Canadian Natural

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	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
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	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
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	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	**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	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
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	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
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	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	**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 (40° API), low sulphur content Mixed Sweet Blend (MSW) crude oil at Edmonton, Alberta; reference price used in the preparation of light and medium crude oil and SCO reserves.
   - "Cromer LSB" refers to the price of light sour blend (35° API) physical crude oil at Cromer, Manitoba; reference price used in the preparation of light and medium crude oil in SE Saskatchewan and SW Manitoba reserves.
   - "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.

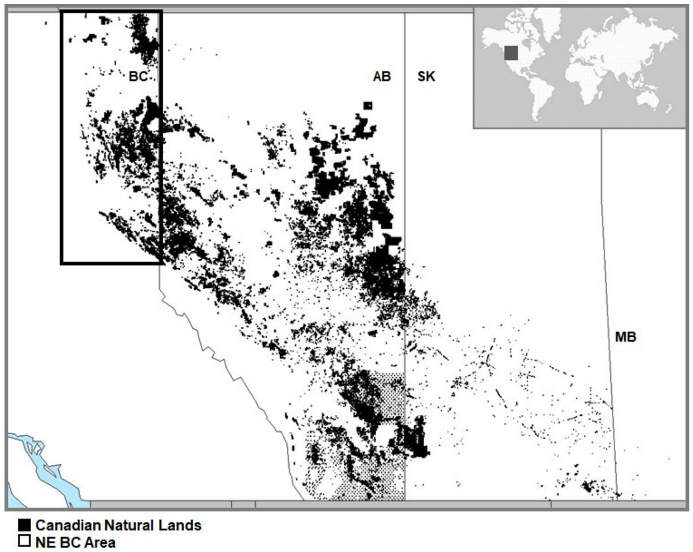
Other Oil and Gas Information

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.

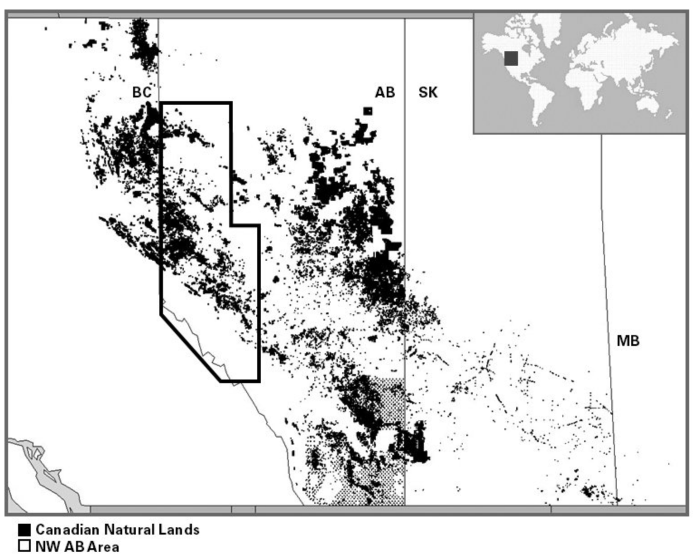
	2019 Average Daily Production Rates		2018 Average Daily Production Rates	
Region	**Crude Oil & NGLs (Mbbl)**	**Natural Gas (MMcf)**	Crude Oil & NGLs (Mbbl)	Natural Gas (MMcf)
North America				
Northeast British Columbia	**13**	**346**	13	345
Northwest Alberta	**52**	**675**	46	667
Northern Plains	**317**	**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



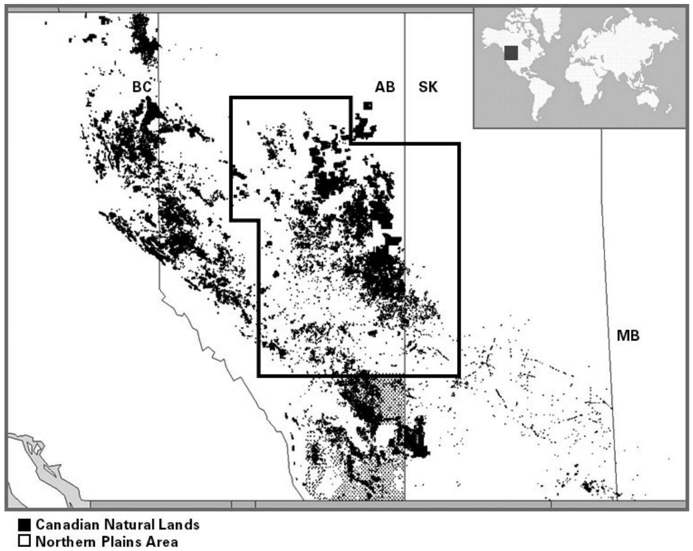
The Northeast British Columbia Region holds a significant portion of the Montney formation. This formation produces liquids rich natural gas and light oil from several stratigraphic intervals. The exploration strategy focuses on comprehensive evaluation through two dimensional seismic, three dimensional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

