75)		120
Unrealized risk management activities		**(14)**		18		(46)
Asset retirement obligations		**(317)**		175		(88)
Lease liabilities		**(418)**		—		—
Share-based compensation		**(11)**		(5)		—
Loss carryforwards		**170**		(61)		48
Investments		**(10)**		(50)		(2)
Investment in North West Redwater Partnership		**179**		162		30
Deferred PRT		**1**		17		54
PRT deduction for corporate income tax		**—**		(7)		(21)
Other		**(168)**		102		4
	$	**(894)**	$	557	$	640

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

		2019		2018		2017
Balance – beginning of year	**$**	**11,451**	$	10,975	$	9,073
Deferred income tax (recovery) expense		**(894)**		557		640
Deferred income tax expense (recovery) included in other comprehensive income		**8**		(6)		4
Foreign exchange adjustments		**(26)**		41		(29)
Business combinations (note 6,7)		**—**		(116)		1,287
Balance – end of year	**$**	**10,539**	$	11,451	$	10,975

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 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by $1,618 million.

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.

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.

14. Share Capital

AUTHORIZED

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	2019		2018	
Issued Common shares	**Number of shares** (thousands)	**Amount**	Number of shares (thousands)	Amount
Balance – beginning of year	**1,201,886**	**$ 9,323**	1,222,769	$ 9,109
Issued upon exercise of stock options	**10,871**	**360**	9,975	332
Previously recognized liability on stock options exercised for common shares	**—**	**53**	—	120
Purchase of common shares under Normal Course Issuer Bid	**(25,900)**	**(203)**	(30,858)	(238)
Balance – end of year	**1,186,857**	**$ 9,533**	1,201,886	$ 9,323

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 4, 2020, the Board of Directors declared a quarterly dividend of $0.425 per common share, an increase from the previous quarterly dividend of $0.375 per common share, beginning with the dividend payable on April 1, 2020. 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. 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. On March 1, 2017, the Board of Directors declared a quarterly dividend of $0.275 per common share.

NORMAL COURSE ISSUER BID

On May 21, 2019, 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 59,729,706 common shares, over a 12-month period commencing May 23, 2019 and ending May 22, 2020. The Company's Normal Course Issuer Bid announced in May 2018 expired on May 22, 2019.

For the year ended December 31, 2019, the Company purchased 25,900,000 common shares at a weighted average price of $36.32 per common share for a total cost of $941 million. Retained earnings were reduced by $738 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2019, the Company purchased 6,970,000 common shares at a weighted average price of $38.84 per common share for a total cost of $271 million.

SHARE-BASED COMPENSATION – 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 7%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 7% of the common shares outstanding from time to time.

The following table summarizes information relating to stock options outstanding at December 31, 2019 and 2018:

	2019		2018	
	Stock options (thousands)	**Weighted average exercise price**	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	**46,685**	**$ 37.92**	56,036	$ 36.67
Granted	**16,314**	**$ 34.84**	4,256	$ 43.75
Surrendered for cash settlement	**(1,003)**	**$ 34.52**	(392)	$ 33.46
Exercised for common shares	**(10,871)**	**$ 33.16**	(9,975)	$ 33.28
Forfeited	**(3,479)**	**$ 37.65**	(3,240)	$ 38.76
Outstanding – end of year	**47,646**	**$ 38.04**	46,685	$ 37.92
Exercisable – end of year	**17,057**	**$ 38.74**	19,436	$ 36.03

The range of exercise prices of stock options outstanding and exercisable at December 31, 2019 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	2,361	1.03	$ 22.90	1,579	$ 22.90
$25.00 - $29.99	3,524	1.04	$ 28.85	2,236	$ 28.85
$30.00 - $34.99	5,174	4.97	$ 32.38	536	$ 32.58
$35.00 - $39.99	16,635	3.91	$ 36.85	2,263	$ 37.62
$40.00 - $44.99	16,117	2.24	$ 43.60	8,939	$ 43.58
$45.00 - $46.74	3,835	3.06	$ 45.20	1,504	$ 45.13
	47,646	3.04	$ 38.04	17,057	$ 38.74

15. Accumulated Other Comprehensive Income

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

	2019	2018
Derivative financial instruments designated as cash flow hedges	**$ 71**	$ 13
Foreign currency translation adjustment	**(37)**	109
	$ 34	$ 122

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, 2019, the ratio was within the target range at 37%.

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.

		2019		2018
Long-term debt, net (1)	**$**	**20,843**	$	20,522
Total shareholders' equity	**$**	**34,991**	$	31,974
Debt to book capitalization		**37%**		39%

(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, 2019, the Company was in compliance with this covenant.

17. Net Earnings Per Common Share

			2019		2018		2017
Weighted average common shares outstanding – basic (thousands of shares)			**1,190,977**		1,218,798		1,175,094
Effect of dilutive stock options (thousands of shares)			**2,129**		4,960		7,729
Weighted average common shares outstanding – diluted (thousands of shares)			**1,193,106**		1,223,758		1,182,823
Net earnings		**$**	**5,416**	$	2,591	$	2,397
Net earnings per common share	– basic	**$**	**4.55**	$	2.13	$	2.04
	– diluted	**$**	**4.54**	$	2.12	$	2.03

In 2019, the Company excluded 36,834,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share (year ended December 31, 2018 – 23,458,000; 2017 – 17,547,000).

18. Interest and Other Financing Expense

	2019	2018	2017
Interest and other financing expense:			
Long-term debt	**$ 895**	$ 867	$ 810
Lease liabilities (1)	**70**	—	—
Less: amounts capitalized on qualifying assets	**(53)**	(69)	(82)
Total interest and other financing expense	**912**	798	728
Total interest income	**(76)**	(59)	(97)
Net interest and other financing expense	**$ 836**	$ 739	$ 631

(1) The Company adopted IFRS 16 "Leases" on January 1, 2019 using the modified retrospective approach (see note 8).

19. Financial Instruments

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

	2019				
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	**$ 2,465**	**$ —**	**$ —**	**$ —**	**$ 2,465**
Investments	**—**	**490**	**—**	**—**	**490**
Other long-term assets	**652**	**—**	**290**	**—**	**942**
Accounts payable	**—**	**—**	**—**	**(816)**	**(816)**
Accrued liabilities	**—**	**—**	**—**	**(2,611)**	**(2,611)**
Other long-term liabilities (1)	**—**	**(21)**	**(91)**	**(1,904)**	**(2,016)**
Long-term debt (2)	**—**	**—**	**—**	**(20,982)**	**(20,982)**
	$ 3,117	**$ 469**	**$ 199**	**$ (26,313)**	**$ (22,528)**

	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)

(1) Includes $1,809 million of lease liabilities (December 31, 2018 – $nil) and $95 million of deferred purchase consideration payable over the nextfour years (December 31, 2018 – $118 million).
(2) Includes the current portion of long-term debt.

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

	2019			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3** (4) (5)
Investments (3)	**$ 490**	**$ 490**	**$ —**	**$ —**
Other long-term assets	**$ 942**	**$ —**	**$ 290**	**$ 652**
Other long-term liabilities	**$ (207)**	**$ —**	**$ (112)**	**$ (95)**
Fixed rate long-term debt (6) (7)	**$ (14,110)**	**$ (15,938)**	**$ —**	**$ —**

	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)	$ —	$ —

(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 payable).
(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 included in other long-term liabilities 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)	**2019**	2018
Derivatives held for trading		
Foreign currency forward contracts	**$ (10)**	$ 8
Natural gas AECO basis swaps	**(8)**	1
Natural gas AECO fixed price swaps	**(3)**	3
Crude oil WCS (1) differential swaps	**—**	(17)
Cash flow hedges		
Foreign currency forward contracts	**(91)**	70
Cross currency swaps	**290**	291
	$ 178	$ 356
Included within:		
Current portion of other long-term assets	**$ 8**	$ 92
Current portion of other long-term liabilities	**(112)**	(17)
Other long-term assets	**282**	281
	$ 178	$ 356

(1) Western Canadian Select.

During 2019, the Company recognized a gain of $3 million (2018 – gain of $2 million, 2017 – gain of $5 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair values 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 interest rate yield curves, and Canadian and United States forward 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)		**2019**		2018
Balance – beginning of year	**$**	**356**	$	101
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**(13)**		35
Foreign exchange		**(231)**		260
Other comprehensive income (loss)		**66**		(40)
Balance – end of year		**178**		356
Less: current portion		**(104)**		75
	$	**282**	$	281

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

		2019		2018		2017
Net realized risk management loss (gain)	**$**	**64**	$	(99)	$	(2)
Net unrealized risk management loss (gain)		**13**		(35)		37
	$	**77**	$	(134)	$	35

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, 2019, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

	Remaining term		**Volume**	**Weighted average price**	**Index**
Natural Gas					
AECO basis swaps	Jan 2020 –	Mar 2020	140,000 MMbtu/d	US$0.93	NYMEX
AECO fixed price swaps	Apr 2020 –	Oct 2020	102,500 GJ/d	$1.51	AECO

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, 2019, the Company had no interest rate swap contracts outstanding.

FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

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

At December 31, 2019 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 2020	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2020	–	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at December 31, 2019 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2019, the Company had US$4,564 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$3,999 million designated as cash flow hedges.

FINANCIAL INSTRUMENT SENSITIVITIES

The following table summarizes the annualized sensitivities of the Company's 2019 net earnings and other comprehensive income (loss) to changes in the fair value of financial instruments outstanding as at December 31, 2019, 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.

	2019		2018	
	Increase (decrease) to net earnings	**(Increase) decrease to other comprehensive loss**	Increase (decrease) to net earnings	Increase (decrease) to other comprehensive income
Commodity price risk				
Increase NYMEX/AECO basis US$0.10 MMBtu	**$ 1**	**$ —**	$ —	$ —
Decrease NYMEX/AECO basis US$0.10 MMBtu	**$ (1)**	**$ —**	$ —	$ —
Increase AECO $0.10/Mcf (1)	**$ (1)**	**$ —**	$ (1)	$ —
Decrease AECO $0.10/Mcf (1)	**$ 1**	**$ —**	$ 1	$ —
Increase WCS differential US$1.00/bbl	**$ —**	**$ —**	$ (5)	$ —
Decrease WCS differential US$1.00/bbl	**$ —**	**$ —**	$ 5	$ —
Interest rate risk				
Increase interest rate 1%	**$ (48)**	**$ (21)**	$ (33)	$ (21)
Decrease interest rate 1%	**$ 48**	**$ 24**	$ 33	$ 25
Foreign currency exchange rate risk				
Weakening of the Canadian dollar by US$0.01	**$ (103)**	**$ —**	$ (114)	$ —
Strengthening of the Canadian dollar by US$0.01	**$ 100**	**$ —**	$ 113	$ —

(1) Movements in AECO are based on the Company's contracted AECO fixed price swap volumes at December 31, 2019 and 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, 2019, 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 (December 31, 2018 – 1%).

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, 2019, the Company had net risk management assets of $265 million with specific counterparties related to derivative financial instruments (December 31, 2018 – $361 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	$ 816	$ —	$ —	$ —
Accrued liabilities	$ 2,611	$ —	$ —	$ —
Long-term debt (1)	$ 2,391	$ 1,552	$ 8,921	$ 8,226
Other long-term liabilities (2)	$ 370	$ 196	$ 436	$ 1,014
Interest and other financing expense (3)	$ 881	$ 813	$ 1,771	$ 4,856

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.
(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, $233 million; one to less than two years, $171 million; two to less than five years, $391 million; and thereafter $1,014 million.
(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates at December 31, 2019.

20. Commitments and Contingencies

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2019 (1):

	2020	2021	2022	2023	2024	Thereafter
Product transportation (2) (3)	$ 730	$ 722	$ 637	$ 726	$ 699	$ 7,907
North West Redwater Partnership service toll (4)	$ 133	$ 167	$ 157	$ 164	$ 156	$ 2,815
Offshore vessels and equipment	$ 69	$ 63	$ 9	$ —	$ —	$ —
Field equipment and power	$ 27	$ 21	$ 20	$ 21	$ 20	$ 249
Other	$ 26	$ 20	$ 17	$ 17	$ 17	$ 30

(1) Subsequent to the adoption of IFRS 16, the Company reports its payments for lease liabilities in the maturity table in note 19.
(2) On June 27, 2019, the Company assumed $2,381 million of product transportation commitments related to the acquisition of assets from Devon.
(3) Includes commitments pertaining to a 20 year product transportation agreement on the Trans Mountain Pipeline Expansion. In addition, the Company has entered into certain product transportation agreements on pipelines that have not yet received regulatory and other approvals. The Company may be required to reimburse certain construction costs to the service provider under certain conditions.
(4) 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 tolls, which currently consists of interest and fees, with principal repayments beginning in 2020. Included in the cost of service tolls is $1,260 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

	2019	2018	2017
Changes in non-cash working capital			
Accounts receivable	**$ (1,310)**	$ 1,233	$ (977)
Current income tax (liabilities) assets	**(164)**	471	527
Inventory	**(194)**	(74)	81
Prepaids and other	**2**	(3)	(28)
Other long-term assets	**117**	—	—
Accounts payable	**39**	(7)	175
Accrued liabilities	**265**	(268)	365
Other long-term liabilities (1) (2)	**(23)**	(351)	469
Net changes in non-cash working capital	**$ (1,268)**	$ 1,001	$ 612
Relating to:			
Operating activities	**$ (1,033)**	$ 1,346	$ 299
Investing activities	**(235)**	(345)	313
	$ (1,268)	$ 1,001	$ 612

	2019	2018	2017
Expenditures on exploration and evaluation assets	**$ 73**	$ 282	$ 159
Net proceeds on sale of exploration and evaluation assets	**—**	(16)	(35)
Net expenditures on exploration and evaluation assets	**$ 73**	$ 266	$ 124

(1) Included in other long-term liabilities at December 31, 2019 is $95 million of deferred purchase consideration payable over the next four years (December 31, 2018 – $118 million).
(2) Included in other long-term liabilities at December 31, 2017 is $469 million (US$375 million) of deferred purchase consideration paid to Marathon.

The following table summarizes movements in the Company's liabilities arising from financing activities for the years' ended December 31, 2019 and 2018:

	Long-term debt	Cash flow hedges on US dollar debt securities	Lease liabilities	Liabilities from financing activities
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
Adoption of IFRS 16 (3)	—	—	1,539	1,539
At January 1, 2019	20,623	(361)	1,539	21,801
Changes from financing cash flows:				
Issue of long-term debt, net (1)	**1,025**	**—**	**—**	**1,025**
Payment of lease liabilities	**—**	**—**	**(237)**	**(237)**
Non-cash changes:				
Lease additions	**—**	**—**	**527**	**527**
Changes in foreign exchange and fair value (2)	**(666)**	**162**	**(20)**	**(524)**
At December 31, 2019	**$ 20,982**	**$ (199)**	**$ 1,809**	**$ 22,592**

(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, the amortization of original issue discounts and premiums and directly attributable transaction costs, and derecognitions of lease liabilities.
(3) The Company adopted IFRS 16 "Leases" on January 1, 2019 using the modified retrospective approach (see note 2).

