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

FORM 40-F

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

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

For the fiscal year ended December 31, 2021 Commission File Number: 001-12138

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

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

1311
(Primary Standard Industrial Classification Code Numbers)

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

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

CT Corporation System, 28 Liberty Street, New York, New York 10005
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code)
of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

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

Securities registered or to be registered pursuant to Section 12(g) of the Act: None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: None

For annual reports, indicate by check mark the information filed with this Form:

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

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

1,168,369,000 Common Shares outstanding as of December 31, 2021

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

Yes [X] No [ ]

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

Yes [X] No [ ]

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging Growth Company [___]

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

[___]

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

Yes [X] No [ ]

† The term new or revised financial accounting standard refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

This Annual Report on Form 40-F shall be incorporated by reference into, or as an exhibit to, as applicable, the Registrant's Registration Statement on Form F-10 (File No. 333-258127) under the Securities Act of 1933, as amended.

PRINCIPAL DOCUMENTS

The following documents have been filed as part of this Annual Report on Form 40-F, starting on the following page:

A. Annual Information Form

Annual Information Form of Canadian Natural Resources Limited ("Canadian Natural") for the year ended December 31, 202 1.

B. Audited Annual Financial Statements

Canadian Natural's audited consolidated financial statements for the years ended December 31, 202 1 and 2020, including the report of independent registered public accounting firm (PCAOB ID 271) with respect thereto.

C. Management's Discussion and Analysis

Canadian Natural's Management's Discussion and Analysis for the year ended December 31, 202 1.

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

A. Supplementary Oil & Gas Information (Unaudited)

For Canadian Natural's Supplementary Oil & Gas Information (Unaudited) for the year ended December 31, 202 1, see Exhibit 99.1 to this Annual Report on Form 40-F.



CANADIAN NATURAL RESOURCES LIMITED

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2021

March 23, 2022

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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
IASB	International Accounting Standards Board
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
net zero	refers to emissions (scope 1 and scope 2) from oil sands operations
NYSE	New York Stock Exchange
OPEC+	Organization of Petroleum Exporting Countries Plus
Paris Agreement	The Paris Agreement is an agreement within the United Nations Framework Convention on Climate Change, on climate change mitigation, adaption, and finance signed in 2016.
Pathways	Oil Sands Pathways to Net Zero initiative is an alliance of oil sands producers, working collectively with federal and provincial governments, to achieve net zero GHG emissions from oil sands operations by 2050. All net-zero references herein apply to emissions from oil sands operations (defined as scope 1 and scope 1 emissions).
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” or "Canadian Natural") 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 targets 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 operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, 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, the "2022 Activity" section of this AIF with respect to budgeted capital expenditures for 2022, the timing and impact of the Oil Sands Pathways to Net Zero ("Pathways") initiative, government support for Pathways and the ability to achieve net zero emissions from oil production; targeted International decommissioning activities and the timing thereof; and the Company's targeted publication of its 2021 Stewardship Report to Shareholders in the third quarter of 2022, 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 effects resulting from the coronavirus ("COVID-19") pandemic and the actions of OPEC+) which may impact, among other things, demand and supply for and market prices of the Company’s products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil, and natural gas and NGLs prices including due to actions of OPEC+ taken in response to COVID-19 or otherwise; fluctuations in currency and interest rates; assumptions on which the Company’s current targets are based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company’s defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company’s and its subsidiaries’ ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting or upgrading of the Company’s bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company’s bitumen products; availability and cost of financing; the Company’s and its subsidiaries’ success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; 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 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 or 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 ratio may be misleading as an indication of value.

The comparative Consolidated Financial Statements and the Company's MD&A for the most recently completed fiscal year ended December 31, 2021, are herein incorporated by reference, and certain information included in this AIF, have been prepared in accordance with IFRS, as issued by the IASB.

For the year ended December 31, 2021, the Company retained Independent Qualified Reserves Evaluators ("IQRE"), Sproule Associates Limited and Sproule International Limited (together, "Sproule") and GLJ Ltd. ("GLJ"), to evaluate and review all of the Company's proved and proved plus probable reserves with an effective date of December 31, 2021 and a preparation date of February 7, 2022. 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 2021 Annual Report, 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; netback; and net capital expenditures. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP financial measures, as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure ("NI 52-112"). Non-GAAP measures are used by the Company to evaluate its financial performance, financial position or cash flow. Descriptions of the Company's non-GAAP measures "adjusted net earnings from operations," "adjusted funds flow," "netback," and "net capital expenditures," included in this AIF, are provided in the "Non-GAAP and Other Financial Measures" section of the Company's annual MD&A for the year ended December 31, 2021, dated March 2, 2022.

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 (Alberta) on January 6,1982 and was further continued under the Business Corporations Act (Alberta) on November 6,1985. Since that time, the Company has completed a number of transactions which have resulted in amalgamations, arrangements and amendments to constating documents, none of which have resulted in material changes thereto.

In the last ten years, the Company has amalgamated pursuant to the Business Corporations Act (Alberta) under the name Canadian Natural Resources Limited with the following:

- 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.
- October 1, 2020 - CNRL Upgrading Limited
- January 1, 2021 - Painted Pony Energy Ltd.
- January 1, 2022 - Storm Resources Ltd.; Storm Gas Resource Corp.; CNR Montney Ltd.

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 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.) Developments 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
CNR Petro Resources Limited	Alberta	100
Partnership		
Canadian Natural Resources	Alberta	100
Canadian Natural Resources Northern Alberta Partnership	Alberta	100
Canadian Natural Resources 2005 Partnership	Alberta	100
CNR Montney Partnership	Alberta	100

Canadian Natural, as the managing partner, CNR (ECHO) Resources Inc. and Canadian Natural Resources 2005 Partnership are the partners of Canadian Natural Resources, a general partnership. Canadian Natural, as the managing partner, CNR (ECHO) Resources Inc., Canadian Natural Resources and Canadian Natural Resources 2005 Partnership are partners of Canadian Natural Resources Northern Alberta Partnership, a general partnership. Canadian Natural, as the managing partner, and CNR (ECHO) Resources Inc. are the partners of Canadian Natural Resources 2005 Partnership, a general partnership. Canadian Natural, as the managing partner, and CNR Petro Resources Limited, are partners of CNR Montney Partnership, a general partnership.

In the ordinary course of business, Canadian Natural restructures its subsidiaries and partnerships to maintain efficient operations. The consolidated financial statements of Canadian Natural include the accounts of the Company and all of its subsidiaries and wholly-owned partnerships as well as certain of the Company's activities which are conducted through joint arrangements.

General Development of the Business

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 was 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 was undeveloped. To finance the acquisition, the Company entered into a three year $3,250 million committed term credit facility (the ”Devon 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 allowed 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 expired in August 2021, replacing the Company’s previously filed base shelf prospectuses that would have expired in August 2019.