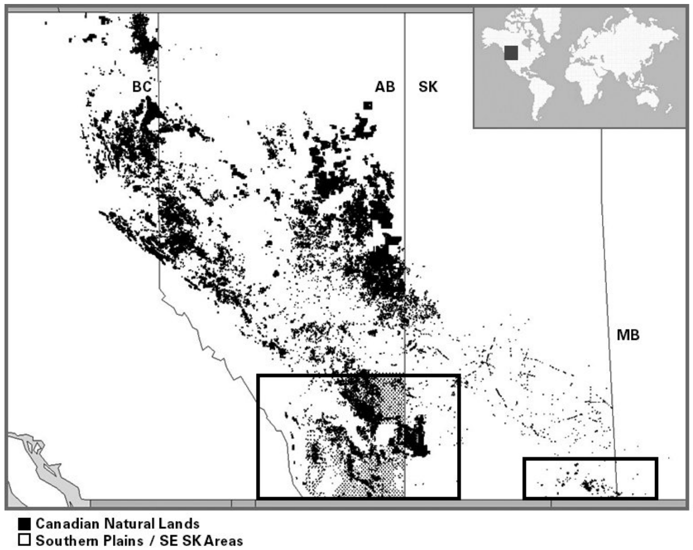
Production of bitumen (thermal oil) from the 100% owned Primrose and Wolf Lake Fields located near Bonnyville, Alberta, involves processes that utilize steam to increase the recovery of the bitumen. The processes employed by the Company are CSS, SAGD and steamflood. These recovery processes inject steam 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

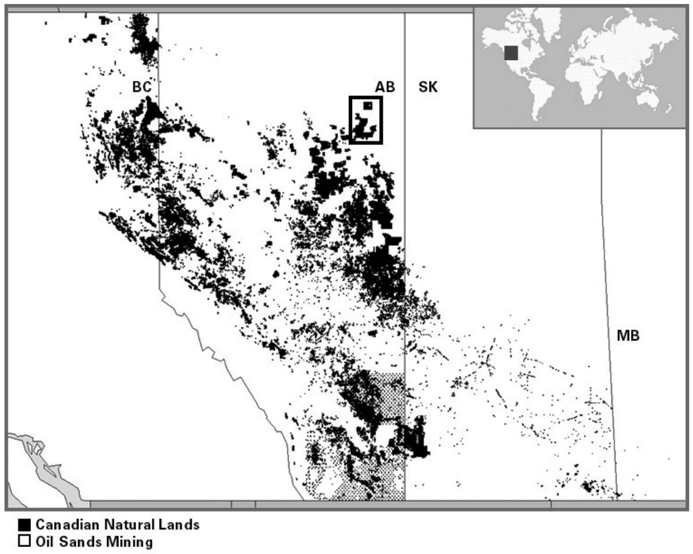


The Southern Plains region is principally located south of the Northern Plains region to the United States border and extending into western Saskatchewan.

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.

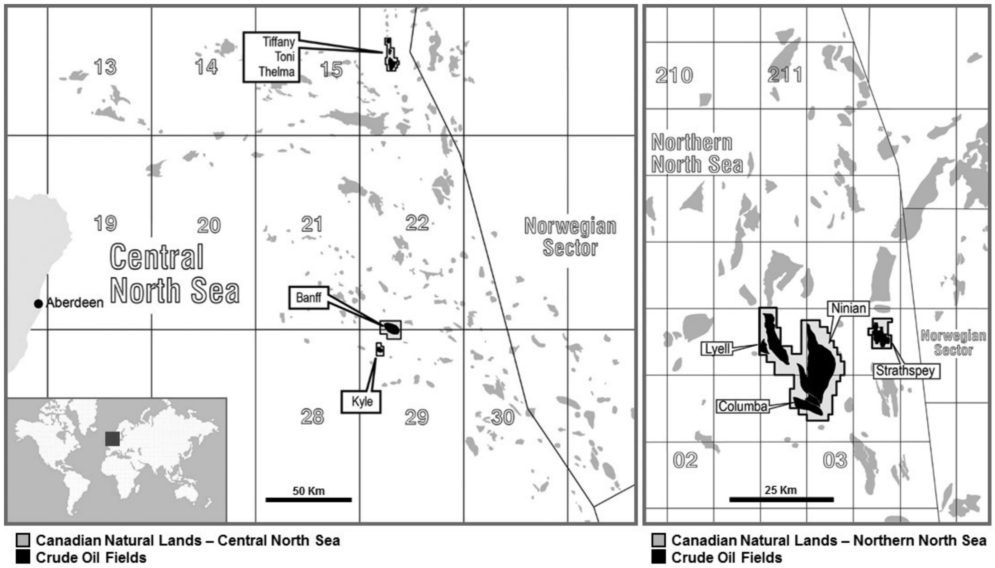
In the third quarter of 2018, the Company acquired the Joslyn oil sands project, adding to the Company's total oil sands mining and upgrading reserves. This incorporation of the Joslyn leases (now, Horizon South) to the mine plan will allow mining to continue south of the previously existing Horizon 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.