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 and Refining 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)	**2019**	2018	2017	**2019**	2018	2017	**2019**	2018	2017
Segmented product sales									
Crude oil and NGLs (1)	**$ 9,679**	$ 7,254	$ 7,655	**$ 860**	$ 753	$ 666	**$ 632**	$ 628	$ 579
Natural gas	**1,150**	1,256	1,506	**57**	140	118	**67**	70	53
Other (2)	**6**	—	—	**5**	—	—	**8**	—	—
Total segmented product sales	**10,835**	8,510	9,161	**922**	893	784	**707**	698	632
Less: royalties	**(998)**	(723)	(809)	**(2)**	(2)	(1)	**(42)**	(51)	(41)
Segmented revenue	**9,837**	7,787	8,352	**920**	891	783	**665**	647	591
Segmented expenses									
Production	**2,425**	2,405	2,362	**391**	405	400	**109**	208	226
Transportation, blending and feedstock (1)	**2,935**	2,587	2,291	**19**	22	31	**2**	2	1
Depletion, depreciation and amortization	**3,326**	3,132	3,243	**308**	257	509	**242**	201	205
Asset retirement obligation accretion	**95**	87	80	**28**	29	27	**6**	9	9
Realized risk management (commodity derivatives)	**49**	(10)	(45)	**—**	—	—	**—**	—	—
Gain on acquisition, disposition and revaluation of properties	**—**	(277)	(35)	**—**	(139)	—	**—**	(36)	—
Equity loss (gain) from investments	**—**	—	—	**—**	—	—	**—**	—	—
Total segmented expenses	**8,830**	7,924	7,896	**746**	574	967	**359**	384	441
Segmented earnings (loss) before the following	**$ 1,007**	$ (137)	$ 456	**$ 174**	$ 317	$ (184)	**$ 306**	$ 263	$ 150
Non–segmented expenses									
Administration									
Share-based compensation									
Interest and other financing expense									
Risk management activities (other)									
Foreign exchange (gain) loss									
Loss (gain) from investments									
Total non–segmented expenses									
Earnings before taxes									
Current income tax expense (recovery)									
Deferred income tax (recovery) expense									
Net earnings									

(1) Includes blending and feedstock costs associated with the processing of third party bitumen and other purchased feedstock in the Oil Sands Mining and Upgrading segment

(2) 'Other' includes recoveries associated with the joint operation partners' share of the costs of lease contracts and other income of a trivial nature.

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, 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 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 and Refining			Inter–segment elimination and Other			Total		
	2019	2018	2017	**2019**	2018	2017	**2019**	2018	2017	**2019**	2018	2017
$	**11,340**	$ 11,521	$ 7,072	**$**	**88**	$ 102	$ 102	**$**	**351**	$ 410	$ 448	**$ 22,950**	$ 20,668	$ 16,522
	—	—	—		**—**	—	—		**145**	148	161	**1,419**	1,614	1,838
	6	—	—		**—**	—	—		**—**	—	—	**25**	—	—
	11,346	11,521	7,072		**88**	102	102		**496**	558	609	**24,394**	22,282	18,360
	(481)	(479)	(167)		**—**	—	—		**—**	—	—	**(1,523)**	(1,255)	(1,018)
	10,865	11,042	6,905		**88**	102	102		**496**	558	609	**22,871**	21,027	17,342
	3,276	3,367	2,600		**20**	21	16		**56**	58	71	**6,277**	6,464	5,675
	1,306	1,087	679		**—**	—	—		**437**	491	527	**4,699**	4,189	3,529
	1,656	1,557	1,220		**14**	14	9		**—**	—	—	**5,546**	5,161	5,186
	61	61	48		**—**	—	—		**—**	—	—	**190**	186	164
	—	—	—		**—**	—	—		**—**	—	—	**49**	(10)	(45)
	—	—	(230)		**—**	—	(114)		**—**	—	—	**—**	(452)	(379)
	—	—	—		**287**	5	(31)		**—**	—	—	**287**	5	(31)
	6,299	6,072	4,317		**321**	40	(120)		**493**	549	598	**17,048**	15,543	14,099
$	**4,566**	$ 4,970	$ 2,588	**$**	**(233)**	$ 62	$ 222	**$**	**3**	$ 9	$ 11	**$ 5,823**	$ 5,484	$ 3,243
												344	325	319
												223	(146)	134
												836	739	631
												28	(124)	80
												(570)	827	(787)
												6	341	(7)
												867	1,962	370
												4,956	3,522	2,873
												434	374	(164)
												(894)	557	640
												$ 5,416	$ 2,591	$ 2,397

(1) Includes blending and feedstock costs associated with the processing of third party bitumen and other purchased feedstock in the Oil Sands Mining and Upgrading segment

(2) 'Other' includes recoveries associated with the joint operation partners' share of the costs of lease contracts and other income of a trivial nature.

CAPITAL EXPENDITURES (1)

	2019			2018		
	Net expenditures	**Non-cash and fair value changes (2)**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes (2)	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America (3)	**$ 129**	**$ (219)**	**$ (90)**	$ 118	$ (52)	$ 66
North Sea	**—**	**—**	**—**	—	—	—
Offshore Africa (4)	**35**	**(2)**	**33**	(54)	—	(54)
Oil Sands Mining and Upgrading (5)	**—**	**—**	**—**	218	(225)	(7)
	$ 164	**$ (221)**	**$ (57)**	$ 282	$ (277)	$ 5
Property, plant and equipment						
Exploration and Production						
North America (3)	**$ 4,702**	**$ 918**	**$ 5,620**	$ 2,553	$ (362)	$ 2,191
North Sea	**196**	**153**	**349**	131	(597)	(466)
Offshore Africa (6)	**194**	**(1,476)**	**(1,282)**	228	(86)	142
	5,092	**(405)**	**4,687**	2,912	(1,045)	1,867
Oil Sands Mining and Upgrading (7)	**1,525**	**344**	**1,869**	1,229	(166)	1,063
Midstream and Refining	**10**	**—**	**10**	13	—	13
Head office	**34**	**(3)**	**31**	21	—	21
	$ 6,661	**$ (64)**	**$ 6,597**	$ 4,175	$ (1,211)	$ 2,964

(1) This table provides a reconciliation of capitalized costs, reported in note 6 and note 7, to net expenditures reported in the investing activities section of the statements of cash flows. The reconciliation excludes the impact of foreign exchange adjustments.
(2) Derecognitions, asset retirement obligations, transfer of exploration and evaluation assets, and other fair value adjustments.
(3) Includes cash consideration paid of $91 million for exploration and evaluation assets and $3,126 million for property, plant and equipment acquired from Devon in 2019.
(4) Excludes the impact of a pre-tax cash gain of $16 million on the disposition of certain exploration and evaluation assets in 2018.
(5) In 2018, total purchase consideration for the acquisition of the Joslyn oil sands project included $222 million for exploration and evaluation assets and $4 million for asset retirement obligations assumed. In addition, 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.
(6) Includes a derecognition of property, plant and equipment of $1,515 million following the FPSO demobilization at the Olowi field, Gabon in 2019.
(7) Net expenditures include capitalized interest and share-based compensation.

SEGMENTED ASSETS

	2019	2018
Exploration and Production		
North America	**$ 30,963**	$ 27,199
North Sea	**1,948**	1,699
Offshore Africa	**1,529**	1,471
Other	**30**	33
Oil Sands Mining and Upgrading	**42,006**	39,634
Midstream and Refining	**1,418**	1,413
Head office	**227**	110
	$ 78,121	$ 71,559

23. Remuneration of Directors and Senior Management

Remuneration of Non-Management Directors

		2019		2018		2017
Fees earned	**$**	**2**	$	2	$	3

Remuneration of Senior Management (1)

		2019		2018		2017
Salary	**$**	**2**	$	2	$	3
Common stock option based awards		**8**		8		10
Annual incentive plans		**6**		4		5
Long-term incentive plans		**20**		15		17
	$	**36**	$	29	$	35

(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.

24. Events Subsequent to December 31, 2019

Subsequent to December 31, 2019, crude oil benchmark prices decreased substantially due to a drop in global crude oil demand triggered by the impact of the COVID-19 virus on the global economy. In March 2020, crude oil prices decreased further due to a breakdown in negotiations between OPEC and non-OPEC partners regarding proposed production cuts. The recent volatility in the crude oil pricing environment may continue and could impact the Company's earnings and cash flows.



Canadian Natural Resources Limited

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2019

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
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
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
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
FASB	Financial Accounting Standards Board
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
OPEC	Organization of the Petroleum Exporting Countries
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", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration" 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, without limitation, those in relation to the Company's assets at Horizon, AOSP, Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the Jackfish Thermal Oil Sands Project, the timing 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 2020 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 earlier 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 (including as a result of demand and supply effects resulting from the COVID-19 virus pandemic and the actions of OPEC and non-OPEC countries) 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; 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 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, maintain and operate 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 (including production curtailments mandated by the Government of Alberta); 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, state 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 in this MD&A, 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 from operations; adjusted funds flow (previously referred to as funds flow from operations) and net capital expenditures. 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, 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 from operations is reconciled to net earnings, 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 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 for the year ended December 31, 2019. It should also be read in conjunction with the Company's MD&A for the three months and year ended December 31, 2019, 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"). Changes in the Company's accounting policies in accordance with IFRS, including the adoption of IFRS 16 "Leases" on January 1, 2019, are discussed in the "Changes in Accounting Policies" section of this MD&A. In accordance with the new IFRS 16 "Leases" standard, comparative balances in 2018 reported in this MD&A have not been restated.

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 in this MD&A for information purposes only.

The following discussion and analysis refers primarily to the Company's 2019 financial results compared to 2018 and 2017, unless otherwise indicated. In addition, this MD&A details the Company's targeted capital program for 2020. Additional information relating to the Company, including its quarterly MD&A for the three months and year ended December 31, 2019, its Annual Information Form for the year ended December 31, 2019, and its audited consolidated financial statements for the year ended December 31, 2019, 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. Information on the Company's website, including such guidance, does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated March 18, 2020.

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 and sustainable 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 in a sustainable and responsible way, maintaining a commitment to environmental stewardship and safety excellence.

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;
- Balance between sources and terms of debt financing and a strong financial position; and
- Commitment to environmental stewardship throughout the decision-making process.

(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 and embraces the key piece of the Company's mission statement: "doing it right". 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. The Company's financial discipline, commitment to a strong balance sheet, and capacity to internally generate cash flows provides the means to responsibly and sustainably grow in the long term.

Financial and Operational Highlights

($ millions, except per common share amounts)		2019		2018		2017
Product sales (1)	$	**24,394**	$	22,282	$	18,360
Crude oil and NGLs	$	**22,950**	$	20,668	$	16,522
Natural gas	$	**1,419**	$	1,614	$	1,838
Net earnings	$	**5,416**	$	2,591	$	2,397
Per common share – basic	$	**4.55**	$	2.13	$	2.04
– diluted	$	**4.54**	$	2.12	$	2.03
Adjusted net earnings from operations (2)	$	**3,795**	$	3,263	$	1,403
Per common share – basic	$	**3.19**	$	2.68	$	1.19
– diluted	$	**3.18**	$	2.67	$	1.19
Cash flows from operating activities	$	**8,829**	$	10,121	$	7,262
Adjusted funds flow (3)	$	**10,267**	$	9,088	$	7,347
Per common share – basic	$	**8.62**	$	7.46	$	6.25
– diluted	$	**8.61**	$	7.43	$	6.21
Dividends declared per common share (4)	$	**1.50**	$	1.34	$	1.10
Total assets	$	**78,121**	$	71,559	$	73,867
Total long-term liabilities	$	**36,493**	$	34,823	$	35,953
Cash flows used in investing activities	$	**7,255**	$	4,814	$	13,102
Net capital expenditures (5)	$	**7,121**	$	4,731	$	17,129
Average sales price (6)						
Crude oil and NGLs - Exploration and Production ($/bbl)	$	**55.08**	$	46.92	$	48.57
Natural gas - Exploration and Production ($/Mcf)	$	**2.34**	$	2.61	$	2.76
Oil Sands Mining and Upgrading ($/bbl)	$	**70.18**	$	68.61	$	63.98
Daily production, before royalties (BOE/d)		**1,098,957**		1,078,813		962,264
Crude oil and NGLs (bbl/d)		**850,393**		820,778		685,236
Natural gas (MMcf/d)		**1,491**		1,548		1,662

(1) Further details related to product sales, including 'Other' income for 2019 are disclosed in note 22 to the Company's audited consolidated financial statements.

(2) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings as presented in the Company's consolidated Statements of Earnings, adjusted for the after-tax effects of certain items of a non-operational nature. The Company considers adjusted net earnings from operations a key measure in evaluating its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. The reconciliation "Adjusted Net Earnings from Operations, as Reconciled to Net Earnings" is presented in this MD&A. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(3) 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 expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls. The Company considers adjusted funds flow a key measure in evaluating its performance 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.

(4) On March 4, 2020, the Board of Directors approved an increase in the quarterly dividend to $0.425 per common share, beginning with the dividend payable on April 1, 2020. 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.

(5) 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 combinations 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.

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

ADJUSTED NET EARNINGS FROM OPERATIONS, AS RECONCILED TO NET EARNINGS

($ millions)		**2019**		2018		2017
Net earnings, as reported	**$**	**5,416**	$	2,591	$	2,397
Share-based compensation, net of tax (1)		**210**		(146)		134
Unrealized risk management loss (gain), net of tax (2)		**14**		(36)		33
Unrealized foreign exchange (gain) loss, net of tax (3)		**(548)**		706		(821)
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)		**321**		374		(11)
Gain on acquisition, disposition and revaluation of properties, net of tax (7)		**—**		(372)		(339)
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (8)		**(1,618)**		—		10
Adjusted net earnings from operations	**$**	**3,795**	$	3,263	$	1,403

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("PSU") plans. The Company's employee stock option plan provides for a cash payment option. The PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met. Accordingly, the fair value of the compensation under these plans is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings or are 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. 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.

(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 equity loss (gain) recognized.

(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.

(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.

(8) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to the underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. During 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by $1,618 million. 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.

ADJUSTED FUNDS FLOW, AS RECONCILED TO CASH FLOWS FROM OPERATING ACTIVITIES (1)

($ millions)	**2019**	2018	2017
Cash flows from operating activities	**$ 8,829**	$ 10,121	$ 7,262
Net change in non-cash working capital	**1,033**	(1,346)	(299)
Abandonment expenditures (2)	**296**	290	274
Other (3)	**109**	23	110
Adjusted funds flow	**$ 10,267**	$ 9,088	$ 7,347

(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) Movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

CONSOLIDATED NET EARNINGS AND ADJUSTED NET EARNINGS

For 2019, the Company reported net earnings of $5,416 million compared with $2,591 million for 2018 (2017 – $2,397 million). Net earnings for 2019 included net after-tax income of $1,621 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 from investments, gain on acquisition, disposition and revaluation of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities (2018 – $672 million after-tax income; 2017 – $994 million after-tax income). Excluding these items, adjusted net earnings from operations for 2019 were $3,795 million compared with $3,263 million for 2018 (2017 – $1,403 million).

The increase in net earnings and adjusted net earnings from operations for 2019 from 2018 was primarily due to:

- higher crude oil and NGLs sales volumes and netbacks in the Exploration and Production segments; and
- higher realized foreign exchange gains;

partially offset by:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower natural gas netbacks in the Exploration and Production segments; and
- higher realized risk management losses.

Net earnings for 2019 as compared to net earnings for 2018 also reflected the Government of Alberta enacted decrease in the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. This resulted in a decrease in the Company's deferred corporate income tax liability of $1,618 million. See the "Income Taxes" 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 for 2019 from 2018. For 2019, the adoption of IFRS 16 did not have a significant overall impact on net earnings or adjusted net earnings from operations. These items are discussed in detail in the relevant sections of this MD&A.

Subsequent to December 31, 2019, crude oil benchmark prices decreased substantially due to a drop in global crude oil demand triggered by the impact of the COVID-19 virus on the global economy. In March 2020, crude oil prices decreased further due to a breakdown in negotiations between OPEC and non-OPEC partners regarding proposed production cuts. The volatility in the crude oil pricing environment could impact the Company’s earnings and cash flows.

CASH FLOWS FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW

Cash flows from operating activities for 2019 decreased to $8,829 million from $10,121 million for 2018 (2017 – $7,262 million). The decrease in cash flows from operating activities for 2019 from 2018 was primarily due to the impact of changes in non-cash working capital, primarily due to an increase in accounts receivable from 2018. Cash flows from operating activities was further impacted by factors previously noted relating to the fluctuations in net earnings and adjusted net earnings from operations (except for the effect of depletion, depreciation and amortization).