2020

The government of Alberta's mandatory curtailment policy of crude oil and bitumen production initially imposed in 2018 was extended to December 31, 2021, due to ongoing delays to pipeline development. However, due to the COVID-19 pandemic and the resulting economic downturn, the government of Alberta advised that it would only put monthly production limits in effect if emerging market conditions made it absolutely necessary. Since December 1, 2020, there have been no monthly production limits.

Economic conditions worsened in March of 2020 as a result of the drop in global oil demand triggered by the spread of COVID-19, and a breakdown in negotiations between OPEC+ countries in the spring of 2020 in relation to output cuts intended to stem the volatility and drop in crude oil prices.

In 2020, the Company made further adjustments to its debt financing program. In the second quarter, the Company increased the $750 million non-revolving term credit facility to $1,000 million and extended the term from February 2021 to February 2022, which was extended subsequent to year end to February 2023. The Company also repaid $162.5 million of the Devon Credit Facility, reducing its balance to $3,088 million and issued US$600 million of 2.05% notes due July 2025 and US$500 million of 2.95% notes due July 2030. In the third quarter, the Company repaid $1,000 million of 2.89% medium-term notes and repaid $900 million of 2.05% medium term notes. In the fourth quarter, the Company issued $500 million of 1.45% medium-term notes due November 2023 and $300 million of 2.50% medium-term notes due January 2028.

The Kirby North facility, which was completed and commissioned in 2019, reached its targeted production capacity of 40,000 bbl/d in June 2020.

The North West Redwater Refinery, in which the Company has a 50% working interest, successfully reached commercial operations on June 1, 2020.

On October 6, 2020, the Company completed the acquisition of all of the issued and outstanding shares of Painted Pony Energy Ltd. ("Painted Pony") for a total purchase price of $111 million as well as assuming Painted Pony's total debt of approximately $397 million. Painted Pony was amalgamated with the Company on January 1, 2021.

2021

The initial rollout of the COVID-19 vaccine, which commenced internationally in December 2020, together with the continuation of agreements by OPEC+ to maintain the majority of production cuts continued to have an overall positive impact in 2021 on global demand and benchmark pricing for crude oil and the Company's products.

In January 2021, the presidential permit granted in 2019 on the Keystone XL Pipeline was revoked following the inauguration of the newly elected US President. The Company accrued a charge relating to the Keystone XL pipeline project of $143 million in the fourth quarter of 2020.

In 2021, the Company made a number of adjustments to its debt financing plan. This included the repayment and cancellation of the remaining balance on the $3,088 million Devon Credit Facility originally due in June 2022. In the third quarter, the Company repaid the US$500 million 3.45% notes originally due November 15, 2021. The Company also repaid $1,500 million on its $2,650 million term credit facility originally due February 2023, which reduced the facility balance to $1,150 million as at November 3, 2021. In the fourth quarter, the Company repaid the outstanding notional balance under its $1,000 million credit facility, which credit facility was not cancelled upon repayment and remains available to be drawn until March 31, 2022. In the fourth quarter, the Company also extended both of its $2,425 million revolving syndicated credit facilities originally due June 2022 and June 2023, to June 2024 and June 2025 respectively and increased each facility by $70 million to $2,495 million. In accordance with the terms of the extensions, and by mutual agreement, $70 million on each of the original revolving credit facilities was not extended and will expire on the original maturity dates of June 2022 and June 2023, respectively. Additionally, 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, which expire in August 2023, replacing the Company's previous base shelf prospectuses which expired in August 2021.

On June 9, 2021, the Company, together with Cenovus Energy, Imperial Oil, MEG Energy and Suncor Energy, announced the *Oil Sands Pathways to Net Zero* initiative, a unique alliance working collectively with the federal and Alberta governments to achieve net zero GHG emissions from oil sands operations by 2050. This groundbreaking industry and government collaboration is intended to support achievement of Canada's climate goals through the parallel development and deployment of next generation emissions reduction technology, infrastructure and operations projects designed to improve efficiency and reduce GHG emissions while balancing sustainable economic development and positioning Canadian oil and gas production to be the ESG-leading barrel to meet global energy demand.

During 2021, the Company completed the acquisition of all the issued and outstanding common shares of Storm Resources Limited ("Storm") for total cash consideration of approximately $771 million. At closing, the acquisition also included the assumption of long-term debt of approximately $183 million. Storm and CNR Montney Ltd. were amalgamated with the Company on January 1, 2022. Storm was involved in the exploration and development of natural gas and NGLs in the Montney region of British Columbia.

During 2021, the Company also completed a number of other opportunistic acquisitions. Two acquisitions consisted of natural gas assets located in the Montney region of British Columbia, with aggregate production of approximately 11,100 BOE/d. A third acquisition consisted of a net carried interest on an existing oil sands lease held by the Company, from which all current Horizon production volumes are derived. Total cash consideration paid for these acquisitions was approximately $450 million.

2022

In August 2021, OPEC+ countries announced the intention to lift certain production cuts initiated in 2020 that were intended to stem the volatility in crude prices. Monthly increases in OPEC+ quotas have been 400 Mbbl/d from August 2021 through February 2022.

On March 3, 2022, the Company announced that it targets to publish its 2021 Stewardship Report to Stakeholders in the third quarter of 2022, which shall include third party independent "reasonable assurance" on scope 1 and scope 2 emissions (including methane emissions) and "limited assurance" on scope 3 emissions. Additionally, the Company will continue to outline its pathways to lower carbon emissions across its asset base and its journey to achieve its goal of net zero GHG emissions in the oil sands.

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 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, 2021, the Company had the following full time equivalent permanent employees:

North America, Exploration and Production	4,603
North America, Oil Sands Mining and Upgrading	4,807
North Sea and Offshore Africa	325
Total Company	9,735

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 2021 annual production. Natural gas, primarily produced in Alberta, British Columbia and Saskatchewan, accounted for 23% of 2021 annual production. Light and medium crude oil and NGLs represented 10% of 2021 annual 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 21% of 2021 annual production, primary heavy crude oil which accounted for 5% of 2021 annual production, and Pelican Lake heavy crude oil, which accounted for 5% of 2021 annual 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; CO_2 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 Trans Mountain Pipeline Expansion ("TMX") that will provide waterborne access to international markets. Construction of the TMX is approximately 45% complete. However, construction activities were subject to certain disruptions and temporary suspensions in 2020 and 2021 related to COVID-19 impacts, BC floods along the right of way and other matters. Trans Mountain Corporation has announced that the TMX now targets mechanical completion in the third quarter of 2023. The total cost of the TMX is now estimated at approximately $21.4 billion.

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 and strategies 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 the 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 maintain biodiversity for terrestrial and aquatic systems and high value ecosystems; 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.

In addition, in 2021, the Company announced its participation in the Oil Sands Pathways to Net Zero initiative, an alliance of oil sands producers, working collectively with federal and provincial governments, to achieve net zero GHG emissions from oil sands operations by 2050 to help Canada achieve its climate goals, including its Paris Agreement commitment.