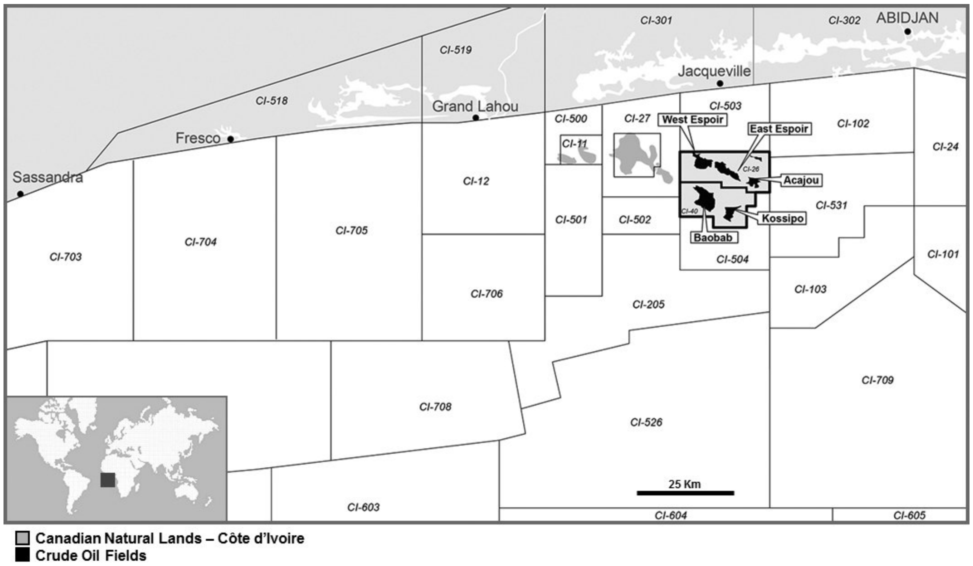
The Company receives tariff revenue from other field owners for the processing of crude oil and natural gas through certain processing facilities.

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

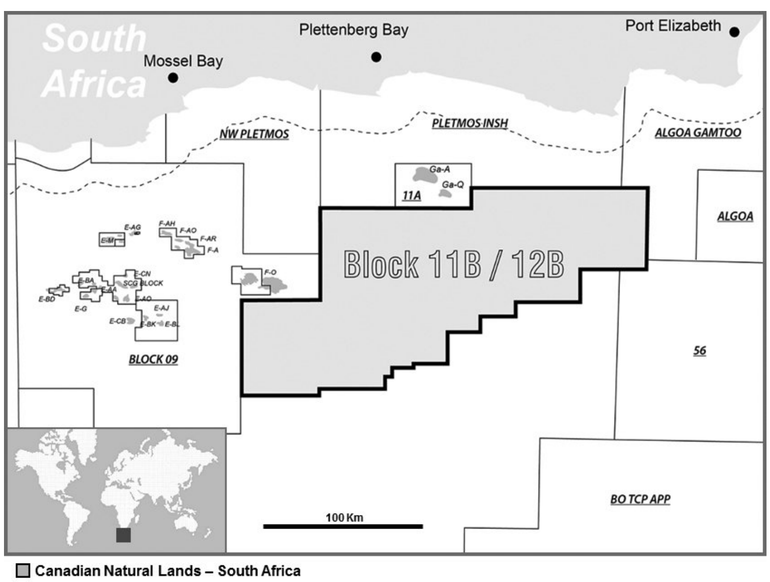


The Company owns interests in two licences offshore Côte d'Ivoire.

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.