Adjusted funds flow for 2019 increased to $10,267 million ($8.62 per common share) from $9,088 million for 2018 ($7.46 per common share) (2017 – $7,347 million; $6.25 per common share). The increase in adjusted funds flow for 2019 from 2018 was primarily due to the factors previously noted relating to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

Cash flows from operating activities and adjusted funds flow for 2019 reflected an increase of $237 million related to the adoption of IFRS 16 on January 1, 2019 as the principal portions of lease payments previously classified as cash

flows from operating activities are now reported as cash flows used in financing activities. The adoption of IFRS 16 is discussed in the "Changes in Accounting Policies" section of this MD&A.

PRODUCT PRICING

In the Company's Exploration and Production activities, the 2019 average sales price per barrel of crude oil and NGLs increased 17% to average $55.08 per bbl from $46.92 per bbl in 2018 (2017 – $48.57 per bbl), and the 2019 average natural gas price decreased 10% to average $2.34 per Mcf from $2.61 per Mcf in 2018 (2017 – $2.76 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2019 average SCO sales price of $70.18 per bbl compared with $68.61 per bbl in 2018 (2017 – $63.98 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 2019 increased 4% to average 850,393 bbl/d from 820,778 bbl/d in 2018 (2017 – 685,236 bbl/d). The increase in crude oil and NGLs production from 2018 primarily reflected production from the acquisition of thermal and heavy oil assets from Devon Canada Corporation ("Devon"), offsetting the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. The Company continues to optimize its production volumes across the asset base during curtailment.

Total natural gas production before royalties for 2019 decreased 4% to average 1,491 MMcf/d from 1,548 MMcf/d in 2018 (2017 – 1,662 MMcf/d). The decrease in natural gas production from 2018 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities due to low natural gas prices.

Total production volumes before royalties for 2019 of 1,098,957 BOE/d was comparable with 1,078,813 BOE/d in 2018 (2017 – 962,264 BOE/d). Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

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)

2019	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales (1)	$ 24,394	$ 6,335	$ 6,587	$ 5,931	$ 5,541
Crude oil and NGLs	$ 22,950	$ 5,947	$ 6,324	$ 5,597	$ 5,082
Natural gas	$ 1,419	$ 382	$ 257	$ 324	$ 456
Net earnings (loss)	$ 5,416	$ 597	$ 1,027	$ 2,831	$ 961
Net earnings (loss) per common share					
– basic	$ 4.55	$ 0.50	$ 0.87	$ 2.37	$ 0.80
– diluted	$ 4.54	$ 0.50	$ 0.87	$ 2.36	$ 0.80

($ 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

(1) Further details related to product sales, including 'Other' income for 2019 are disclosed in note 22 to the Company's audited consolidated financial statements.

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 OPEC and its impact on world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the WCS Heavy Differential from the WTI 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 Brent benchmark pricing in the North Sea and Offshore Africa and the impact of production curtailments mandated by the Government of Alberta that came into effect on January 1, 2019.
- **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 and Kirby North, the results from the Pelican Lake water and polymer flood projects, fluctuations in the Company's drilling program in North America and the International segments, the impact and timing of acquisitions, including the acquisition of assets from Devon, 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 in late 2018 due to low commodity prices in North America and production curtailments mandated by the Government of Alberta that came into effect January 1, 2019. 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 the Pine River 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, the impact of increased carbon tax and energy costs, cost optimizations across all segments, the impact and timing of acquisitions, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, maintenance activities in the International segments and the impact of the adoption of IFRS 16 on January 1, 2019.
- **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, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment and the impact of the adoption of IFRS 16 on January 1, 2019.

- **Share-based compensation –** Fluctuations due to the measurement of fair market value 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.
- **Interest expense –** Fluctuations due to the adoption of IFRS 16 on January 1, 2019, fluctuating long-term debt levels, and the impact of movements in benchmark interest rates on outstanding floating rate long-term debt.
- **Foreign exchange rates –** Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company receives 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.
- **Gains on acquisition, disposition and revaluation of properties and gains/losses on investments –** Fluctuations due to the recognition of 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 on the Company's interest in the Redwater Partnership.
- **Income tax expense –** Fluctuations in income tax expense due to statutory tax rate and other legislative changes substantively enacted in the various periods.

Business Environment

(Yearly average)		**2019**		2018		2017
WTI benchmark price (US$/bbl)	**$**	**57.04**	$	64.78	$	50.93
Dated Brent benchmark price (US$/bbl)	**$**	**64.04**	$	71.12	$	54.38
WCS Heavy Differential from WTI (US$/bbl)	**$**	**12.79**	$	26.29	$	11.97
SCO price (US$/bbl)	**$**	**56.35**	$	58.62	$	52.20
Condensate benchmark price (US$/bbl)	**$**	**52.84**	$	60.98	$	51.65
Condensate Differential from WTI (US$/bbl)	**$**	**4.20**	$	3.80	$	(0.72)
NYMEX benchmark price (US$/MMBtu)	**$**	**2.63**	$	3.08	$	3.11
AECO benchmark price (C$/GJ)	**$**	**1.54**	$	1.45	$	2.30
US/Canadian dollar average exchange rate (US$)	**$**	**0.7536**	$	0.7717	$	0.7701
US/Canadian dollar year end exchange rate (US$)	**$**	**0.7713**	$	0.7328	$	0.7988

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 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. Product revenue continued to be impacted by the volatility of 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.

Effective January 1, 2019, the Government of Alberta implemented a mandatory curtailment program that has been successful in mitigating the discount in crude oil pricing received in Alberta for both light crude oil and heavy crude oil. The timing of program cessation remains uncertain. The Company continues to execute operational flexibility to maximize production volumes through its curtailment optimization strategy, and has significant additional capacity available to further increase production volumes should curtailment restrictions ease.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US $57.04 per bbl for 2019, a decrease of 12% from US$64.78 per bbl for 2018 (2017 – US$50.93 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$64.04 per bbl for 2019, a decrease of 10% from US$71.12 per bbl for 2018 (2017 – US$54.38 per bbl).

WTI and Brent pricing for 2019 decreased from 2018 primarily due to increases in non-OPEC crude oil supply. In addition, global crude oil pricing has been impacted by ongoing trade disputes between the US and China.

The WCS Heavy Differential averaged US$12.79 per bbl for 2019, a decrease of 51% from US$26.29 per bbl for 2018 (2017 – US$11.97 per bbl). The narrowing of the WCS Heavy Differential reflected the impact of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019.

The SCO price averaged US$56.35 per bbl for 2019, a decrease of 4% from US$58.62 per bbl for 2018 (2017 – US$52.20 per bbl). The decrease in SCO pricing for 2019 from 2018 primarily reflected decreases in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.63 per MMBtu for 2019, a decrease of 15% from US$3.08 per MMBtu for 2018 (2017 – US$3.11 per MMBtu). The decrease in NYMEX natural gas prices for 2019 from 2018 primarily reflected increased production levels in North America and the impact of seasonal weather conditions.

AECO natural gas prices averaged $1.54 per GJ for 2019, an increase of 6% from $1.45 per GJ for 2018 (2017 – $2.30 per GJ). The increase in AECO natural gas prices for 2019 from 2018 primarily reflected additional egress capability and the impact of the TC Energy Temporary Service Protocol.

Analysis of Changes in Product Sales

		Changes due to				**Changes due to**			
($ millions)	2017	Volumes	Prices	Other	2018	**Volumes**	**Prices**	**Other**	**2019**
North America									
Crude oil and NGLs	$ 7,655	$ (188)	$ (224)	$ 11	$ 7,254	**$ 1,055**	**$ 1,375**	**$ (5)**	**$ 9,679**
Natural gas	1,506	(105)	(136)	(9)	1,256	**(40)**	**(76)**	**10**	**1,150**
Other	—	—	—	—	—	**—**	**—**	**6**	**6**
	9,161	(293)	(360)	2	8,510	**1,015**	**1,299**	**11**	**10,835**
North Sea									
Crude oil and NGLs	666	(69)	155	1	753	**114**	**(7)**	**—**	**860**
Natural gas	118	(23)	45	—	140	**(34)**	**(49)**	**—**	**57**
Other	—	—	—	—	—	**—**	**—**	**5**	**5**
	784	(92)	200	1	893	**80**	**(56)**	**5**	**922**
Offshore Africa									
Crude oil and NGLs	579	(102)	164	(13)	628	**72**	**(56)**	**(12)**	**632**
Natural gas	53	10	7	—	70	**(5)**	**1**	**1**	**67**
Other	—	—	—	—	—	**—**	**—**	**8**	**8**
	632	(92)	171	(13)	698	**67**	**(55)**	**(3)**	**707**
Total Exploration and Production									
Crude oil and NGLs	8,900	(359)	95	(1)	8,635	**1,241**	**1,312**	**(17)**	**11,171**
Natural gas	1,677	(118)	(84)	(9)	1,466	**(79)**	**(124)**	**11**	**1,274**
Other	—	—	—	—	—	**—**	**—**	**19**	**19**
	10,577	(477)	11	(10)	10,101	**1,162**	**1,188**	**13**	**12,464**
Oil Sands Mining and Upgrading									
Crude oil and NGLs	7,072	3,696	722	31	11,521	**(710)**	**560**	**(31)**	**11,340**
Other	—	—	—	—	—	**—**	**—**	**6**	**6**
	7,072	3,696	722	31	11,521	**(710)**	**560**	**(25)**	**11,346**
Midstream and Refining	102	—	—	—	102	**—**	**—**	**(14)**	**88**
Intersegment eliminations and other [1]	609	—	—	(51)	558	**—**	**—**	**(62)**	**496**
Total	$ 18,360	$ 3,219	$ 733	$ (30)	$ 22,282	**$ 452**	**$ 1,748**	**$ (88)**	**$ 24,394**

(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 9% to $24,394 million for 2019 from $22,282 million for 2018 (2017 – $18,360 million). The increase was primarily due to higher realized crude oil and NGLs pricing in North America, together with increased crude oil and NGLs sales volumes in the North America Exploration and Production segment following the acquisition of thermal and heavy oil assets from Devon, offsetting the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. Crude oil and NGLs and natural gas pricing are discussed in detail in the "Business Environment" section of this MD&A. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

For 2019, 7% of the Company's crude oil and NGLs and natural gas product sales were generated outside of North America (2018 – 7%; 2017 – 8%). North Sea accounted for 4% of crude oil and NGLs and natural gas product sales for 2019 (2018 – 4%; 2017 – 4%), and Offshore Africa accounted for 3% of crude oil and NGLs and natural gas product sales for 2019 (2018 – 3%; 2017 – 4%).

Daily Production, Before Royalties

	2019	2018	2017
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**405,970**	350,961	359,449
North America – Oil Sands Mining and Upgrading (1)	**395,133**	426,190	282,026
North Sea	**27,919**	23,965	23,426
Offshore Africa	**21,371**	19,662	20,335
	850,393	820,778	685,236
Natural gas (MMcf/d)			
North America	**1,443**	1,490	1,601
North Sea	**24**	32	39
Offshore Africa	**24**	26	22
	1,491	1,548	1,662
Total barrels of oil equivalent (BOE/d)	**1,098,957**	1,078,813	962,264
Product mix			
Light and medium crude oil and NGLs	**13%**	13%	14%
Pelican Lake heavy crude oil	**5%**	6%	6%
Primary heavy crude oil	**8%**	8%	10%
Bitumen (thermal oil)	**15%**	10%	12%
Synthetic crude oil (1)	**36%**	39%	29%
Natural gas	**23%**	24%	29%
Percentage of gross revenue (1) (2)			
(excluding Midstream and Refining revenue)			
Crude oil and NGLs	**94%**	93%	90%
Natural gas	**6%**	7%	10%

(1) SCO production before royalties excludes SCO consumed internally as diesel.
(2) Net of blending costs and excluding risk management activities.

Daily Production, Net of Royalties

	2019	2018	2017
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**356,794**	303,956	312,297
North America – Oil Sands Mining and Upgrading	**375,048**	405,731	274,437
North Sea	**27,866**	23,902	23,382
Offshore Africa	**20,078**	18,450	19,124
	779,786	752,039	629,240
Natural gas (MMcf/d)			
North America	**1,400**	1,432	1,528
North Sea	**24**	32	39
Offshore Africa	**22**	23	20
	1,446	1,487	1,587
Total barrels of oil equivalent (BOE/d)	**1,020,749**	999,857	893,702

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 2019 production before royalties averaged 1,098,957 BOE/d, comparable with 1,078,813 BOE/d in 2018 (2017 – 962,264 BOE/d).

Total production of crude oil and NGLs before royalties for 2019 increased 4% to 850,393 bbl/d from 820,778 bbl/d for 2018 (2017 – 685,236 bbl/d). The increase in crude oil and NGLs production from 2018 primarily reflected production from the acquisition of thermal and heavy oil assets from Devon, offsetting the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. The Company continues to optimize its production volumes across the asset base during curtailment. Crude oil and NGLs production before royalties for 2019 was within the Company's previously issued guidance of 839,000 to 888,000 bbl/d.

Natural gas production before royalties accounted for 23% of the Company's total production in 2019 on a BOE basis. Natural gas production for 2019 decreased 4% to 1,491 MMcf/d from 1,548 MMcf/d for 2018 (2017 – 1,662 MMcf/d). The decrease in natural gas production from 2018 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities due to low natural gas prices. Natural gas production for 2019 was within the Company's previously issued guidance of 1,485 to 1,545 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for 2019 increased 16% to average 405,970 bbl/d from 350,961 bbl/d for 2018 (2017 – 359,449 bbl/d). The increase in production from 2018 primarily reflected the acquisition of thermal and heavy oil assets from Devon that closed in 2019 and increased production of thermal oil due to additional production from Kirby North and pad additions at Primrose, reflecting optimization of curtailment volumes across the Company's asset base.

Thermal oil production before royalties for 2019 averaged 167,942 bbl/d compared with 107,839 bbl/d for 2018 (2017 – 120,140 bbl/d). Production volumes in 2019 primarily reflected volumes from the acquisition of assets from Devon, together with new production from Kirby North and pad additions at Primrose, reflecting optimization of curtailment volumes across the Company's asset base.

Pelican Lake heavy crude oil production before royalties averaged production of 58,855 bbl/d in 2019 compared with 63,082 bbl/d in 2018 (2017 – 51,743 bbl/d).

Natural gas production before royalties for 2019 decreased 3% to average 1,443 MMcf/d from 1,490 MMcf/d for 2018 (2017 – 1,601 MMcf/d). The decrease in natural gas production from 2018 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities due to low natural gas prices.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for 2019 decreased 7% to 395,133 bbl/d from 426,190 bbl/d for 2018 (2017 – 282,026 bbl/d). The decrease in SCO production from 2018 primarily reflected the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. Production in 2019 was impacted by the Government of Alberta mandated production curtailments that came into effect on January 1, 2019.

North Sea

North Sea crude oil production before royalties for 2019 increased 16% to 27,919 bbl/d from 23,965 bbl/d for 2018 (2017 – 23,426 bbl/d). The increase in production from 2018 primarily reflected volumes from new wells.

Offshore Africa

Offshore Africa crude oil production before royalties for 2019 increased 9% to 21,371 bbl/d from 19,662 bbl/d for 2018 (2017 – 20,335 bbl/d). The increase in production from 2018 primarily reflected volumes from new wells drilled at Baobab, partially offset by the cessation of production at the Olowi field, Gabon in December 2018 and natural field declines.

Corporate Production guidance for 2020

The Company targets production levels in 2020 to average between 910,000 bbl/d and 970,000 bbl/d of crude oil and NGLs and between 1,360 MMcf/d and 1,420 MMcf/d of natural gas.