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. 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. The Company targets publication of its 2021 Stewardship Report to Stakeholders in the third quarter of 2022. This report will include third party independent "reasonable assurance" on its 2021 scope 1 and scope 2 emissions, including methane emissions, and "limited assurance" on its scope 3 emissions. The Company, through industry associations, 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 continues to implement flaring, venting and solution gas conservation programs, which influence and direct its future plans for new projects and facilities. In 2021, the Company completed 250 solution gas conservation projects in its primary heavy crude oil operations, resulting in a reduction of approximately 1.4 million tonnes/year of CO_2e. Over the past five years, the Company has spent over $28.7 million in its primary heavy crude oil and in situ oil sands operations to conserve the equivalent of over 11.4 million tonnes of CO_2e. The Company also monitors compressor fleet performance as part of its compressor optimization initiative to improve fuel gas efficiency, and has ongoing methane reduction programs for pneumatic devices. Since 2018, the Company has completed over 6,400 pneumatic retrofits and removals resulting in a cumulative CO_2e reduction from its operations of approximately 640,000 tonnes/year, of which approximately 1,400 retrofits/removals equivalent to 140,000 tonnes/year CO_2e were completed in 2021. 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 of up to 400,000 tonnes/year for injection of CO_2 in oil sands tailings, and the recovery of hydrocarbon liquids from refinery fuel gas. Additionally, at the Company's non-operated Quest Carbon Capture and Storage Facility, approximately 1.1 million tonnes/year of CO_2 is captured and permanently sequestered in geological storage. Since 2015, approximately 6 million tonnes of CO_2 has been captured and safely stored at Quest.

The Company has water programs to improve the efficiency of use and recycle rates as well as reduce fresh water use, including new targets related to fresh river water use intensity in its oil sands mining operations and fresh water use intensity in its thermal in situ operations, both of which were announced in 2021. 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 that allows for the progressive reclamation of large contiguous areas of land to return sites to their former state and provides the foundation for the enhancement of biodiversity and functional wildlife habitats. The Company continued its environmental liability reduction program with the abandonment of 3,079 inactive wells, and has initiated reclamation at many of these sites with the eventual goal of reclamation certification. In 2021, the Company received 889 reclamation certificates representing 1,644 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 single turbine operations and enhancements in natural gas compression across the North Sea, improving GHG emissions intensity.

In 2021, the Murchison decommissioning activities were completed. The topside dismantling of the Ninian North platform commenced at an onshore facility in 2020 and the Ninian North jacket is targeted to be removed in 2022 and subsequently dismantled onshore with a recycling target of 98%. Decommissioning activities commenced at the Banff and Kyle fields in 2020 and are targeted to be substantially complete by 2024.

B. REGULATORY MATTERS

The Company's business is subject to regulations generally established through government legislation and governmental agencies. A summary of certain key regulatory regimes impacting the Company's operations 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 primary lease is issued for fifteen years. Continued primary oil sands leases that are designated as "producing" will continue for as long as the minimum level of production is maintained while those designated as "non-producing" and not meeting the required minimum level of production 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 July 13, 2016 and the MRF applying to wells drilled on or after January 1, 2017. Wells drilled between July 13, 2016 and December 31, 2016 could elect to opt-in to the MRF if certain criteria were met. 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 23.2% in 2021. The government of Alberta has enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, 10% effective January 1, 2020 and 8% effective July 1, 2020.

In 2021, the British Columbia government initiated a royalty review to assess its current oil and natural gas royalty system with the outcomes of the review to be released during 2022. The impact to industry of potential changes will be assessed once the government's review has been finalized.

- **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 Agreement, with a commitment to reduce GHG emissions by 40-45% from 2005 levels by 2030. The Canadian government has also committed to cap and cut emissions from the oil and gas sector, with further details to be developed in 2022. In addition, Canada has committed to reduce methane emissions from the upstream oil and natural gas sector by 40-45% by 2025, and by 75% by 2030, both as compared to 2012 levels. In December 2020, the federal government announced its intention to increase the carbon price to $170/tonne by 2030 in annual increments of $15/tonne after 2022. 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. Draft Clean Fuel regulations were released in December 2020 and only apply to producers or importers of liquid fuels (including gasoline, diesel, kerosene and light and heavy fuel oils). The final Clean Fuel Standard regulations are expected to be published in 2022.

- **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, 2020, Alberta replaced the GHG regulation (the Carbon Competitiveness Incentive Regulation) 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 for emissions above the TIER regulated limits was $40/tonne in 2021 and is $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 and North West Redwater bitumen upgrader and refinery are also subject to compliance under the regulations.

In British Columbia, carbon tax is currently being assessed at $45/tonne of CO_2e on fuel consumed and gas flared and vented in the province. In February 2021, the British Columbia government announced that the carbon tax rate would increase to $50/tonne effective April 1, 2022. The British Columbia government has implemented 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 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 2020. 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 50 kilotonnes CO_2e annually. Facilities with emissions equal to or greater than 10 kilotonnes CO_2e annually can voluntarily opt-in to the system.

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

By 2025, the federal government has committed to reduce methane emissions from the oil and gas sector by 40% to 45% below 2012 levels. 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 provinces of British Columbia, Alberta and Saskatchewan have implemented provincial methane regulations, and have reached equivalency agreements with the federal government. Accordingly, the applicable provincial methane regulations govern in the three western provinces whereas the federal methane regulation applies to methane emissions in the province of Manitoba.

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, a new UK Emissions Trading Scheme ("ETS") was launched on January 1, 2021. The new scheme is aligned with the EU ETS rules and applies to energy intensive industries, the power generation sector and aviation. The Company continues to focus on implementing CO_2 emissions reduction opportunities at its 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.

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.

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 develop mitigation plans for 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+, the economic condition of Canada, the US, the European Union and Asia, government regulation, political stability in the Middle East and elsewhere, geopolitical conflicts, 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 31% of the Company's 2021 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.

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, mines, 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 regulatory 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. Environmental monitoring in the oil sands is performed in collaboration with the federal and provincial governments, Indigenous communities and industry, in order to enhance the understanding of the cumulative effects of oil sands development. 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, associated compliance costs and reduction targets, access to markets and capital, societal preferences and reputational risk, and technology development, as described in more detail below.

- **Future Regulatory Changes / Compliance Costs / Reduction Targets**

  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 tracks the development of policies and regulations at the international, national, federal and provincial level. In December 2020, the federal government announced its intention to surpass Canada's previously stated reduction target under the Paris Agreement, to increase the carbon price to $170 in 2030, and to establish methane reduction targets for 2030 and 2035. In addition, draft regulations under the Clean Fuel Standard were released in 2020 and are planned to take effect in December 2022. Aspects of the Clean Fuel Standard will increase the cost of liquid fuels consumed in the Company's operations while also providing a potential mechanism to generate offset credits.

In addition to the announced Pathways initiative, the Company continues to pursue other GHG emissions reduction initiatives including: solution gas conservation, compressor optimization to improve fuel gas efficiency, reductions in pneumatic devices, CO_2 capture and injection in oil sands tailings, CO_2 capture and storage in association with EOR, CO_2 capture and storage at Quest, and technology development through 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.