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 held in various storage facilities or FPSOs, as follows:

(bbl)	**2019**	2018	2017
North Sea	**344,726**	71,832	—
Offshore Africa	**519,504**	404,475	121,936
	864,230	476,307	121,936

Exploration and Production

OPERATING HIGHLIGHTS

		2019		2018		2017
Crude oil and NGLs ($/bbl) (1)						
Sales price (2)	**$**	**55.08**	$	46.92	$	48.57
Transportation		**3.48**		3.08		2.80
Realized sales price, net of transportation		**51.60**		43.84		45.77
Royalties		**6.08**		5.08		5.24
Production expense		**13.81**		15.69		14.89
Netback	**$**	**31.71**	$	23.07	$	25.64
Natural gas ($/Mcf) (1)						
Sales price (2)	**$**	**2.34**	$	2.61	$	2.76
Transportation		**0.42**		0.47		0.39
Realized sales price, net of transportation		**1.92**		2.14		2.37
Royalties		**0.08**		0.08		0.11
Production expense		**1.22**		1.36		1.27
Netback	**$**	**0.62**	$	0.70	$	0.99
Barrels of oil equivalent ($/BOE) (1)						
Sales price (2)	**$**	**40.50**	$	34.62	$	35.54
Transportation		**3.14**		2.96		2.66
Realized sales price, net of transportation		**37.36**		31.66		32.88
Royalties		**4.09**		3.27		3.40
Production expense		**11.49**		12.71		11.95
Netback	**$**	**21.78**	$	15.68	$	17.53

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

PRODUCT PRICES

		2019		2018		2017
Crude oil and NGLs ($/bbl) (1) (2)						
North America	**$**	**51.43**	$	41.82	$	45.85
North Sea	**$**	**86.76**	$	87.41	$	69.43
Offshore Africa	**$**	**83.68**	$	90.95	$	67.15
Company average	**$**	**55.08**	$	46.92	$	48.57
Natural gas ($/Mcf) (1) (2)						
North America	**$**	**2.18**	$	2.33	$	2.58
North Sea	**$**	**6.52**	$	12.08	$	8.24
Offshore Africa	**$**	**7.41**	$	7.34	$	6.57
Company average	**$**	**2.34**	$	2.61	$	2.76
Company average ($/BOE) (1) (2)	**$**	**40.50**	$	34.62	$	35.54

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

North America - Product Prices

North America realized crude oil prices increased 23% to average $51.43 per bbl for 2019 from $41.82 per bbl for 2018 (2017 – $45.85 per bbl), primarily due to the narrowing of the WCS Heavy Differential as a result of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019.

North America realized natural gas prices decreased 6% to average $2.18 per Mcf for 2019 from $2.33 per Mcf for 2018 (2017 – $2.58 per Mcf). The decrease primarily reflected increased production levels in North America and the impact of seasonal weather conditions.

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 2019, the Company contributed approximately 174,700 bbl/d of heavy crude oil blends to the WCS stream.

The Company has 20 year transportation agreements to ship 94,000 bbl/d of crude oil on the proposed Trans Mountain Pipeline Expansion. The Canadian Energy Regulator (formerly The National Energy Board) has provided its recommendation that construction of the pipeline should proceed and the Federal cabinet approved the project on June 18, 2019. On February 4, 2020, an appeal from Indigenous groups to the Federal Court of Appeal was dismissed. Pipeline construction, which had commenced, was permitted to continue subject to the outcome of the appeal to the Supreme Court of Canada. Leave to appeal to the Supreme Court of Canada was refused on March 5, 2020.

The Company also has 20 year transportation agreements to ship 200,000 bbl/d of crude oil on the proposed TC Energy Keystone XL Pipeline. On August 23, 2019 the Nebraska Supreme Court ruled that the Nebraska Public Service Commission's route approval was valid. The proponent is awaiting the decision from the Montana Federal Court case filed by various environmental groups challenging the Presidential Permit granted in 2019. Pre-construction activities have commenced and the proponent expects the construction program to be approximately two years once construction has commenced.

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

(Yearly average)		**2019**		2018		2017
Wellhead Price (1) (2)						
Light and medium crude oil and NGLs ($/bbl)	**$**	**49.54**	$	52.87	$	47.78
Pelican Lake heavy crude oil ($/bbl)	**$**	**57.82**	$	43.30	$	48.30
Primary heavy crude oil ($/bbl)	**$**	**55.38**	$	38.98	$	46.88
Bitumen (thermal oil) ($/bbl)	**$**	**48.27**	$	33.66	$	42.49
Natural gas ($/Mcf)	**$**	**2.18**	$	2.33	$	2.58

(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 of $86.76 per bbl for 2019 were comparable with $87.41 per bbl for 2018 (2017 – $69.43 per bbl). Realized crude oil prices per barrel in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting.

Offshore Africa - Product Prices

Offshore Africa realized crude oil prices decreased 8% to average $83.68 per bbl for 2019 from $90.95 per bbl for 2018 (2017 – $67.15 per bbl). Realized crude oil prices per barrel in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The decrease in realized crude oil prices in 2019 reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES

		2019		2018		2017
Crude oil and NGLs ($/bbl) (1)						
North America	**$**	**6.56**	$	5.36	$	5.69
North Sea	**$**	**0.16**	$	0.22	$	0.13
Offshore Africa	**$**	**4.74**	$	6.00	$	4.13
Company average	**$**	**6.08**	$	5.08	$	5.24
Natural gas ($/Mcf) (1)						
North America	**$**	**0.07**	$	0.07	$	0.11
Offshore Africa	**$**	**0.63**	$	1.00	$	0.76
Company average	**$**	**0.08**	$	0.08	$	0.11
Company average ($/BOE) (1)	**$**	**4.09**	$	3.27	$	3.40

(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 2019 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalty rates also reflected fluctuations in the WCS Heavy Differential and changes in the production mix between high and low royalty rate product types.

Crude oil and NGLs royalty rates averaged approximately 13% of product sales for 2019 compared with 14% of product sales for 2018 (2017 – 13%).

Natural gas royalty rates averaged approximately 3% of product sales for 2019 compared with 4% of product sales for 2018 (2017 – 5%).

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 6% for 2019 compared with 7% of product sales for 2018 (2017 – 7%). Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

PRODUCTION EXPENSE

		2019		2018		2017
Crude oil and NGLs ($/bbl) (1)						
North America	**$**	**12.41**	$	13.48	$	12.71
North Sea	**$**	**36.39**	$	39.89	$	36.60
Offshore Africa	**$**	**11.21**	$	26.34	$	24.07
Company average	**$**	**13.81**	$	15.69	$	14.89
Natural gas ($/Mcf) (1)						
North America	**$**	**1.16**	$	1.25	$	1.19
North Sea (2)	**$**	**3.40**	$	5.29	$	3.37
Offshore Africa (2)	**$**	**2.60**	$	2.76	$	2.90
Company average	**$**	**1.22**	$	1.36	$	1.27
Company average ($/BOE) (1)	**$**	**11.49**	$	12.71	$	11.95

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) North Sea and Offshore Africa natural gas production expense for 2019 reflected a decrease of $23 million ($2.66 per Mcf) and $5 million ($0.55 per Mcf) respectively, related to the adoption of IFRS 16.

North America - Production Expense

North America crude oil and NGLs production expense for 2019 decreased 8% to $12.41 per bbl from $13.48 per bbl for 2018 (2017 – $12.71 per bbl). The decrease in crude oil and NGLs production expense for 2019 from 2018 primarily reflected the impact of operating cost synergies captured to date combined with added production from the acquisition of assets from Devon, Kirby North and pad additions at Primrose, offsetting the impact of higher fuel and energy costs. The Company continues to focus on cost control and achieving efficiencies across the entire asset base.

North America crude oil and NGLs production expense for 2019 also reflected a decrease of $22 million ($0.15 per bbl) related to the adoption of IFRS 16.

North America natural gas production expense for 2019 decreased 7% to $1.16 per Mcf from $1.25 per Mcf for 2018 (2017 – $1.19 per Mcf). The decrease in natural gas production expense for 2019 from 2018 primarily reflected the strength of the Company's strategy to own and control its infrastructure, continued focus on cost control, and achieving efficiencies across the entire asset base.

North America natural gas production expense for 2019 also reflected a decrease of $6 million ($0.01 per Mcf) related to the adoption of IFRS 16.

North Sea - Production Expense

North Sea crude oil production expense for 2019 decreased 9% to $36.39 per bbl from $39.89 per bbl for 2018 (2017 – $36.60 per bbl). The decrease in crude oil production expense for 2019 from 2018 primarily reflected increased production volumes, together with fluctuations in the Canadian dollar.

North Sea crude oil production expense for 2019 also reflected a decrease of $21 million ($2.10 per bbl) related to the adoption of IFRS 16.

Offshore Africa - Production Expense

Offshore Africa crude oil production expense was $11.21 per bbl for 2019 compared with $26.34 per bbl for 2018 (2017 – $24.07 per bbl). The decrease in crude oil production expense for 2019 from 2018 primarily reflected the cessation of production at the Olowi field, Gabon in December 2018. Crude oil production expense also reflected the timing of liftings from various fields that have different cost structures, fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar.

Offshore Africa crude oil production expense for 2019 also reflected a decrease of $20 million ($2.56 per bbl) related to the adoption of IFRS 16.

DEPLETION, DEPRECIATION AND AMORTIZATION

($ millions, except per BOE amounts)		**2019**		2018		2017
North America	**$**	**3,326**	$	3,132	$	3,243
North Sea		**308**		257		509
Offshore Africa		**242**		201		205
Expense	**$**	**3,876**	$	3,590	$	3,957
$/BOE (1)	**$**	**15.22**	$	15.12	$	15.82

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

Depletion, depreciation and amortization in 2019 of $15.22 per BOE was comparable with $15.12 per BOE for 2018 (2017 – $15.82 per BOE). Depletion, depreciation and amortization expense for 2019 reflected an increase of $168 million ($0.66 per BOE) related to the adoption of IFRS 16.

ASSET RETIREMENT OBLIGATION ACCRETION

($ millions, except per BOE amounts)	2019	2018	2017
North America	**$ 95**	$ 87	$ 80
North Sea	**28**	29	27
Offshore Africa	**6**	9	9
Expense	**$ 129**	$ 125	$ 116
$/BOE (1)	**$ 0.51**	$ 0.53	$ 0.46

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

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

Asset retirement obligation accretion expense for 2019 decreased 4% to $0.51 per BOE from $0.53 per BOE for 2018 (2017 – $0.46 per BOE). Fluctuations in asset retirement obligation accretion expense on a per BOE basis primarily reflect fluctuating sales volumes.

Oil Sands Mining and Upgrading

OPERATING HIGHLIGHTS

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the Horizon and AOSP sites. Production averaged 395,133 bbl/d during 2019, reflecting the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. Production levels during the year continued to be impacted by the Government of Alberta mandated production curtailments that came into effect January 1, 2019.

Through continuous focus on cost control and efficiencies, the Company has achieved a decrease of $124 million (4%) in adjusted production costs, excluding natural gas costs for 2019 of $3,032 million ($20.89 per bbl), from $3,156 million ($20.39 per bbl) for 2018.

PRODUCT PRICES, ROYALTIES AND TRANSPORTATION

($/bbl) (1)	2019	2018	2017
SCO realized sales price (2)	**$ 70.18**	$ 68.61	$ 63.98
Bitumen value for royalty purposes (3)	**$ 50.79**	$ 40.02	$ 41.05
Bitumen royalties (4)	**$ 3.31**	$ 3.09	$ 1.64
Transportation	**$ 1.29**	$ 1.61	$ 1.54

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.
(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 averaged $70.18 per bbl for 2019, comparable with $68.61 per bbl for 2018 (2017 – $63.98 per bbl).

Transportation expense averaged $1.29 per bbl for 2019, compared with $1.61 per bbl for 2018 (2017 – $1.54 per bbl). Transportation expense for 2019 reflected a decrease of $78 million ($0.53 per bbl) related to the adoption of IFRS 16.

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)		**2019**		2018		2017
Production costs	**$**	**3,276**	$	3,367	$	2,600
Less: costs incurred during turnaround periods		**(119)**		(109)		(216)
Adjusted production costs	**$**	**3,157**	$	3,258	$	2,384
Adjusted production costs, excluding natural gas costs	**$**	**3,032**	$	3,156	$	2,239
Natural gas costs		**125**		102		145
Adjusted production costs	**$**	**3,157**	$	3,258	$	2,384

($/bbl) (1)		**2019**		2018		2017
Adjusted production costs, excluding natural gas costs	**$**	**20.89**	$	20.39	$	21.98
Natural gas costs		**0.86**		0.66		1.42
Adjusted production costs	**$**	**21.75**	$	21.05	$	23.40
Sales (bbl/d)		**397,735**		424,112		279,084

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

Production costs for 2019 were $22.56 per bbl compared with $21.75 per bbl in 2018 (2017 – $25.52 per bbl). Adjusted production costs for 2019 increased 3% to $21.75 per bbl from $21.05 per bbl for 2018 (2017 – $23.40 per bbl). The increase in adjusted production costs per barrel for 2019 from 2018 primarily reflected reduced production volumes due to the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with increased natural gas costs.

Production costs for 2019 also reflected a decrease of $29 million ($0.20 per bbl) related to the adoption of IFRS 16.

DEPLETION, DEPRECIATION AND AMORTIZATION

($ millions, except per bbl amounts)		**2019**		2018		2017
Depletion, depreciation and amortization	**$**	**1,656**	$	1,557	$	1,220
Less: depreciation incurred during turnaround periods		**(69)**		(56)		(213)
Adjusted depletion, depreciation and amortization	**$**	**1,587**	$	1,501	$	1,007
$/bbl (1)	**$**	**10.94**	$	9.70	$	9.89

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

Adjusted depletion, depreciation and amortization expense for 2019 increased 13% to $10.94 per bbl from $9.70 per bbl for 2018 (2017 – $9.89 per bbl). This increase primarily reflected fluctuations in sales volumes from different underlying operations, a proactive piping replacement at Horizon, and the adoption of IFRS 16. Depletion, depreciation and amortization expense for 2019 also reflected an increase of $92 million ($0.63 per bbl) related to the adoption of IFRS 16.

ASSET RETIREMENT OBLIGATION ACCRETION

($ millions, except per bbl amounts)		**2019**		2018		2017
Expense	**$**	**61**	$	61	$	48
$/bbl (1)	**$**	**0.42**	$	0.40	$	0.47

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

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

Asset retirement obligation accretion expense for 2019 increased 5% to $0.42 per bbl from $0.40 per bbl for 2018 (2017 – $0.47 per bbl). Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

Midstream and Refining

($ millions)	2019	2018	2017
Revenue	**$ 88**	$ 102	$ 102
Less:			
Production expense	**20**	21	16
Depreciation	**14**	14	9
Equity loss (gain) from Redwater Partnership	**287**	5	(31)
Gain on revaluation of properties	**—**	—	(114)
Segment earnings (loss) before taxes	**$ (233)**	$ 62	$ 222

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 30% of the Company's heavy crude oil production was 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.

Redwater Partnership has entered into agreements to construct and operate a 50,000 bbl/d bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 bbl/d of bitumen feedstock for the Company and 37,500 bbl/d of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2018, Redwater Partnership commenced commissioning activities in the Project's light oil units while continuing work on the heavy oil units. In the first quarter of 2019, the light oil units transitioned from pre-commissioning and startup to operations and are processing synthetic crude oil into refined products. In December 2019, the light oil refinery completed activities relating to the planned maintenance shutdown. The Project continues to operate as a light oil refinery and will continue to process synthetic crude oil into refined products until the heavy oil units can reliably commence commercial processing of bitumen. Design modifications to the reactor burners in the gasifier unit are ongoing and have continued through the first quarter of 2020. As at December 31, 2019, the total estimate of capital costs incurred for the Project, net of margins from pre-commercial sales, was approximately $10 billion.

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 the agreed debt to equity ratio of 80/20. As at December 31, 2019, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $213 million, for a Company total of $652 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 tolls, 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 tolls over the 30-year tolling period. As at December 31, 2019, the Company had recognized $130 million in prepaid cost of service tolls (December 31, 2018 – $62 million).

Redwater Partnership has a secured $3,500 million syndicated credit facility, of which $2,000 million is revolving and matures in June 2021 and the remaining $1,500 million is fully drawn on a non-revolving basis. During 2019, Redwater Partnership extended the $1,500 million non-revolving facility, previously scheduled to mature in February 2020, to February 2021. As at December 31, 2019, Redwater Partnership had borrowings of $2,715 million under the secured syndicated credit facility.

The Company recognized an equity loss from Redwater Partnership of $287 million for 2019 (2018 – loss of $5 million), reducing the carrying value in Redwater Partnership to $nil. The unrecognized share of losses from Redwater Partnership for 2019 was $59 million. The equity loss for 2019 primarily reflected the impact of Redwater Partnership deferring cost of service toll revenue until it achieves commercial operations and is reliably processing toll payers' bitumen.

Corporate and Other

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	2019	2018	2017
Expense	**$ 344**	$ 325	$ 319
$/BOE (1)	**$ 0.86**	$ 0.83	$ 0.91

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

Administration expense for 2019 increased 4% to $0.86 per BOE from $0.83 per BOE for 2018 (2017 – $0.91 per BOE). Administration expense per BOE increased for 2019 from 2018 primarily due to higher personnel costs, including those associated with the acquisition of assets from Devon. Administration expense for 2019 also reflected a decrease of $23 million ($0.06 per BOE) related to the adoption of IFRS 16.

SHARE-BASED COMPENSATION

($ millions)	2019	2018	2017
Expense (recovery)	**$ 223**	$ (146)	$ 134

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 PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met.

The Company recorded a $223 million share-based compensation expense for 2019, primarily as a result of the measurement 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 expense for 2019 was $49 million related to PSUs granted to certain executive employees (2018 – $8 million; 2017 – $5 million). For 2019, the Company charged $5 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (2018 – $19 million recovered, 2017 – $14 million charged).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	2019	2018	2017
Expense, gross	**$ 889**	$ 808	$ 713
Less: capitalized interest	**53**	69	82
Expense, net	**$ 836**	$ 739	$ 631
$/BOE (1)	**$ 2.09**	$ 1.88	$ 1.79
Average effective interest rate	**4.0%**	3.9%	3.8%

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

Gross interest and other financing expense for 2019 increased from 2018 primarily due to interest expense on lease liabilities recognized due to the adoption of IFRS 16. Capitalized interest of $53 million for 2019 was related to Kirby North and residual project activities at Horizon.

Net interest and other financing expense for 2019 increased 11% to $2.09 per BOE from $1.88 per BOE for 2018 (2017 – $1.79 per BOE). The increase for 2019 from 2018 primarily reflected the adoption of IFRS 16, together with lower capitalized interest and higher levels of debt in 2019. Net interest and other financing expense for 2019 reflected an increase of $70 million ($0.18 per BOE) related to the adoption of IFRS 16.

The Company's average effective interest rate of 4.0% for 2019 was consistent with 2018.

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)	**2019**	2018	2017
Crude oil and NGLs financial instruments	**$ 52**	$ (27)	$ (32)
Natural gas financial instruments	**(1)**	5	(7)
Foreign currency contracts	**13**	(77)	37
Realized loss (gain)	**$ 64**	$ (99)	$ (2)
Crude oil and NGLs financial instruments	**$ (17)**	$ 16	$ —
Natural gas financial instruments	**15**	(4)	(6)
Foreign currency contracts	**15**	(47)	43
Unrealized loss (gain)	**$ 13**	$ (35)	$ 37
Net loss (gain)	**$ 77**	$ (134)	$ 35

During 2019, net realized risk management losses were related to the settlement of crude oil and NGLs financial instruments and foreign currency contracts. The Company recorded a net unrealized loss of $13 million ($14 million after-tax) on its risk management activities for 2019 (2018 – $35 million unrealized gain, $36 million after-tax; 2017 – $37 million unrealized loss, $33 million after-tax).

Complete details related to outstanding derivative financial instruments at December 31, 2019 are disclosed in note 19 to the Company's audited consolidated financial statements.

FOREIGN EXCHANGE

($ millions)	**2019**	2018	2017
Net realized (gain) loss	**$ (22)**	$ 121	$ 34
Net unrealized (gain) loss	**(548)**	706	(821)
Net (gain) loss [(1)]	**$ (570)**	$ 827	$ (787)

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

The net realized foreign exchange gain for 2019 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for 2019 was primarily related to the impact of the stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (2019 – unrealized loss of $71 million, 2018 – unrealized gain of $118 million, 2017 – unrealized loss of $280 million). The US/Canadian dollar exchange rate at December 31, 2019 was US$0.7713 (December 31, 2018 – US$0.7328, December 31, 2017 – US$0.7988).

INCOME TAXES

($ millions, except income tax rates)	2019	2018	2017
North America (1)	**$ 354**	$ 312	$ (145)
North Sea	**112**	28	57
Offshore Africa	**44**	54	45
PRT – North Sea	**(89)**	(29)	(132)
Other taxes	**13**	9	11
Current income tax expense (recovery)	**434**	374	(164)
Deferred corporate income tax (recovery) expense	**(895)**	540	586
Deferred PRT expense – North Sea	**1**	17	54
Deferred income tax (recovery) expense	**(894)**	557	640
	(460)	931	476
Income tax rate and other legislative changes	**1,618**	—	(10)
	$ 1,158	$ 931	$ 466
Effective income tax rate on adjusted net earnings from operations (2)	**25%**	21%	27%

(1) Includes North America Exploration and Production, Midstream and Refining, 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 2019 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 and tax rates in the countries in which the Company operates, in relation to net earnings.

The current corporate income tax and PRT in the North Sea in 2019 and the comparable years included the impact of carrybacks of abandonment expenditures related to decommissioning activities at the Company's platforms in the North Sea.

During 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by $1,618 million.

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.

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.

During 2019, the Company filed Scientific Research and Experimental Development claims of approximately $250 million (2018 – $265 million; 2017 – $345 million) relating to qualifying research and development expenditures for Canadian income tax purposes.

Net Capital Expenditures (1)

($ millions)	2019	2018	2017
Exploration and Evaluation			
Net property acquisitions (dispositions) (2) (3)	**$ 90**	$ (74)	$ 26
Net expenditures	**74**	122	123
Total Exploration and Evaluation	**164**	48	149
Property, Plant and Equipment			
Net property acquisitions (2) (3)	**3,208**	98	1,219
Well drilling, completion and equipping	**775**	1,446	1,001
Production and related facilities	**1,028**	1,262	860
Capitalized interest and other	**81**	106	91
Total Property, Plant and Equipment	**5,092**	2,912	3,171
Total Exploration and Production	**5,256**	2,960	3,320
Oil Sands Mining and Upgrading			
Project costs (4)	**436**	438	821
Sustaining capital	**933**	665	561
Turnaround costs	**118**	112	155
Acquisitions of Exploration and Evaluation assets (3) (5)	**—**	218	219
Net property acquisitions (3)	**—**	—	11,604
Capitalized interest and other	**38**	14	76
Total Oil Sands Mining and Upgrading	**1,525**	1,447	13,436
Midstream and Refining	**10**	13	80
Abandonments (6)	**296**	290	274
Head office	**34**	21	19
Total net capital expenditures	**$ 7,121**	$ 4,731	$ 17,129
By segment			
North America (2) (3)	**$ 4,831**	$ 2,671	$ 3,056
North Sea	**196**	131	160
Offshore Africa	**229**	158	104
Oil Sands Mining and Upgrading (3) (5)	**1,525**	1,447	13,436
Midstream and Refining	**10**	13	80
Abandonments (6)	**296**	290	274
Head office	**34**	21	19
Total	**$ 7,121**	$ 4,731	$ 17,129

(1) Net capital expenditures exclude the impact of lease assets and fair value and revaluation adjustments, and include non-cash transfers of property, plant and equipment to inventory due to change in use.
(2) During 2019, cash consideration for the acquisition of assets from Devon included $91 million for exploration and evaluation assets and $3,126 million for property, plant and equipment.
(3) During 2017, total purchase consideration for the acquisition of AOSP of $12,157 million included $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.
(4) Includes Horizon Phase 2/3 construction costs.
(5) In the third quarter of 2018, total purchase consideration for the acquisition of the Joslyn oil sands project included $222 million for exploration and evaluation assets and $4 million for asset retirement obligations assumed. 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.
(6) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

NET CAPITAL EXPENDITURES, AS RECONCILED TO CASH FLOWS USED IN INVESTING ACTIVITIES

($ millions)		**2019**		2018		2017
Cash flows used in investing activities	**$**	**7,255**	$	4,814	$	13,102
Net change in non-cash working capital (1) (2)		**(430)**		(345)		22
Investment in other long-term assets		**—**		(28)		(87)
Share consideration in business acquisitions		**—**		—		3,818
Abandonment expenditures (3)		**296**		290		274
Net capital expenditures	**$**	**7,121**	$	4,731	$	17,129

(1) Includes net working capital and other long-term assets of $195 million related to the acquisition of assets from Devon in 2019.
(2) Includes net working capital of $291 million related to the acquisition of AOSP in 2017.
(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 2019 were $7,121 million compared with $4,731 million for 2018 (2017 – $17,129 million). Net capital expenditures for 2019 included $3,217 million of cash consideration to acquire assets from Devon.

DRILLING ACTIVITY (1)

(number of wells)	**2019**	2018	2017
Net successful natural gas wells	**19**	18	21
Net successful crude oil wells (2)	**86**	483	495
Dry wells	**3**	9	7
Stratigraphic test / service wells	**447**	615	289
Total	**555**	1,125	812
Success rate (excluding stratigraphic test / service wells)	**97%**	98%	99%

(1) Includes drilling activity for North America and International segments.
(2) Includes bitumen wells.

North America

During 2019, the Company targeted 20 net natural gas wells, 42 net primary heavy crude oil wells, 3 net bitumen (thermal oil) wells and 37 net wells targeting light crude oil.

North Sea

During 2019, the Company completed 5 gross production wells (4.9 on a net basis) and 2 gross injection wells (1.9 on a net basis), successfully completing the 2019 drilling program in the North Sea.

Offshore Africa

During 2019, the Company completed 1 gross production well (0.6 on a net basis) and 2 gross injection wells (1.2 on a net basis) at Baobab and 1 gross appraisal well (0.6 on a net basis) at Kossipo.

Liquidity and Capital Resources

($ millions, except ratios)		2019		2018		2017
Working capital (1)	**$**	**241**	$	(601)	$	513
Long-term debt (2) (3)	**$**	**20,982**	$	20,623	$	22,458
Less: cash and cash equivalents		**139**		101		137
Long-term debt, net	**$**	**20,843**	$	20,522	$	22,321
Share capital	**$**	**9,533**	$	9,323	$	9,109
Retained earnings		**25,424**		22,529		22,612
Accumulated other comprehensive income (loss)		**34**		122		(68)
Shareholders' equity	**$**	**34,991**	$	31,974	$	31,653
Debt to book capitalization (3) (4)		**37%**		39%		41%
Debt to market capitalization (3) (5)		**30%**		34%		29%
After-tax return on average common shareholders' equity (6)		**16%**		8%		8%
After-tax return on average capital employed (3) (7)		**11%**		6%		6%

(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 (2019 - $2,391 million, 2018 - $1,141 million, 2017 - $1,877 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 for the year; as a percentage of average common shareholders' equity for the year.
(7) Calculated as net earnings plus after-tax interest and other financing expense for the year; as a percentage of average capital employed for the year.

As at December 31, 2019, 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;
- Reviewing the Company's borrowing capacity:
  - During 2019, the Company fully repaid and cancelled the $1,800 million non-revolving term credit facility scheduled to mature in May 2020.
  - During 2019, the $2,200 million non-revolving term credit facility, originally due October 2020, was extended to February 2023 and increased to $2,650 million.
  - During 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon. The facility matures in June 2022 and is subject to annual amortization of 5% of the original balance.
  - Borrowings under the Company's non-revolving credit 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. As at December 31, 2019, the non-revolving credit facilities were fully drawn.

- During 2019, the Company extended the $2,425 million revolving syndicated credit facility, of which $330 million was originally due June 2019 and $2,095 million was originally due June 2021, to June 2023. The other $2,425 million revolving credit facility matures in June 2022. Each of the $2,425 million revolving credit 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 the Company's revolving term credit 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 2019, the Company reduced the £15 million demand credit facility, related to the Company's North Sea operations, to £5 million.
- During 2019, the Company repaid $500 million of 2.60% medium-term notes and $500 million of 3.05% medium-term notes.
- 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 revolving bank credit facilities for amounts outstanding under this program.
- During 2019, the Company filed new base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, expiring in August 2021, and replacing the Company's previous base shelf prospectuses, which would have expired 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, 2019, 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, 2019, the Company had in place revolving bank credit facilities of $4,959 million of which $4,737 million was available. Additionally, the Company had in place fully drawn term credit facilities of $6,650 million. This excludes certain other dedicated credit facilities supporting letters of credit.

As at December 31, 2019, the Company had total US dollar denominated debt with a carrying amount of $15,102 million (US$11,649 million), before transaction costs and original issue discounts. This included $6,545 million (US$5,049 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$3,999 million). The fixed repayment amount of these hedging instruments is $6,429 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $116 million to $14,986 million as at December 31, 2019.

Net long-term debt was $20,843 million at December 31, 2019, resulting in a debt to book capitalization ratio of 37% (December 31, 2018 – 39%, December 31, 2017 – 41%); 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, 2019 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, 2019, 140,000 MMbtu/d of currently forecasted natural gas volumes were hedged using AECO basis swaps for January 2020 to March 2020. Additionally, at December 31, 2019, 102,500 GJ/d of currently forecasted natural gas volumes were hedged using AECO fixed price swaps for April 2020 to October 2020. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2019 are discussed in note 19 of the Company's audited consolidated financial statements.

The maturity dates of long-term debt and other long-term liabilities and related interest payments were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt (1)	$ 2,391	$ 1,552	$ 8,921	$ 8,226
Other long-term liabilities (2)	$ 370	$ 196	$ 436	$ 1,014
Interest and other financing expense (3)	$ 881	$ 813	$ 1,771	$ 4,856

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.
(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows: less than one year, $233 million; one to less than two years, $171 million; two to less than five years, $391 million; and thereafter, $1,014 million.
(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2019.

SHARE CAPITAL

As at December 31, 2019, there were 1,186,857,000 common shares outstanding (December 31, 2018 – 1,201,886,000 common shares) and 47,646,000 stock options outstanding. As at March 17, 2020, the Company had 1,180,854,000 common shares outstanding and 53,143,000 stock options outstanding.

On March 4, 2020, the Board of Directors approved an increase in the quarterly dividend to $0.425 per common share, beginning with the dividend payable on April 1, 2020. On March 6, 2019, the Board of Directors approved an increase in the quarterly dividend to $0.375 per common share. On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share. On March 1, 2017, the Board of Directors approved an increase in the quarterly dividend to $0.275 per common share. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On May 21, 2019, the Company's application was approved for a Normal Course Issuer Bid ("NCIB") to purchase through the facilities at the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 59,729,706 common shares, over a 12-month period commencing May 23, 2019 and ending May 22, 2020. The Company's NCIB approved in May 2018 expired on May 22, 2019.

During 2019, the Company purchased for cancellation 25,900,000 common shares at a weighted average price of $36.32 per common share for a total cost of $941 million. Retained earnings were reduced by $738 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2019, the Company purchased 6,970,000 common shares at a weighted average price of $38.84 per common share for a total cost of $271 million.

Commitments and Contingencies

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2019 (1):

($ millions)	2020	2021	2022	2023	2024	Thereafter
Product transportation (2) (3)	$ 730	$ 722	$ 637	$ 726	$ 699	$ 7,907
North West Redwater Partnership service toll (4)	$ 133	$ 167	$ 157	$ 164	$ 156	$ 2,815
Offshore vessels and equipment	$ 69	$ 63	$ 9	$ —	$ —	$ —
Field equipment and power	$ 27	$ 21	$ 20	$ 21	$ 20	$ 249
Other	$ 26	$ 20	$ 17	$ 17	$ 17	$ 30

(1) Subsequent to adoption of IFRS 16, the Company reports its payments for lease liabilities in the maturity table in the 'Liquidity and Capital Resources' section of this MD&A.
(2) On June 27, 2019, the Company assumed $2,381 million of product transportation commitments related to the acquisition of assets from Devon.
(3) Includes commitments pertaining to a 20 year product transportation agreement on the Trans Mountain Pipeline Expansion. In addition, the Company has entered into certain product transportation agreements on pipelines that have not yet received regulatory and other approvals. The Company may be required to reimburse certain construction costs to the service provider under certain conditions.
(4) 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 tolls, currently consisting of interest and fees, with principal repayments beginning in 2020. Included in the cost of service tolls is $1,260 million of interest payable over the 30 year tolling period.