The Company's ability to achieve government, Pathways and other corporate emissions or environmental reduction targets could require the development of new technology, the success of which is unknown, as well as significant capital and resources, with the potential that the costs required to achieve targets and goals are materially different from original estimates and expectations. While the intent is to improve efficiency and increase the offering of low carbon energy, the shift in resources and focus to emissions reductions could negatively impact operating results.

- **Societal Preferences / Reputational Risk**

  Changes in public support for climate action, particularly for oil sands, combined with increased activism and opposition to fossil fuels, which are designed to change consumption habits in order to accelerate the reduction of the global consumption of carbon-based energy, may impact the market for the Company’s products and securities and impact its ability to obtain approvals for new projects. The timing and pace of change to a low carbon economy is uncertain and the ability to access insurance and capital may be adversely affected in the event that financial institutions, investors, insurers, rating agencies and/or lenders adopt more restrictive de-carbonization policies. In addition, behavioural changes by the public, such as a shift in transportation preferences or the use of alternative energy sources, may impact the demand for crude oil and the Company's products.

- **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, emergence and use of renewable energy sources could affect the demand for the Company’s products thereby affecting its competitiveness and profitability. The development and commercialization (including the availability, cost and effectiveness) of new technologies necessary to achieve emissions reductions and environmental improvements is uncertain.

- **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 have the potential to impact the certainty and timelines for the regulatory process on large energy projects, including increased requirements for Indigenous consultation. Some examples include the federal Canadian Net-Zero Emissions Accountability Act, federal legislation implementing the United Nations Declaration on the Rights of Indigenous Peoples Act, and the federal Impact Assessment Act, the British Columbia Declaration on the Rights of Indigenous Peoples Act (DRIPA), and the British Columbia policy response to recent Indigenous litigation (e.g. *Yahey vs. British Columbia* 2021 (B.C.S.C. 1287), a case regarding the cumulative effects of development on Treaty 8 rights).

- **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, including as a result of the delay, revocation, or conditions imposed on, regulatory approvals for pipeline projects such as the Trans Mountain Pipeline Expansion. This risk was demonstrated in the cancellation of the Presidential Permit for TC Energy's Keystone XL Pipeline Expansion, which was revoked in January of 2021. These risks could result in a competitive disadvantage if producers in other jurisdictions are not subject to similar regulatory burdens.

- **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 ("Directive 85"), which was updated in October 2017. Directive 85 establishes performance criteria for tailings operations and sets out the requirements for approval, monitoring and reporting in respect of tailings ponds and tailings management plans.

  The Company continues to implement and adhere to the conditions stipulated in the approved Tailings Management Plans for the Horizon Mine, and the AOSP's Muskeg River and Jackpine Mines and thereby meet the requirements of the government of Alberta's Tailings Management Framework (2015) and Directive 85. However, 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"). The Company obtained regulatory approval from the AER to integrate these assets into one mining project in January 2021. This approval allows the amalgamation of the Horizon South minable area into the existing Horizon mine pit development. The integrated approval avoids the need for a second external tailings facility (i.e. tailings pond) for Horizon South, as well as allows for progressive mining and backfilling of the extended pit with treated tailings, which avoids a future end pit lake that would have been required if Horizon South was mined separately.

  In December 2018, Alberta Environment and Parks released the new Dam and Canal Safety Directive (the " Dam Safety Directive"). The Dam Safety 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. In January 2020, the AER issued Manual 19 (Decommissioning, Closure, and Abandonment of Dams at Energy Projects) as a supplement to the Dam Safety Directive, which is intended to provide additional guidance on the AER's application of the Dam Safety Directive. Muskeg River Mine continues to advance the decommissioning process for its external tailings facility and is waiting for the final construction completion report to be authorized before finalizing the regulatory requirements with the AER for its deregistration as a dam structure, further 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 the operation of facilities. Draft frameworks on biodiversity may establish further limits on development that may limit operations and expansion of facilities. Regional access management plans may pose limitations on resource development through limits on infrastructure.

  Water licencing, use and release standards are becoming increasingly stringent both in the process of obtaining access to water and to manage it efficiently. 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. For example, in the case of Woodland Caribou, the requirements related to undisturbed habitat in addition to minimum herd population may impact plans for crude oil and natural gas expansion. Both the oil and gas and forestry industries are undertaking mitigation measures to return habitat function by restricting predator access on seismic lines, restoring forests through accelerated reclamation and completing project development planning to minimize caribou disturbance. In addition, mitigation activities such as maternity pens to raise young caribou are being supported by the Company to improve herd populations. 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.

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 with potential impacts to supply chain and customer/vendor operations or critical infrastructure owned and operated by the Company or third parties. 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 operations. In addition, labour risk associated with work interruptions and the ability to secure necessary manpower may impact the timely and cost effective manner in which projects are completed.

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, higher costs as a result of 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.

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 crimes 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 assets and 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 interference with operation of, or damage to, Company property (such as was experienced by the Colonial Pipeline in 2021) or the loss, disclosure or theft of confidential information related to the Company's proprietary business activities, the personnel files of its employees and personal information of landowners, vendors, customers and other third parties doing business with the Company. Although the Company has implemented cybersecurity protocols and procedures to address this risk, such protocols and procedures may be insufficient to prevent or mitigate information security risks.

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. Although 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, such programs may be insufficient to prevent or mitigate such threats.

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.

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.

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 COVID-19 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 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. During the COVID-19 pandemic, the Company's operations were designated as "essential services" by applicable government authorities, which permitted operations to continue in areas that may have otherwise been impacted by government imposed lockdown measures. Depending on the severity, the potential resurgence of the virus, the timing and availability of vaccines and the speed of vaccine distribution, 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 effect 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, 2021, the Company retained Independent Qualified Reserves Evaluators (“IQRE”), Sproule Associates Limited and Sproule International Limited (together as “Sproule”) and GLJ Ltd. (“GLJ”), to evaluate and review all of the Company’s proved and proved plus probable reserves with an effective date of December 31, 2021 and a preparation date of February 7, 2022. 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 2021 Annual Report, 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 "Special Note Regarding Forward-Looking Statements"and "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, 2021
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	83	83	215	587	6,960	4,471	130	8,803
Developed Non-Producing	11	11	—	32	—	258	5	102
Undeveloped	51	74	56	2,012	37	7,401	283	3,747
Total Proved	145	169	270	2,631	6,998	12,129	418	12,652
Probable	57	80	118	1,706	537	8,056	224	4,066
Total Proved plus Probable	202	249	388	4,337	7,535	20,185	643	16,717
North Sea								
Proved								
Developed Producing	17					3		18
Developed Non-Producing	30					1		30
Undeveloped	31					4		32
Total Proved	79					8		80
Probable	38					3		39
Total Proved plus Probable	117					11		119
Offshore Africa								
Proved								
Developed Producing	34					20		38
Developed Non-Producing	9					3		10
Undeveloped	32					9		34
Total Proved	76					32		81
Probable	29					21		32
Total Proved plus Probable	105					53		114
Total Company								
Proved								
Developed Producing	135	83	215	587	6,960	4,494	130	8,859
Developed Non-Producing	50	11	—	32	—	262	5	142
Undeveloped	115	74	56	2,012	37	7,413	283	3,812
Total Proved	300	169	270	2,631	6,998	12,168	418	12,813
Probable	125	80	118	1,706	537	8,080	224	4,137
Total Proved plus Probable	424	249	388	4,337	7,535	20,249	643	16,950