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, 2019, 2018 and 2017, 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 and prepared 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 following are reconciliation tables of the company gross proved and proved plus probable reserves using forecast prices and costs as at the effective date of December 31, 2019:

Proved Reserves	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2018	399	182	305	1,540	6,091	6,652	267	9,893
Discoveries	—	—	—	—	—	—	—	—
Extensions	3	6	—	17	385	112	11	440
Infill Drilling	5	5	—	—	—	206	8	52
Improved Recovery	—	—	—	237	—	2	—	238
Acquisitions	2	46	—	769	—	35	1	823
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(5)	(3)	(3)	—	—	(228)	(5)	(54)
Technical Revisions	(9)	(3)	12	(64)	20	225	11	3
Production	(37)	(30)	(21)	(61)	(144)	(544)	(16)	(401)
December 31, 2019 (1)	**357**	**202**	**293**	**2,438**	**6,352**	**6,460**	**275**	**10,993**

Proved Plus Probable Reserves	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2018	575	252	445	3,059	7,032	9,734	397	13,382
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	12	—	26	—	177	17	89
Infill Drilling	6	7	—	—	—	476	15	108
Improved Recovery	—	—	—	329	—	3	—	329
Acquisitions	2	68	—	955	—	42	1	1,033
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(4)	(3)	(3)	—	—	(266)	(6)	(60)
Technical Revisions	(28)	(12)	4	(198)	9	(16)	(1)	(228)
Production	(37)	(30)	(21)	(61)	(144)	(544)	(16)	(401)
December 31, 2019 (1)	**519**	**293**	**425**	**4,108**	**6,897**	**9,607**	**408**	**14,252**

(1) Information in the reserves data tables may not add due to rounding. BOE values as presented may not calculate due to rounding.

At December 31, 2019, the company gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 9,917 MMbbl, and company gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 12,651 MMbbl. Proved reserves additions and revisions replaced 465% of 2019 production. Additions to proved reserves resulting from exploration and development activities, acquisitions, dispositions and future offset additions amounted to 1,494 MMbbl, and additions to proved plus probable reserves amounted to 1,443 MMbbl. Net negative revisions amounted to 51 MMbbl for proved reserves and 241 MMbbl for proved plus probable reserves, primarily due to technical revisions.

At December 31, 2019, the company gross proved natural gas reserves totaled 6,460 Bcf, and company gross proved plus probable natural gas reserves totaled 9,607 Bcf. Proved reserves additions and revisions replaced 65% of 2019 production. Additions to proved reserves resulting from exploration and development activities, acquisitions, dispositions and future offset additions amounted to 355 Bcf, and additions to proved plus probable reserves amounted to 698 Bcf.

Net negative revisions amounted to 4 Bcf for proved reserves and 282 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 information is annually disclosed in the AIF.

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.

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:

- Volatility in the prevailing prices of crude oil and NGLs and natural gas;
- 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;
- 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, including GHG and carbon;
- 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;
- Epidemics or pandemics, such as the newly identified COVID-19 virus pandemic, have the potential to disrupt the Company's operations, projects and financial condition through the disruption of the local or global supply chain and transportation services, or the loss of manpower resulting from quarantines that affect the Company's labour pools in their local communities, workforce camps or operating sites or that are instituted by local health authorities as a precautionary measure, any of which may require the Company to temporarily reduce or shutdown its operations depending on the extent and severity of a potential outbreak and the areas or operations impacted. Depending on the severity, a large scale epidemic or pandemic could impact the international demand for

commodities and have a corresponding impact on the prices realized by the Company, which could have a material adverse affect on the Company's financial condition;

- 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;
- Liquidity risk related to the Company's ability to fulfill financial obligations as they become due or ability to liquidate assets in a timely manner at a reasonable price; 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. 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 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 has safety, integrity and environmental management systems to recover and process crude oil and natural gas resources safely, efficiently, and in an environmentally sustainable manner and mitigate risk.

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, 2019.

Environment

The Company has a Corporate Statement on Environmental Management which affirms that environmental stewardship is a fundamental value of the Company. 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. 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 interests and values of the people using the land in proximity to its operations, and where appropriate, adapts projects to recognize those matters.

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. Existing and expected legislation and regulations may require the Company to address and mitigate the effect of its activities on the environment. The Company believes 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 incorporate working with legislators and regulators on any new or revised policies, legislation or regulations to 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 quality and emissions, ground and surface 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;
- Mitigation of the Company's climate change impacts through implementation of various CO_2 emissions reduction and carbon capture projects including: CO_2 injection for EOR, CO_2 sequestration in tailings and the Quest carbon capture and storage facility; a methane emissions reduction program, including solution gas conservation to reduce methane venting, and an equipment retrofit program to reduce methane emissions from pneumatic equipment; and 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;
- Groundwater monitoring for all thermal in situ and mine operations;
- Effective reclamation and decommissioning programs 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 for the enhancement of biodiversity and the establishment of functional wildlife habitats. In the Company's International operations, decommissioning activities continued in Gabon as well as Murchison and Ninian platforms in the North Sea;
- 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;
- An active spill prevention and management program; and
- An internal environmental management system for compliance audit and inspection programs 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 3.8% (2018 – 5.0%; 2017 – 4.7%). For 2019, the Company's capital expenditures included $296 million for abandonment expenditures (2018 – $290 million; 2017 – $274 million). The Company's estimated discounted ARO at December 31, 2019 was as follows:

($ millions)		**2019**		2018
Exploration and Production				
North America	**$**	**2,792**	$	1,665
North Sea		**816**		707
Offshore Africa		**161**		134
Oil Sands Mining and Upgrading		**2,000**		1,379
Midstream and Refining		**2**		1
	$	**5,771**	$	3,886

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.

GREENHOUSE GAS AND OTHER EMISSIONS

The Company has a large, diversified and balanced portfolio and a risk management strategy which incorporates an integrated GHG emissions reduction strategy and investments in technology and innovation to improve its GHG performance. The Company's integrated GHG emissions reduction strategy includes: 1) integrating emissions reduction in project planning and operations; 2) leveraging technology to create value and enhance performance; 3) investing in research and development and supporting collaboration with industry, entrepreneurs, academia and governments; 4) focusing on continuous improvement to drive long-term emissions reduction; 5) leading in carbon capture, sequestration and storage; 6) engaging in policy and regulatory development (including trading capacity and offsetting emissions); and, 7) reviewing and developing new business opportunities and trends.

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 to support emissions reductions and properly reflect a balanced approach to sustainable development. 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.

Governments in jurisdictions in which the Company operates have developed or are developing GHG regulations as part of their national and international climate change commitments. The Company uses existing GHG regulations to determine the impact of compliance costs on current and future projects. The Company monitors the development of GHG regulations on an ongoing basis in the jurisdictions in which it operates to assess the impact of future regulatory developments on the Company's operations and planned projects. 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.

Carbon pricing regulatory systems in all provinces are subject to annual review by the federal government to assess the adequacy of the provincial systems against the federal Greenhouse Gas Pollution Pricing Act. Such future reviews may affect the carbon price and/or the stringency of provincial systems.

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. In 2019, nine of the Company's operated facilities: Horizon, AOSP, the Primrose/Wolf Lake, Kirby South, Jackfish, Peace River, Hays, Wapiti and the Brintnell power generation facility were subject to compliance under the regulation. Effective January 1, 2020, the CCIR was replaced with the Technology Innovation and Emissions Reduction Regulation ("TIER"). The coverage of TIER has expanded to include all of the Company's assets in Alberta (as an alternative to the federal fuel charge). The carbon price in Alberta is currently $30/tonne for emissions above the TIER-regulated limits, and the Alberta government has announced its intention to increase the price to $40/tonne in 2021 and $50/tonne in 2022, in alignment with the federal carbon pricing schedule. Facilities with emissions in previous years above 100,000 tonnes of CO_2e/year, or that have voluntarily opted into TIER are required to comply with 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 is subject to a reduction target in 2020.

In British Columbia, carbon tax is currently being assessed at $40/tonne of CO_2e on fuel consumed and gas flared in the province, with the rate increasing to $45/tonne on April 1, 2020 and to $50/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 emissions intensive trade exposed (EITE) sectors.

As part of its Prairie Resilience Plan, the Saskatchewan government has released a regulation ("The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations") that applies to facilities emitting more than 25 kilotonnes of CO_2e annually and requires the North Tangleflags in situ heavy oil facility and the Senlac in situ heavy crude oil facility to meet reduction targets for GHG emissions in 2019. This regulation also enables facilities below the threshold to aggregate and opt into the Saskatchewan regulatory system as an alternative to the federal fuel charge.

In Manitoba, the federal output-based pricing system applies for facilities with emissions greater than or equal to 10 kilotonnes of CO_2e annually, and the federal fuel charge applies for facilities with emissions of less than 10 kilotonnes of CO_2e annually.

The federal government's methane regulation has come into effect on January 1, 2020 and will apply nationally unless provinces reach equivalency agreements with the federal government, under which the federal regulation would not be in effect for those jurisdictions which have equivalency agreements. The Alberta government has also finalized regulations to reduce methane emissions from the upstream oil and gas sector (consistent with the federal reduction target), which came into effect on January 1, 2020. 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.

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

In 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. Following the UK's withdrawal from the European Union ("EU") on January 31, 2020, the UK will continue to participate in the EU ETS for the 2020 compliance year, with decisions on the post-2020 GHG regulatory framework expected in 2020. 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.

Accounting Policies and Standards

CHANGES IN ACCOUNTING POLICIES

IFRS 16 "Leases"

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaced IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and generally requires balance sheet recognition for all leases. Certain short-term (12 months or less) and low-value leases are exempt from the requirements, and the Company continues to treat these leases as expenses. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are also exempt from the standard.

The Company adopted IFRS 16 on January 1, 2019 using the modified retrospective approach 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 have not been restated and continue to be reported using the Company's previous accounting policy under IAS 17.

On adoption, the Company applied 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 twelve months or less as at January 1, 2019 were treated as short-term leases;
- exclusion of initial direct costs for the measurement of lease assets at the date of initial application; and
- the application of the Company's previous assessment for onerous contracts under IAS 37, instead of re-assessing impairment on the Company's lease assets as at January 1, 2019.

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

In connection with the adoption of IFRS 16, the Company recognized lease liabilities (included in other long-term liabilities) of $1,539 million, measured at the present value of the remaining lease payments, discounted at the Company’s incremental borrowing rate at the transition date. Lease assets were measured at an amount equal to the lease liability. Under the new standard, the Company reports cash outflows for payment of the principal portion of the lease liability as cash flows used in financing activities. The interest portion of the lease payments is classified as cash flows from operating activities.

For further details of the Company's lease assets and lease liabilities on transition to the new Leases standard at January 1, 2019 and as at December 31, 2019, refer to the audited consolidated financial statements for the year ended December 31, 2019.

The impacts of the adoption of IFRS 16 are discussed within the respective sections of this MD&A. The most significant impacts of the adoption of the new Leases standard are as follows:

- Cash flow from operating activities and adjusted funds flow increased as the principal portion of lease payments, previously classified as cash flows from operating activities is now reported as cash flows used in financing activities;
- Increased depletion, depreciation and amortization expense and interest expense;
- Decreased production expense, transportation expense and administration expense; and
- Commitments for leases, previously reported in the "Commitments and Contingencies" section of this MD&A, are now reported in the maturity table in the "Liquidity and Capital Resources" section of this MD&A.

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 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 prospectively adopted the amendments on January 1, 2020.

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 prospectively adopted the amendments on January 1, 2020.

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, 2019.

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 3.8%. 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.

H) Leases

Purchase, extension and termination options are included in certain of the Company's leases to provide operational flexibility. To measure the lease liability, the Company uses judgment to assess the likelihood of exercising these options. These assessments are reviewed when significant events or circumstances indicate that the likelihood of exercising these options may have changed. The Company also uses estimates to determine its incremental borrowing costs if the interest rate implicit in the lease is not readily determinable.

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, 2019, 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, 2019, 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 2019 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.

2020 CAPITAL BUDGET

Effective and efficient operations will continue to be a focus of the Company in 2020. Our 2020 capital budget is flexible and disciplined and was originally targeted, when finalized on December 4, 2019, at approximately $4,050 million, driving corporate production guidance volumes of between 1,137,000 and 1,207,000 BOE/d. Subsequent to year end 2019, in early March 2020, as a result of the volatility in crude oil pricing, Canadian Natural reduced its 2020 capital budget by approximately $100 million to $3,950 million. With the continued volatility in commodity pricing, the Company in mid-March, 2020 identified and implemented further opportunities to reduce its 2020 capital spending budget to approximately $2,960 million, but with no impact to our stated production guidance of between 1,137,000 and 1,207,000 BOE/d. Decisions regarding additional opportunities to further reduce capital spending will be made as part of the Company’s prudent management of its capital expenditures.

Other

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flows from operating activities and net earnings due to changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2019, 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** ($ millions)	**Net earnings** (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl				
Excluding financial derivatives	$ 292	$ 0.24	$ 292	$ 0.24
Including financial derivatives	$ 292	$ 0.24	$ 292	$ 0.24
Natural gas – AECO C$0.10/Mcf (1)				
Excluding financial derivatives	$ 23	$ 0.02	$ 23	$ 0.02
Including financial derivatives	$ 21	$ 0.02	$ 21	$ 0.02
Volume changes				
Crude oil – 10,000 bbl/d	$ 128	$ 0.11	$ 100	$ 0.08
Natural gas – 10 MMcf/d	$ 2	$ —	$ —	$ —
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 161 -165	$ 0.14	$ 52	$ 0.04
Interest rate change – 1%	$ 50	$ 0.04	$ 50	$ 0.04

(1) For details of financial instruments in place, refer to note 19 to the Company's audited consolidated financial statements as at December 31, 2019.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2019	2018	2017
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	**319,437**	**344,665**	**450,662**	**506,571**	**405,970**	350,961	359,449
North America – Oil Sands Mining and Upgrading	**416,206**	**374,500**	**432,203**	**357,856**	**395,133**	426,190	282,026
North Sea	**25,714**	**27,594**	**27,454**	**30,860**	**27,919**	23,965	23,426
Offshore Africa	**22,155**	**23,650**	**21,227**	**18,495**	**21,371**	19,662	20,335
Total	**783,512**	**770,409**	**931,546**	**913,782**	**850,393**	820,778	685,236
Natural gas (MMcf/d)							
North America	**1,454**	**1,482**	**1,425**	**1,411**	**1,443**	1,490	1,601
North Sea	**28**	**23**	**20**	**25**	**24**	32	39
Offshore Africa	**28**	**27**	**24**	**19**	**24**	26	22
Total	**1,510**	**1,532**	**1,469**	**1,455**	**1,491**	1,548	1,662
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	**561,755**	**591,738**	**688,175**	**741,673**	**646,443**	599,310	626,230
North America – Oil Sands Mining and Upgrading	**416,206**	**374,500**	**432,203**	**357,856**	**395,133**	426,190	282,026
North Sea	**30,466**	**31,346**	**30,758**	**35,052**	**31,915**	29,264	29,989
Offshore Africa	**26,785**	**28,216**	**25,225**	**21,695**	**25,466**	24,049	24,019
Total	**1,035,212**	**1,025,800**	**1,176,361**	**1,156,276**	**1,098,957**	1,078,813	962,264