Summary of Company Net Reserves

As of December 31, 2021
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	74	70	167	463	5,827	4,111	106	7,393
Developed Non-Producing	9	9	—	25	—	234	4	87
Undeveloped	43	63	46	1,577	15	6,731	240	3,106
Total Proved	126	142	213	2,065	5,843	11,076	350	10,586
Probable	48	66	85	1,332	431	7,239	182	3,349
Total Proved plus Probable	174	208	298	3,397	6,273	18,315	532	13,935
North Sea								
Proved								
Developed Producing	17					3		18
Developed Non-Producing	30					1		30
Undeveloped	31					4		32
Total Proved	79					8		80
Probable	38					3		39
Total Proved plus Probable	117					11		119
Offshore Africa								
Proved								
Developed Producing	31					18		34
Developed Non-Producing	8					2		8
Undeveloped	26					5		26
Total Proved	64					25		68
Probable	22					14		24
Total Proved plus Probable	85					39		92
Total Company								
Proved								
Developed Producing	122	70	167	463	5,827	4,132	106	7,445
Developed Non-Producing	47	9	—	25	—	237	4	125
Undeveloped	100	63	46	1,577	15	6,740	240	3,164
Total Proved	269	142	213	2,065	5,843	11,109	350	10,734
Probable	108	66	85	1,332	431	7,256	182	3,412
Total Proved plus Probable	376	208	298	3,397	6,273	18,364	532	14,146

Reconciliation of Company Gross Reserves

As of December 31, 2021
Forecast Prices and Costs

TOTAL 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, 2020	138	177	265	2,483	6,962	9,413	326	11,920
Discoveries	—	—	—	—	—	—	—	—
Extensions	1	7	—	119	—	598	15	243
Infill Drilling	3	4	—	—	—	170	13	47
Improved Recovery	—	—	1	19	—	3	—	21
Acquisitions	—	—	—	—	—	1,715	59	345
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	14	13	22	—	—	310	10	111
Technical Revisions	5	(9)	2	105	199	534	13	404
Production	(16)	(23)	(20)	(95)	(164)	(613)	(18)	(438)
December 31, 2021	**145**	**169**	**270**	**2,631**	**6,998**	**12,129**	**418**	**12,652**
North Sea								
December 31, 2020	96					12		98
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	(11)					(3)		(11)
Production	(6)					(1)		(7)
December 31, 2021	**79**					**8**		**80**
Offshore Africa								
December 31, 2020	81					40		87
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	1					(3)		—
Production	(5)					(4)		(6)
December 31, 2021	**76**					**32**		**81**
Total Company								
December 31, 2020	315	177	265	2,483	6,962	9,465	326	12,106
Discoveries	—	—	—	—	—	—	—	—
Extensions	1	7	—	119	—	598	15	243
Infill Drilling	3	4	—	—	—	170	13	47
Improved Recovery	—	—	1	19	—	3	—	21
Acquisitions	—	—	—	—	—	1,715	59	345
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	14	13	22	—	—	309	10	110
Technical Revisions	(5)	(9)	2	105	199	528	13	392
Production	(28)	(23)	(20)	(95)	(164)	(619)	(18)	(451)
December 31, 2021	**300**	**169**	**270**	**2,631**	**6,998**	**12,168**	**418**	**12,813**

TOTAL 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, 2020	53	82	130	1,674	534	6,428	174	3,719
Discoveries	—	—	—	—	—	—	—	—
Extensions	—	3	—	39	—	406	15	125
Infill Drilling	2	2	—	—	—	517	9	98
Improved Recovery	—	—	1	5	—	1	—	5
Acquisitions	—	—	—	—	—	1,264	41	251
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	3	6	(16)	2	—	58	1	6
Technical Revisions	(1)	(12)	3	(14)	3	(618)	(15)	(140)
Production	—	—	—	—	—	—	—	—
December 31, 2021	**57**	**80**	**118**	**1,706**	**537**	**8,056**	**224**	**4,066**
North Sea								
December 31, 2020	64					5		65
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	1					—		1
Technical Revisions	(27)					(2)		(27)
Production	—					—		—
December 31, 2021	**38**					**3**		**39**
Offshore Africa								
December 31, 2020	31					24		35
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	(1)					—		(1)
Technical Revisions	(1)					(3)		(2)
Production	—					—		—
December 31, 2021	**29**					**21**		**32**
Total Company								
December 31, 2020	148	82	130	1,674	534	6,457	174	3,819
Discoveries	—	—	—	—	—	—	—	—
Extensions	—	3	—	39	—	406	15	125
Infill Drilling	2	2	—	—	—	517	9	98
Improved Recovery	—	—	1	5	—	1	—	5
Acquisitions	—	—	—	—	—	1,264	41	251
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	3	6	(16)	2	—	58	1	6
Technical Revisions	(29)	(12)	3	(14)	3	(622)	(15)	(168)
Production	—	—	—	—	—	—	—	—
December 31, 2021	**125**	**80**	**118**	**1,706**	**537**	**8,080**	**224**	**4,137**

TOTAL 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, 2020	191	260	395	4,157	7,496	15,841	500	15,639
Discoveries	—	—	—	—	—	—	—	—
Extensions	2	10	—	158	—	1,004	30	368
Infill Drilling	4	6	—	—	—	687	21	146
Improved Recovery	—	—	2	23	—	4	—	26
Acquisitions	—	—	—	—	—	2,979	100	596
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	18	18	7	2	—	368	11	116
Technical Revisions	4	(22)	5	91	202	(83)	(1)	264
Production	(16)	(23)	(20)	(95)	(164)	(613)	(18)	(438)
December 31, 2021	**202**	**249**	**388**	**4,337**	**7,535**	**20,185**	**643**	**16,717**
North Sea								
December 31, 2020	160					17		163
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	1					—		1
Technical Revisions	(37)					(5)		(38)
Production	(6)					(1)		(7)
December 31, 2021	**117**					**11**		**119**
Offshore Africa								
December 31, 2020	112					64		122
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	(1)					(1)		(1)
Technical Revisions	(1)					(6)		(2)
Production	(5)					(4)		(6)
December 31, 2021	**105**					**53**		**114**
Total Company								
December 31, 2020	463	260	395	4,157	7,496	15,922	500	15,925
Discoveries	—	—	—	—	—	—	—	—
Extensions	2	10	—	158	—	1,004	30	368
Infill Drilling	4	6	—	—	—	687	21	146
Improved Recovery	—	—	2	23	—	4	—	26
Acquisitions	—	—	—	—	—	2,979	100	596
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	18	18	7	2	—	368	11	116
Technical Revisions	(34)	(22)	5	91	202	(94)	(1)	224
Production	(28)	(23)	(20)	(95)	(164)	(619)	(18)	(451)
December 31, 2021	**424**	**249**	**388**	**4,337**	**7,535**	**20,249**	**643**	**16,950**

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.
   - "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. 2021 reserves reconciliation highlights:

Total Proved Crude Oil, Bitumen (Thermal Oil) and NGLs reserves increased by 257 MMbbl:

- Extensions: Increase of 143 MMbbl primarily due to 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 19 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 20 MMbbl primarily due to increased recovery of Bitumen (Thermal Oil) at Jackfish and Kirby properties.
- Acquisitions: Increase of 59 MMbbl primarily due to natural gas (NGLs) acquisitions in northeast British Columbia.
- Economic Factors: Increase of 59 MMbbl primarily due to higher product pricing.
- Technical Revisions: Increase of 304 MMbbl primarily due to transfers at Oil Sands Mining and Upgrading (SCO), Bitumen (Thermal Oil) improved performance at Kirby and Jackfish, as well as improved performance at various natural gas (NGLs) properties, offset by removal of future undeveloped reserves at North Sea and Primary Heavy Crude Oil properties.
- Production: Decrease of 348 MMbbl.

Total Proved Natural Gas reserves increased by 2,704 Bcf:

- Extensions: Increase of 598 Bcf primarily due to extension drilling/future offset additions in the Montney and other unconventional formations of northwest Alberta and northeast British Columbia.
- Infill Drilling: Increase of 170 Bcf primarily due to infill drilling/future offset additions in the Montney and other unconventional formations of northwest Alberta and northeast British Columbia.
- Acquisitions: Increase of 1,715 Bcf primarily due to the Storm Resources Ltd. and other acquisitions in northeast British Columbia.
- Dispositions: Decrease of 1 Bcf from Natural Gas properties in North America.
- Economic Factors: Increase of 309 Bcf due to higher product pricing.
- Technical Revisions: Increase of 528 Bcf primarily due to overall positive revisions in several North America core areas as a result of increased recovery and category transfers from probable to proved.
- Production: Decrease of 619 Bcf.

Total Proved plus Probable Crude Oil, Bitumen and NGLs reserves increased by 304 MMbbl:

- Extensions: Increase of 201 MMbbl primarily due to 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 31 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 25 MMbbl primarily due to increased recovery of Bitumen (Thermal Oil) at Jackfish and Kirby properties.
- Acquisitions: Increase of 100 MMbbl primarily due to natural gas (NGLs) acquisitions in northeast British Columbia.
- Economic Factors: Increase of 55 MMbbl primarily due to higher product pricing.
- Technical Revisions: Increase of 240 MMbbl primarily due to transfers at Oil Sands Mining and Upgrading (SCO), Bitumen (Thermal Oil) improved performance at Kirby and Jackfish, as well as improved performance at Pelican Lake (Pelican Lake Heavy Crude Oil), offset by removal of future undeveloped reserves at North Sea and Primary Heavy Crude Oil properties.
- Production: Decrease of 348 MMbbl.

Total Proved plus Probable Natural Gas reserves increased by 4,327 Bcf:

- Extensions: Increase of 1,004 Bcf primarily due to extension drilling/future offset additions in the Montney and other unconventional formations of northwest Alberta and northeast British Columbia.
- Infill Drilling: Increase of 687 Bcf primarily due to infill drilling/future offset additions in the Montney and other unconventional formations of northwest Alberta and northeast British Columbia.
- Acquisitions: Increase of 2,979 Bcf primarily due to the Storm Resources Ltd. and other acquisitions in northeast British Columbia.
- Dispositions: Decrease of 1 Bcf from Natural Gas properties in North America.
- Economic Factors: Increase of 368 Bcf due to higher product pricing.
- Technical Revisions: Decrease of 94 Bcf primarily due to future extension and infill undeveloped reserves in North America properties because of revised Company development plans.
- Production: Decrease of 619 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, 2021 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, 2021 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, 2021
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	391,270	149,794	86,420	61,772	49,124	11.69
Developed Non-Producing	2,730	1,199	847	683	578	9.77
Undeveloped	96,525	52,810	29,565	18,008	11,752	9.52
Total Proved	490,524	203,803	116,832	80,463	61,454	11.04
Probable	142,971	47,741	22,861	13,734	9,468	6.83
Total Proved plus Probable	633,495	251,544	139,693	94,197	70,921	10.02
North Sea						
Proved						
Developed Producing	(1,260)	(571)	(234)	(63)	26	(13.04)
Developed Non-Producing	843	704	602	524	464	19.82
Undeveloped	2,302	1,744	1,362	1,091	892	42.65
Total Proved	1,885	1,877	1,731	1,553	1,382	21.57
Probable	3,378	2,491	1,907	1,507	1,225	49.26
Total Proved plus Probable	5,263	4,368	3,637	3,060	2,607	30.58
Offshore Africa						
Proved						
Developed Producing	613	695	666	606	542	19.71
Developed Non-Producing	440	319	242	189	153	30.61
Undeveloped	1,703	1,149	810	591	442	30.65
Total Proved	2,755	2,163	1,718	1,386	1,137	25.22
Probable	1,865	1,231	859	629	478	36.14
Total Proved plus Probable	4,621	3,394	2,577	2,015	1,615	28.05
Total Company						
Proved						
Developed Producing	390,623	149,918	86,852	62,315	49,692	11.67
Developed Non-Producing	4,012	2,222	1,690	1,397	1,195	13.53
Undeveloped	100,529	55,703	31,738	19,690	13,086	10.03
Total Proved	495,165	207,843	120,280	83,402	63,973	11.21
Probable	148,214	51,463	25,628	15,870	11,170	7.51
Total Proved plus Probable	643,379	259,306	145,908	99,272	75,143	10.31

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

As of December 31, 2021
Forecast Prices and Costs

($ millions)	Discount @ 0%	Discount @ 5%	Discount @ 10%	Discount @ 15%	Discount @ 20%
North America					
Proved					
Developed Producing	301,465	116,250	67,574	48,591	38,815
Developed Non-Producing	2,361	932	637	510	430
Undeveloped	74,206	39,866	21,933	13,089	8,337
Total Proved	378,032	157,048	90,144	62,190	47,582
Probable	109,100	36,188	17,205	10,271	7,046
Total Proved plus Probable	487,133	193,235	107,349	72,460	54,627
North Sea					
Proved					
Developed Producing	(493)	(211)	(71)	2	40
Developed Non-Producing	346	348	328	303	277
Undeveloped	1,314	1,030	824	671	556
Total Proved	1,167	1,167	1,082	976	873
Probable	2,026	1,511	1,169	932	763
Total Proved plus Probable	3,192	2,678	2,250	1,908	1,636
Offshore Africa					
Proved					
Developed Producing	412	529	525	484	435
Developed Non-Producing	333	240	181	141	113
Undeveloped	1,301	880	621	453	339
Total Proved	2,046	1,649	1,328	1,079	888
Probable	1,399	923	644	471	358
Total Proved plus Probable	3,445	2,573	1,972	1,550	1,245
Total Company					
Proved					
Developed Producing	301,384	116,568	68,029	49,077	39,289
Developed Non-Producing	3,041	1,521	1,147	954	820
Undeveloped	76,820	41,775	23,378	14,214	9,233
Total Proved	381,245	159,864	92,554	64,244	49,342
Probable	112,525	38,622	19,018	11,674	8,167
Total Proved plus Probable	493,769	198,486	111,572	75,918	57,509