PER UNIT RESULTS – EXPLORATION AND PRODUCTION

	Q1	Q2	Q3	Q4	2019	2018	2017
Crude oil and NGLs ($/bbl) (1)							
Sales price (2)	**$ 53.98**	**$ 63.45**	**$ 55.19**	**$ 49.60**	**$ 55.08**	$ 46.92	$ 48.57
Transportation	**3.26**	**3.35**	**3.69**	**3.53**	**3.48**	3.08	2.80
Realized sales price, net of transportation	**50.72**	**60.10**	**51.50**	**46.07**	**51.60**	43.84	45.77
Royalties	**5.95**	**6.35**	**6.02**	**6.03**	**6.08**	5.08	5.24
Production expense	**16.04**	**14.42**	**13.25**	**12.46**	**13.81**	15.69	14.89
Netback	**$ 28.73**	**$ 39.33**	**$ 32.23**	**$ 27.58**	**$ 31.71**	$ 23.07	$ 25.64
Natural gas ($/Mcf) (1)							
Sales price (2)	**$ 3.09**	**$ 1.98**	**$ 1.64**	**$ 2.64**	**$ 2.34**	$ 2.61	$ 2.76
Transportation	**0.46**	**0.40**	**0.40**	**0.43**	**0.42**	0.47	0.39
Realized sales price, net of transportation	**2.63**	**1.58**	**1.24**	**2.21**	**1.92**	2.14	2.37
Royalties	**0.12**	**0.08**	**0.01**	**0.11**	**0.08**	0.08	0.11
Production expense	**1.33**	**1.23**	**1.12**	**1.17**	**1.22**	1.36	1.27
Netback	**$ 1.18**	**$ 0.27**	**$ 0.11**	**$ 0.93**	**$ 0.62**	$ 0.70	$ 0.99
Barrels of oil equivalent ($/BOE) (1)							
Sales price (2)	**$ 39.27**	**$ 43.38**	**$ 40.36**	**$ 39.20**	**$ 40.50**	$ 34.62	$ 35.54
Transportation	**3.06**	**2.97**	**3.27**	**3.24**	**3.14**	2.96	2.66
Realized sales price, net of transportation	**36.21**	**40.41**	**37.09**	**35.96**	**37.36**	31.66	32.88
Royalties	**3.78**	**4.06**	**4.07**	**4.37**	**4.09**	3.27	3.40
Production expense	**12.68**	**11.68**	**11.11**	**10.79**	**11.49**	12.71	11.95
Netback	**$ 19.75**	**$ 24.67**	**$ 21.91**	**$ 20.80**	**$ 21.78**	$ 15.68	$ 17.53

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

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING

	Q1	Q2	Q3	Q4	2019	2018	2017
Crude oil and NGLs ($/bbl) (1)							
SCO sales price (2)	**$ 65.86**	**$ 74.98**	**$ 71.60**	**$ 68.67**	**$ 70.18**	$ 68.61	$ 63.98
Bitumen royalties (3)	**2.31**	**3.79**	**3.76**	**3.47**	**3.31**	3.09	1.64
Transportation	**1.17**	**1.53**	**1.16**	**1.33**	**1.29**	1.61	1.54
Adjusted production costs	**21.46**	**24.17**	**18.82**	**23.02**	**21.75**	21.05	23.40
Netback	**$ 40.92**	**$ 45.49**	**$ 47.86**	**$ 40.85**	**$ 43.83**	$ 42.86	$ 37.40

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.
(2) Net of blending and feedstock costs.
(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2019	2018
TSX – C$						
Trading volume (thousands)	**241,284**	**216,340**	**226,800**	**219,589**	**904,013**	806,254
Share Price ($/share)						
High	**$ 38.45**	**$ 42.56**	**$ 38.00**	**$ 42.40**	**$ 42.56**	$ 49.08
Low	**$ 31.52**	**$ 34.25**	**$ 30.01**	**$ 32.26**	**$ 30.01**	$ 30.11
Close	**$ 36.69**	**$ 35.31**	**$ 35.25**	**$ 42.00**	**$ 42.00**	$ 32.94
Market capitalization as at December 31 ($ millions)					**$ 49,848**	$ 39,590
Shares outstanding (thousands)					**1,186,857**	1,201,886
NYSE – US$						
Trading volume (thousands)	**200,874**	**164,274**	**163,447**	**151,102**	**679,697**	796,971
Share Price ($/share)						
High	**$ 29.04**	**$ 31.77**	**$ 28.71**	**$ 32.56**	**$ 32.56**	$ 38.19
Low	**$ 23.09**	**$ 25.42**	**$ 22.58**	**$ 24.20**	**$ 22.58**	$ 21.85
Close	**$ 27.50**	**$ 26.97**	**$ 26.63**	**$ 32.35**	**$ 32.35**	$ 24.13
Market capitalization as at December 31 ($ millions)					**$ 38,395**	$ 29,002
Shares outstanding (thousands)					**1,186,857**	1,201,886

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, 2019, 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, 2019, 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, 2019, 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, 2019, 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 and Mr. W.A. Gobert each qualify 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 and Mr. W.A. Gobert are, 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. In 2019, the Code of Ethics was revised to incorporate the Company's third-party-operated whistleblower hotline information and to add an appendix addressing employees who choose to run for public office. Canadian Natural does not view these changes as being material.

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, 2019 and December 31, 2018, 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 $2,580,000 for 2019 and were $2,597,000 for 2018.

Audit-Related Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ended December 31, 2019 and December 31, 2018, for audit-related services by PwC including pension assets and Crown Royalty Statements were $536,000 for 2019 and were $425,000 for 2018. 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, 2019 and December 31, 2018, for professional services rendered by PwC for tax services related to expatriate personal tax compliance and other corporate tax return matters were $426,000 for 2019 and were $443,000 for 2018. 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, 2019 and December 31, 2018 for other services were $32,000 for 2019 and were $30,000 for 2018, 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, 2019:

($ millions)	2020	2021	2022	2023	2024	Thereafter
Product transportation and pipeline [1] [2]	$ 730	$ 722	$ 637	$ 726	$ 699	$ 7,907
North West Redwater Partnership debt service toll [3]	$ 133	$ 167	$ 157	$ 164	$ 156	$ 2,815
Offshore equipment operating leases	$ 69	$ 63	$ 9	$ —	$ —	$ —
Office leases	$ 27	$ 21	$ 20	$ 21	$ 20	$ 249
Other	$ 26	$ 20	$ 17	$ 17	$ 17	$ 30

(1) On June 27, 2019, the Company assumed $2,381 million of product transportation commitments related to the acquisition of assets from Devon.
(2) Includes commitments pertaining to a 20 year product transportation agreement on the Trans Mountain Pipeline Expansion. In addition, the Company has entered into certain product transportation agreements on pipelines that have not yet received regulatory and other approvals. The Company may be required to reimburse certain construction costs to the service provider under certain conditions.
(3) 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 tolls, which currently consists of interest and fees, with principal repayments beginning in 2020. Included in the cost of service tolls is $1,260 million of interest payable over the 30 year tolling period.

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. W.A. Gobert, G. D. Giffin, D. A. Tuer.

MINE SAFETY DISCLOSURE

Not Applicable.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

Undertaking

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

Consent to Service of Process

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

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

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 25th day of March, 2020.

CANADIAN NATURAL RESOURCES LIMITED

By: SIGNED “TIM S. MCKAY”
Name: Tim S. McKay
Title: President

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, 2019.
101	Interactive data files with respect to the consolidated financial statements for the fiscal year ended December 31, 2019.

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm



Consent of Independent Registered Public Accounting Firm

We hereby consent to the inclusion in this Annual Report on Form 40-F for the year ended December 31, 2019 of Canadian Natural Resources Limited, of our report dated March 18, 2020, relating to the consolidated financial statements, and the effectiveness of internal control over financial reporting, which appears in this Annual Report.

We also consent to the incorporation by reference in the Registration Statement on Form F-10 (SEC file number 333-232692) of Canadian Natural Resources Limited of our report dated March 18, 2020 referred to above. We also consent to reference to us under the heading “Interests of Experts,” which appears in the Annual Information Form included in this Annual Report on Form 40-F, which is incorporated by reference in such registration statement.

SIGNED "PricewaterhouseCoopers LLP"

Chartered Professional Accountants

Calgary, Canada
March 27, 2020

PricewaterhouseCoopers LLP
111 5 Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825, www.pwc.com/ca

“PwC” refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.

EXHIBIT 23.2

Consent of Sproule Associates Limited,
Independent Petroleum Engineering Consultants



LETTER OF CONSENT

Canadian Natural Resources Limited
2100, 855 - 2nd Street SW
CALGARY AB T2P 4J8

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

We consent to the use of our name and our report with respect to the reserves data of Canadian Natural Resources Limited (the "Company"), and the information derived from our report, included and incorporated by reference in the Company's

(i) Annual Report on Form 40-F for the year ended December 31, 2019 and

(ii) Registration Statement on Form F-10 (File No. 333-232692) filed with the Securities and Exchange Commission.

Sincerely,

SPROULE ASSOCIATES LIMITED
Original Signed by
SIGNED "STEVEN J. GOLKO"
Steven J. Golko, P.Eng.
Senior Vice President

Calgary, Alberta, Canada

March 27, 2020

140 Fourth Avenue SW, Suite 900
Calgary, AB, Canada T2P 3N3
Sproule.com
T +1 403 294 5500 F +1 403 294 5590 TF +1 877 777 6135

EXHIBIT 23.3

Consent of Sproule Associates Limited,
Independent Petroleum Engineering Consultants



LETTER OF CONSENT

Canadian Natural Resources Limited
2100, 855 - 2nd Street SW
CALGARY AB T2P 4J8

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

We consent to the use of our name and our reports with respect to the reserves data of Canadian Natural Resources Limited (the "Company"), and the information derived from our reports, included and incorporated by reference in the Company's

(i) Annual Report on Form 40-F for the year ended December 31, 2019 and

(ii) Registration Statement on Form F-10 (File No. 333-232692) filed with the Securities and Exchange Commission.

Sincerely,

SPROULE INTERNATIONAL LIMITED
Original Signed by
SIGNED "SCOTT W. PENNELL"
Scott W. Pennell, P.Eng.
Chief Operating Officer

Calgary, Alberta, Canada

March 27, 2020

140 Fourth Avenue SW, Suite 900
Calgary, AB, Canada T2P 3N3
Sproule.com
T +1 403 294 5500 F +1 403 294 5590 TF +1 877 777 6135

EXHIBIT 23.4

Consent of GLJ Petroleum Consultants Ltd.,
Independent Petroleum Engineering Consultants

LETTER OF CONSENT

Canadian Natural Resources Limited
2100, 855 - 2nd Street SW
CALGARY AB T2P 4J8

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

We consent to the use of our name and our reports with respect to the reserves data of Canadian Natural Resources Limited (the "Company"), and the information derived from our reports, included and incorporated by reference in the Company's

(i) Annual Report on Form 40-F for the year ended December 31, 2019 and

(ii) Registration Statement on Form F-10 (File No. 333-232692) filed with the Securities and Exchange Commission.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.
"Originally Signed by"
Tim R. Freeborn, P. Eng.
Vice President and Chief Financial Officer

Calgary, Alberta, Canada
March 27, 2020

EXHIBIT 31.1

Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a)

of the Securities Exchange Act of 1934

CERTIFICATION

I, Tim S. McKay, certify that:

1. I have reviewed this annual report on Form 40-F of Canadian Natural Resources Limited;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;
4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and
5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated this 27th day of March, 2020.

SIGNED "TIM S. MCKAY"
Tim S. McKay
President (Principal Executive Officer),
Canadian Natural Resources Limited

EXHIBIT 31.2

Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a)

of the Securities Exchange Act of 1934

CERTIFICATION

I, Mark A. Stainthorpe, certify that:

1. I have reviewed this annual report on Form 40-F of Canadian Natural Resources Limited;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;
4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and
5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated this 27th day of March, 2020.

SIGNED "MARK A. STAINTHORPE"
Mark A. Stainthorpe
Chief Financial Officer and Senior Vice-President, Finance (Principal Financial Officer),
Canadian Natural Resources Limited

EXHIBIT 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)

In connection with the Annual Report of Canadian Natural Resources Limited (the "Company") on Form 40-F for the fiscal year ending December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Tim S. McKay, certify pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

DATED this 27th day of March, 2020.

SIGNED "TIM S. MCKAY"
Tim S. McKay
President (Principal Executive Officer),
Canadian Natural Resources Limited

EXHIBIT 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)

In connection with the Annual Report of Canadian Natural Resources Limited (the "Company") on Form 40-F for the fiscal year ending December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Mark A. Stainthorpe, certify pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

DATED this 27th day of March, 2020.

SIGNED "MARK A. STAINTHORPE"
Mark A. Stainthorpe
Chief Financial Officer and Senior Vice-President, Finance (Principal Financial Officer),
Canadian Natural Resources Limited

EXHIBIT 99.1

Supplementary Oil & Gas Information for the Fiscal Year Ended December 31, 2019 (Unaudited)

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

For the years ended December 31, 2019, 2018, 2017 and 2016 the Company filed its reserves information under National Instrument 51-101 – "Standards of Disclosure of Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada.

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

For the purposes of determining proved crude oil and natural gas reserves for SEC requirements as at December 31, 2019, 2018, 2017 and 2016 the Company used the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The Company has used the following 12-month average benchmark prices to determine its 2019 reserves for SEC requirements.

Crude Oil and NGLs						Natural Gas		
WTI Cushing Oklahoma	WCS	Canadian Light Sweet	Cromer LSB	North Sea Brent	Edmonton C5+	Henry Hub Louisiana	AECO	BC Westcoast Station 2
(US$/bbl)	(C$/bbl)	(C$/bbl)	(C$/bbl)	(US$/bbl)	(C$/bbl)	(US$/MMBtu)	(C$/MMBtu)	(C$/MMBtu)
55.73	57.29	66.77	66.85	62.54	68.71	2.54	2.02	1.13

A foreign exchange rate of US$1.00/C$1.3297 was used in the 2019 evaluation, determined on the same basis as the 12-month average price.

Net Proved Crude Oil and Natural Gas Reserves

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

- For the years ended December 31, 2019, 2018, 2017 and 2016, the reports by GLJ Petroleum Consultants Ltd. covered 100% of the Company's SCO reserves. With the inclusion of non-traditional resources within the definition of "oil and gas producing activities" in the SEC's modernization of oil and gas reporting rules, effective January 1, 2010 these reserves volumes are included within the Company's crude oil and natural gas reserves totals.
- For the years ended December 31, 2019, 2018, 2017 and 2016, the reports by Sproule Associates Limited and Sproule International Limited covered 100% of the Company's crude oil, bitumen, natural gas and NGLs reserves.

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

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

The following tables summarize the Company's proved and proved developed crude oil and natural gas reserves, net of royalties, as at December 31, 2019, 2018, 2017 and 2016:

	North America						
Crude Oil and NGLs (MMbbl)[1]	**Synthetic Crude Oil**	**Bitumen**[2]	**Crude Oil & NGLs**	**North America Total**	**North Sea**	**Offshore Africa**	**Total**
Net Proved Reserves							
Reserves, December 31, 2016	2,542	1,301	504	4,347	93	74	4,514
Extensions and discoveries	—	28	17	45	—	—	45
Improved recovery	—	7	19	26	1	—	27
Purchases of reserves in place	2,232	37	67	2,336	—	—	2,336
Sales of reserves in place	—	—	—	—	—	—	—
Production	(100)	(70)	(44)	(214)	(9)	(6)	(229)
Economic revisions due to prices	—	18	17	35	18	1	54
Revisions of prior estimates	282	44	14	340	4	—	344
Reserves, December 31, 2017	4,956	1,365	594	6,915	107	69	7,091
Extensions and discoveries	744	151	17	912	—	—	912
Improved recovery	—	10	50	60	1	3	64
Purchases of reserves in place	—	2	7	9	7	—	16
Sales of reserves in place	—	(4)	—	(4)	—	—	(4)
Production	(148)	(64)	(47)	(259)	(9)	(6)	(274)
Economic revisions due to prices	—	(45)	(18)	(63)	11	1	(51)
Revisions of prior estimates	109	54	1	164	(3)	4	165
Reserves, December 31, 2018	5,661	1,469	604	7,734	114	71	7,919
Extensions and discoveries	**334**	**18**	**12**	**364**	**—**	**—**	**364**
Improved recovery	**—**	**169**	**12**	**181**	**—**	**—**	**181**
Purchases of reserves in place	**—**	**666**	**2**	**668**	**—**	**—**	**668**
Sales of reserves in place	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Production	**(137)**	**(81)**	**(49)**	**(267)**	**(10)**	**(7)**	**(285)**
Economic revisions due to prices[3]	**(288)**	**3**	**—**	**(285)**	**(1)**	**1**	**(285)**
Revisions of prior estimates	**(17)**	**(27)**	**17**	**(28)**	**3**	**6**	**(19)**
Reserves, December 31, 2019	**5,554**	**2,216**	**598**	**8,368**	**105**	**70**	**8,544**
Net proved developed reserves							
December 31, 2016	2,527	384	353	3,264	12	31	3,307
December 31, 2017	4,967	410	399	5,776	28	21	5,825
December 31, 2018	5,661	461	378	6,500	37	34	6,571
December 31, 2019	**5,452**	**661**	**354**	**6,466**	**38**	**39**	**6,543**

(1) Information in the reserves data tables may not add due to rounding.

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

(3) Reflects the impact of increased royalties at Oil Sands Mining and Upgrading (SCO) due to higher Bitumen pricing resulting in higher royalties and lower net reserves.

2019 total proved Crude Oil and NGLs reserves increased by 625 MMbbl:

- Extensions and discoveries: Increase of 364 MMbbl primarily due to the transfer of reserves from the probable category at Oil Sands Mining and Upgrading (SCO) and extension drilling/future offset additions at various Bitumen, Crude Oil and natural gas (NGLs) properties.
- Improved recovery: Increase of 181 MMbbl primarily due to increased steamflood recovery at the Primrose thermal oil (Bitumen) project.
- Purchases of reserves in place: Increase of 668 MMbbl primarily due to Bitumen property acquisitions from Devon Canada.
- Production: Decrease of 285 MMbbl.
- Economic revisions due to prices: Decrease of 285 MMbbl primarily at Oil Sands Mining and Upgrading (SCO) due to higher Bitumen pricing resulting in higher royalties and lower net reserves.
- Revisions of prior estimates: Decrease of 19 MMbbl primarily due to the 50-year reserves life cutoff at the Primrose thermal oil (Bitumen) project, increased royalties at Oil Sands Mining and Upgrading (SCO) as a result of lower operating costs, and the removal of future extension and infill undeveloped reserves in certain Crude Oil and Bitumen properties because of revised Company development plans, offset by improved performance at the Pelican Lake (Crude Oil) project and various natural gas (NGLs) properties.

2018 total proved Crude Oil and NGLs reserves increased by 828 MMbbl primarily due to the following:

- Extensions and discoveries: Increase of 912 MMbbl primarily due to the addition of the Horizon South Pit to the Horizon oil sands mining and upgrading Project ("Horizon") (SCO), future thermal (Bitumen) well pad additions at Primrose and extension drilling/future offset additions at various primary heavy crude oil (Bitumen), Crude Oil and natural gas (NGLs) properties.
- Improved recovery: Increase of 64 MMbbl primarily due to infill drilling/future offset additions at various primary heavy crude oil (Bitumen), thermal (Bitumen), Crude Oil and natural gas (NGLs) properties as well as thermal (Bitumen) improved recovery additions.
- Purchases of reserves in place: Increase of 16 MMbbl primarily due to property acquisitions in North America and North Sea core areas.
- Sales of reserves in place: Decrease of 4 MMbbl from the primary heavy crude oil (Bitumen) area.
- Production: Decrease of 274 MMbbl.
- Economic revisions due to prices: Decrease of 51 MMbbl primarily due to increased royalties at thermal (Bitumen) and Pelican Lake (Crude Oil) projects resulting from higher prices and uneconomic reserves at several North America natural gas (NGLs) core areas, partially offset by improved reserve life economics at the North Sea.
- Revisions of prior estimates: Increase of 165 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).

2017 total proved Crude Oil and NGLs reserves increased by 2,577 MMbbl primarily due to the following:

- Extensions and discoveries: Increase of 45 MMbbl primarily due to future thermal (Bitumen) well pad additions at Primrose and extension drilling/future offset additions at various primary heavy crude oil (Bitumen), Crude Oil and natural gas (NGLs) properties.
- Improved recovery: Increase of 27 MMbbl primarily due to infill drilling/future offset additions at various primary heavy crude oil (Bitumen) and Crude Oil and natural gas (NGLs) properties.
- Purchases of reserves in place: Increase of 2,336 MMbbl due to acquisitions of the Athabasca Oil Sands Project (SCO), Peace River thermal and Cliffdale primary heavy crude oil properties (Bitumen) and at Pelican Lake (Crude Oil).
- Production: Decrease of 229 MMbbl.
- Economic revisions due to prices: Increase of 54 MMbbl primarily due to improved reserves life economics at several North America Bitumen and Crude Oil core areas.
- Revisions of prior estimates: Increase of 344 MMbbl primarily due to Horizon (SCO) revising the stratigraphic well density used to define proved reserves quantities and increasing the Horizon (SCO) total-volume-to-bitumen-in-place-ratio, partially offset by Horizon (SCO) adopting a low fines mine plan. Additionally, there were overall positive revisions at several North America Bitumen and Crude Oil core areas including improved recoveries at Primrose (Bitumen).

Natural Gas (Bcf)(1)	North America	North Sea	Offshore Africa	Total
Net Proved Reserves				
Reserves, December 31, 2016	4,594	25	25	4,644
Extensions and discoveries	261	—	—	261
Improved recovery	179	—	—	179
Purchases of reserves in place	106	—	—	106
Sales of reserves in place	—	—	—	—
Production	(558)	(14)	(7)	(579)
Economic revisions due to prices	403	5	(1)	407
Revisions of prior estimates	214	9	(1)	222
Reserves, December 31, 2017	5,199	25	16	5,240
Extensions and discoveries	90	—	—	90
Improved recovery	414	—	—	414
Purchases of reserves in place	67	—	—	67
Sales of reserves in place	(3)	—	—	(3)
Production	(523)	(11)	(8)	(542)
Economic revisions due to prices	(746)	—	(2)	(748)
Revisions of prior estimates	(192)	13	15	(164)
Reserves, December 31, 2018	4,306	27	21	4,354
Extensions and discoveries	**106**	**—**	**—**	**106**
Improved recovery	**202**	**—**	**—**	**202**
Purchases of reserves in place	**34**	**—**	**—**	**34**
Sales of reserves in place	**—**	**—**	**—**	**—**
Production	**(511)**	**(9)**	**(8)**	**(528)**
Economic revisions due to prices	**246**	**—**	**2**	**248**
Revisions of prior estimates	**346**	**(2)**	**23**	**367**
Reserves, December 31, 2019	**4,728**	**16**	**38**	**4,782**
Net proved developed reserves				
December 31, 2016	2,805	18	18	2,841
December 31, 2017	3,081	22	9	3,112
December 31, 2018	2,382	23	12	2,417
December 31, 2019	**2,342**	**11**	**28**	**2,381**

(1) Information in the reserves data tables may not add due to rounding.

2019 total proved Natural Gas reserves increased by 428 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 106 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 202 Bcf primarily due to infill drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 34 Bcf primarily due to property acquisitions in several North America core areas.
- Production: Decrease of 528 Bcf.
- Economic revisions due to prices: Increase of 248 Bcf primarily due to increased Natural Gas price in North America.
- Revisions of prior estimates: Increase of 367 Bcf primarily due to overall positive revisions in several North America and Offshore Africa core areas as a result of increased recovery and category transfers from probable to proved. The increase is also due to improved economics on undeveloped reserves which, when combined with lower long term royalty rates, results in increased net, after royalties, reserves.

2018 total proved Natural Gas reserves decreased by 886 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 90 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 414 Bcf primarily due to infill drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 67 Bcf primarily due to property acquisitions in several North America core areas.
- Sales of reserves in place: Decrease of 3 Bcf.
- Production: Decrease of 542 Bcf.
- Economic revisions due to prices: Decrease of 748 Bcf due to uneconomic reserves at several North America Natural Gas core areas.
- Revisions of prior estimates: Decrease of 164 Bcf primarily due to the removal of future extension and infill undeveloped reserves at several North America properties as a result of revised Company development plans.

2017 total proved Natural Gas reserves increased by 596 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 261 Bcf primarily due to extension drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 179 Bcf primarily due to infill drilling/future offset additions in the Montney and Spirit River formations of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 106 Bcf primarily due to property acquisitions in several North America core areas.
- Production: Decrease of 579 Bcf.
- Economic revisions due to prices: Increase of 407 Bcf due to improved reserves life economics at several North America Natural Gas core areas.
- Revisions of prior estimates: Increase of 222 Bcf primarily due to overall positive revisions at several North America core areas triggered by production optimizations and reduced production costs.

Capitalized Costs Related to Crude Oil and Natural Gas Activities

(millions of Canadian dollars)	2019 North America	North Sea	Offshore Africa	Total
Proved properties	**$ 117,643**	**$ 7,296**	**$ 3,933**	**$ 128,872**
Unproved properties	**2,510**	**—**	**69**	**2,579**
	120,153	**7,296**	**4,002**	**131,451**
Less: accumulated depletion and depreciation	**(52,824)**	**(5,712)**	**(2,712)**	**(61,248)**
Net capitalized costs	**$ 67,329**	**$ 1,584**	**$ 1,290**	**$ 70,203**

(millions of Canadian dollars)	2018 North America	North Sea	Offshore Africa	Total
Proved properties	$ 110,154	$ 7,321	$ 5,471	$ 122,946
Unproved properties	2,600	—	37	2,637
	112,754	7,321	5,508	125,583
Less: accumulated depletion and depreciation	(48,862)	(5,735)	(4,203)	(58,800)
Net capitalized costs	$ 63,892	$ 1,586	$ 1,305	$ 66,783

(millions of Canadian dollars)	2017 North America	North Sea	Offshore Africa	Total
Proved properties	$ 106,900	$ 7,126	$ 4,881	$ 118,907
Unproved properties	2,541	—	91	2,632
	109,441	7,126	4,972	121,539
Less: accumulated depletion and depreciation	(44,779)	(5,653)	(3,719)	(54,151)
Net capitalized costs	$ 64,662	$ 1,473	$ 1,253	$ 67,388

Costs Incurred in Crude Oil and Natural Gas Activities

(millions of Canadian dollars)	2019 North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 3,405	$ —	$ —	$ 3,405
Unproved	91	—	—	91
Exploration	38	—	33	71
Development	4,687	349	233	5,269
Costs incurred	$ 8,221	$ 349	$ 266	$ 8,836

(millions of Canadian dollars)	2018 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
Costs incurred	$ 3,915	$ 237	$ 158	$ 4,310

(millions of Canadian dollars)	2017 North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 15,091	$ —	$ —	$ 15,091
Unproved	321	—	—	321
Exploration	112	—	15	127
Development	3,753	255	101	4,109
Costs incurred	$ 19,277	$ 255	$ 116	$ 19,648

Results of Operations from Crude Oil and Natural Gas Producing Activities

The Company's results of operations from crude oil and natural gas producing activities for the years ended December 31, 2019, 2018 and 2017 are summarized in the following tables:

	2019			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	**$ 17,348**	**$ 920**	**$ 676**	**$ 18,944**
Production	**(5,701)**	**(391)**	**(109)**	**(6,201)**
Transportation	**(968)**	**(19)**	**(2)**	**(989)**
Depletion, depreciation and amortization	**(4,982)**	**(308)**	**(242)**	**(5,532)**
Asset retirement obligation accretion	**(156)**	**(28)**	**(6)**	**(190)**
Petroleum revenue tax	**—**	**88**	**—**	**88**
Income tax	**(1,468)**	**(105)**	**(79)**	**(1,652)**
Results of operations	**$ 4,073**	**$ 157**	**$ 238**	**$ 4,468**

	2018			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	$ 16,065	$ 891	$ 647	$ 17,603
Production	(5,772)	(405)	(208)	(6,385)
Transportation	(929)	(22)	(2)	(953)
Depletion, depreciation and amortization	(4,689)	(257)	(201)	(5,147)
Asset retirement obligation accretion	(148)	(29)	(9)	(186)
Petroleum revenue tax	—	12	—	12
Income tax	(1,223)	(76)	(51)	(1,350)
Results of operations	$ 3,304	$ 114	$ 176	$ 3,594

	2017			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	$ 13,083	$ 784	$ 578	$ 14,445
Production	(4,962)	(400)	(226)	(5,588)
Transportation	(790)	(31)	(1)	(822)
Depletion, depreciation and amortization	(4,463)	(509)	(205)	(5,177)
Asset retirement obligation accretion	(128)	(27)	(9)	(164)
Petroleum revenue tax	—	78	—	78
Income tax	(740)	42	(28)	(726)
Results of operations	$ 2,000	$ (63)	$ 109	$ 2,046

Standardized Measure of Discounted Future Net Cash Flows from Proved Crude Oil and Natural Gas Reserves and Changes Therein

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

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

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

	2019			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Future cash inflows	**$ 515,864**	**$ 10,030**	**$ 5,858**	**$ 531,752**
Future production costs	**(194,076)**	**(4,893)**	**(2,081)**	**(201,050)**
Future development costs and asset retirement obligations	**(70,879)**	**(2,648)**	**(1,076)**	**(74,603)**
Future income taxes	**(53,759)**	**(936)**	**(547)**	**(55,242)**
Future net cash flows	**197,150**	**1,553**	**2,154**	**200,857**
10% annual discount for timing of future cash flows	**(136,616)**	**(1)**	**(715)**	**(137,332)**
Standardized measure of future net cash flows	**$ 60,534**	**$ 1,552**	**$ 1,439**	**$ 63,525**

	2018			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Future cash inflows	$ 500,557	$ 12,002	$ 6,447	$ 519,006
Future production costs	(193,387)	(5,148)	(2,284)	(200,819)
Future development costs and asset retirement obligations	(63,202)	(2,909)	(1,099)	(67,210)
Future income taxes	(60,526)	(1,484)	(626)	(62,636)
Future net cash flows	183,442	2,461	2,438	188,341
10% annual discount for timing of future cash flows	(126,699)	(545)	(771)	(128,015)
Standardized measure of future net cash flows	$ 56,743	$ 1,916	$ 1,667	$ 60,326

	2017			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Future cash inflows	$ 413,180	$ 8,740	$ 4,786	$ 426,706
Future production costs	(198,304)	(4,168)	(1,876)	(204,348)
Future development costs and asset retirement obligations	(61,169)	(2,853)	(1,258)	(65,280)
Future income taxes	(35,645)	(595)	(248)	(36,488)
Future net cash flows	118,062	1,124	1,404	120,590
10% annual discount for timing of future cash flows	(73,171)	(59)	(455)	(73,685)
Standardized measure of future net cash flows	$ 44,891	$ 1,065	$ 949	$ 46,905

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

(millions of Canadian dollars)	**2019**	2018	2017
Sales of crude oil and natural gas produced, net of production costs	**$ (11,807)**	$ (10,229)	$ (8,013)
Net changes in sales prices and production costs	**(3,515)**	20,386	7,466
Extensions, discoveries and improved recovery	**5,883**	2,807	481
Changes in estimated future development costs	**(1,889)**	(698)	(5,548)
Purchases of proved reserves in place	**7,418**	396	25,782
Sales of proved reserves in place	**—**	(55)	—
Revisions of previous reserve estimates	**(3,384)**	2,711	4,245
Accretion of discount	**8,062**	6,119	3,075
Changes in production timing and other	**447**	(955)	(662)
Net change in income taxes	**1,984**	(7,061)	(4,236)
Net change	**3,199**	13,421	22,590
Balance - beginning of year	**60,326**	46,905	24,315
Balance - end of year	**$ 63,525**	$ 60,326	$ 46,905