Total Future Net Revenue (Undiscounted)

As of December 31, 2021
Forecast Prices and Costs

	North America		North Sea		Offshore Africa		Total Company	
($ millions)	Total Proved	Total Proved plus Probable	Total Proved	Total Proved plus Probable	Total Proved	Total Proved plus Probable	Total Proved	Total Proved plus Probable
Revenue	1,156,918	1,461,535	8,413	12,312	6,342	8,555	1,171,673	1,482,401
Royalties	196,369	255,514	19	29	215	303	196,603	255,845
Production Costs	362,996	442,703	4,294	4,672	2,037	2,172	369,327	449,548
Development Costs	87,824	109,368	653	786	851	960	89,328	111,114
ADR Costs for Future Development	694	1,210	—	—	29	44	723	1,253
Future Net Revenue Before Income Taxes **Excluding ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)**	509,034	652,740	3,447	6,826	3,210	5,076	515,691	664,641
ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	18,509	19,245	1,562	1,562	455	455	20,527	21,263
Future Net Revenue Before Income Taxes **Including ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)**	490,524	633,495	1,885	5,263	2,755	4,621	495,165	643,379
Income Taxes	112,492	146,362	718	2,071	710	1,176	113,920	149,609
Future Net Revenue After Income Taxes	**378,032**	**487,133**	**1,167**	**3,192**	**2,046**	**3,445**	**381,245**	**493,769**

Future Net Revenue By Product Type

As of December 31, 2021
Forecast Prices and Costs

Total Proved

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)	7,766	19.80
Primary Heavy Crude Oil (including solution gas)	2,531	17.41
Pelican Lake Heavy Crude Oil (including solution gas)	3,660	17.15
Bitumen (Thermal Oil)	28,477	13.79
Synthetic Crude Oil	68,962	11.80
Natural Gas (including by-products but excluding solution gas and by-products from crude oil wells)	12,274	5.91
Total **Excluding ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)**	123,669	11.52
ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	(3,389)	
Total Including ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	**120,280**	**11.21**

Total Proved plus Probable

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)	11,946	21.79
Primary Heavy Crude Oil (including solution gas)	3,750	17.68
Pelican Lake Heavy Crude Oil (including solution gas)	4,766	15.98
Bitumen (Thermal Oil)	35,694	10.51
Synthetic Crude Oil	74,555	11.88
Natural Gas (including by-products but excluding solution gas and by-products from crude oil wells)	18,632	5.45
Total **Excluding ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)**	149,343	10.56
ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	(3,435)	
Total Including ADR Costs for Existing Development (Equivalent to the Financial Statement ARO)	**145,908**	**10.31**

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, 2021 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 the proposed federal Greenhouse Gas Pollution Pricing Act, which reaches $170/tonne in 2030. For reserves in the North Sea, future net revenue includes carbon costs associated with the UK Emissions Trading Scheme.
3. Unit values ($/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 for the year ended December 31, 2021 and the annual MD&A for the year ended December 31, 2021, dated March 2, 2022.
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 3-consultant-average of price forecasts developed by Sproule, GLJ and McDaniel & Associates Consultants Ltd. ("McDaniel"), dated December 31, 2021. The following is a summary of the 3-consultant-average price forecast. All prices increase at a rate of 2% per year after 2026.

		2022	2023	2024	2025	2026
Crude Oil and NGLs						
WTI	US$/bbl	72.83	68.78	66.76	68.09	69.45
WCS	C$/bbl	74.42	69.17	66.54	67.87	69.23
Canadian Light Sweet	C$/bbl	86.82	80.73	78.01	79.57	81.16
Cromer LSB	C$/bbl	87.30	82.30	79.69	81.29	82.92
Edmonton C5+	C$/bbl	91.85	85.53	82.98	84.63	86.33
Brent	US$/bbl	75.33	71.46	69.62	71.01	72.44
Natural Gas						
AECO	C$/MMBtu	3.56	3.21	3.05	3.11	3.17
BC Westcoast Station 2	C$/MMBtu	3.48	3.14	2.98	3.03	3.10
Henry Hub	US$/MMBtu	3.85	3.44	3.17	3.24	3.30

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 º 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 º 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.

- "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. Effective April 1, 2021, the COGE Handbook includes price forecast guidelines for the preparation of commodity price forecasts for use in reserve evaluations. For year-end 2021, the methodology used by Sproule, GLJ and McDaniel for determining their price forecasts is consistent with the COGE Handbook guidelines.
3. 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.
4. The Company's 2021 average pricing, net of blending costs and excluding risk management activities, was $80.82/bbl for light and medium crude oil, $65.88/bbl for primary heavy crude oil, $68.05/bbl for Pelican Lake heavy crude oil, $60.20/bbl for bitumen (thermal oil), $77.95/bbl for SCO, $47.59/bbl for NGLs, and $4.07/Mcf for natural gas.
5. Production and capital costs are escalated at the 3-consultant-average cost inflation rate of 0% per year for 2022, 2.33% per year for 2023 and 2% per year after 2023 for all products.
6. The 3-consultant-average foreign exchange rate of 0.7967 US$/C$ for 2022 and 0.7967 US$/C$ after 2022 was used in the 2021 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

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)
2019								
First Attributed	7	21	—	538	133	297	17	765
Total	163	85	58	1,771	133	3,101	177	2,903
2020								
First Attributed	4	1	—	17	8	2,561	48	506
Total	149	84	49	1,876	92	5,476	225	3,388
2021								
First Attributed	2	5	—	119	—	2,068	69	541
Total	115	74	56	2,012	37	7,413	283	3,812

Probable Undeveloped

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)
2019								
First Attributed	3	25	—	166	—	330	14	262
Total	79	63	28	1,406	157	2,127	103	2,191
2020								
First Attributed	2	2	—	4	—	3,285	41	597
Total	74	60	36	1,427	153	5,244	141	2,764
2021								
First Attributed	2	3	—	39	—	2,037	60	443
Total	58	57	27	1,467	106	6,711	183	3,017

The assignment of some proved undeveloped and probable undeveloped reserves beyond 2 years 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. The IQRE reserves evaluation report documents the evaluation, assignment and justification for undeveloped reserves beyond the NI 51-101 development timing guidelines. The Company's justifications for reserves development timing beyond 2 years are summarized by product type below:

1. Light and Medium Crude Oil and Primary Heavy Crude Oil undeveloped reserves are located throughout the Company's core areas in western Canada, the North Sea and Offshore Africa. Development timing is justified to accommodate the following:
   - capital projects with facility constraints and development plans designed to optimize the operation and deliver production for the life of the facilities;
   - resource plays with extensive ongoing development;
   - EOR or waterflood projects with ongoing, extensive development opportunity;
   - strict ESG or regulatory development restrictions limit the development drilling that would otherwise proceed at a quicker pace; and
   - offshore projects with long lead times and facility constraints.
2. Pelican Lake Heavy Crude Oil is produced at a large heavy crude oil polymer EOR flood project with chemical and facility constraints. The development plan is designed to optimize the purchase and use of chemicals and deliver production for the life of the facilities.
3. Bitumen (Thermal Oil) development plans are designed to optimize the operation and deliver production for the life of the facilities over the next fifty years.
4. Synthetic Crude Oil reserves are associated with two large oil sands mining and upgrading projects with long lead times and facility constraints. The development plans are designed to optimize the operation and deliver production for the life of the facilities.
5. Natural Gas undeveloped reserves are located throughout the Company's core areas in western Canada. Development timing is justified to accommodate the following:
   - capital projects with facility constraints and development plans designed to optimize the operation and deliver production for the life of the facilities;
   - resource plays with extensive ongoing development; and
   - strict ESG or regulatory development restrictions limit the development drilling that would otherwise proceed at a quicker pace.

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, 2021. 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, 2021 and forecast estimates of ADR costs attributable to future development activity.

Future Development Costs (Undiscounted)

($ millions)	2022	2023	2024	2025	2026	Thereafter	Total	Total Discounted at 10%
Total Proved								
North America	2,922	4,048	3,934	3,406	3,149	70,364	87,824	30,013
North Sea	100	171	140	93	43	105	653	497
Offshore Africa	129	256	179	37	31	219	851	629
Total Company	3,152	4,476	4,253	3,536	3,224	70,688	89,328	31,140
Total Proved plus Probable								
North America	3,050	4,276	4,218	3,745	3,643	90,435	109,368	35,289
North Sea	102	199	156	133	57	139	786	589
Offshore Africa	133	280	252	37	31	228	960	714
Total Company	3,286	4,755	4,625	3,915	3,731	90,802	111,114	36,592

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, 2021 and 2020.

	2021 Average Daily Production Rates		2020 Average Daily Production Rates	
Region	**Crude Oil & NGLs (bbl)**	**Natural Gas (MMcf)**	Crude Oil & NGLs (bbl)	Natural Gas (MMcf)
North America				
Northeast British Columbia	17,456	640	12,545	420
Northwest Alberta	49,900	656	44,129	639
Northern Plains	386,460	156	383,676	149
Southern Plains	14,179	225	14,489	239
Southeast Saskatchewan	4,626	3	5,604	3
Oil Sands Mining & Upgrading	448,133	—	417,351	—
North America Total	920,754	1,680	877,794	1,450
International				
North Sea UK Sector	17,633	3	23,142	12
Offshore Africa	14,017	12	17,022	15
International Total	31,650	15	40,164	27
Company Total	952,404	1,695	917,958	1,477

Northeast British Columbia

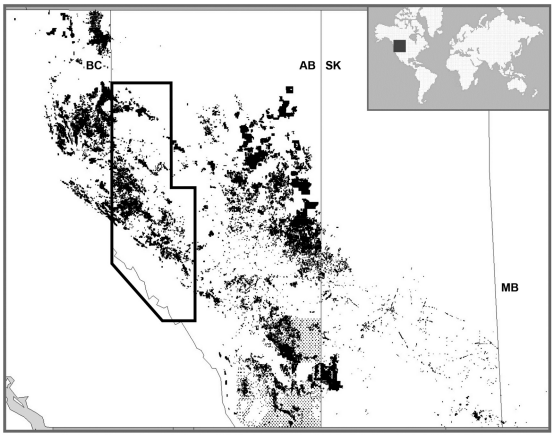
The northeast British Columbia region holds a significant portion of the Montney formation and provides exploration and development opportunities in combination with significant controlled infrastructure. The exploration strategy focuses on comprehensive evaluation through two dimensional seismic, three dimensional seismic and targeting economic prospects close to existing infrastructure.

In 2021, the Company completed three Montney natural gas acquisitions, including the corporate acquisition of Storm Resources Ltd. on December 17, 2021, which included owned and dedicated third party natural gas processing capacity.

This region also includes the Septimus and Townsend Montney natural gas assets with owned natural gas processing capacity as well as dedicated third party natural gas processing capacity.

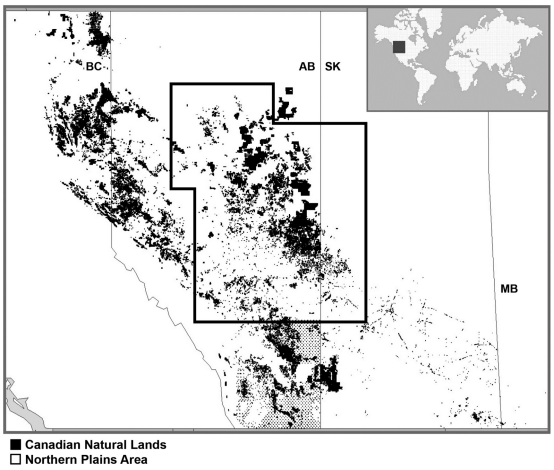
The southern portion of this region encompasses the Company’s BC Foothills assets where natural gas is produced from the deep Mississippian and Triassic aged reservoirs in this highly structural area.

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 development 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 southwest 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 starts just south of Edmonton, Alberta and extends north to Fort McMurray, Alberta and from northwest Alberta 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. 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.

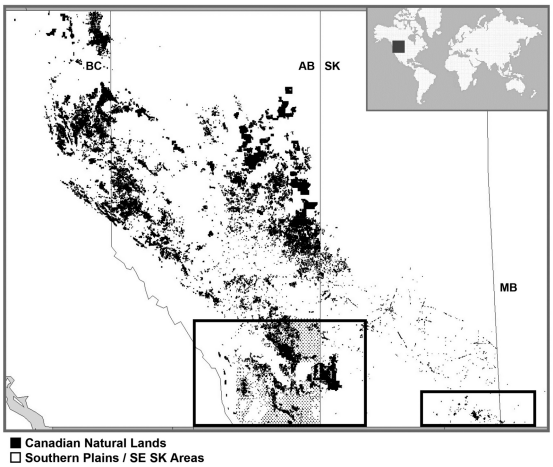
Included in the northern part of this region, approximately 200 miles north of Edmonton, Alberta are the Company's holdings at Pelican Lake. These assets produce Pelican Lake heavy crude oil from the Wabasca formation with gravities of 12°-17° API. Production expenses are low due to the absence of sand 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.

The Company has two 100% owned thermal SAGD facilities in the Kirby area located near Lac La Biche, Alberta with infrastructure and total plant processing capacity of 80,000 bbl/d.

The Company has a 100% interest in the operating thermal SAGD assets 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.

Southern Plains and Southeast Saskatchewan

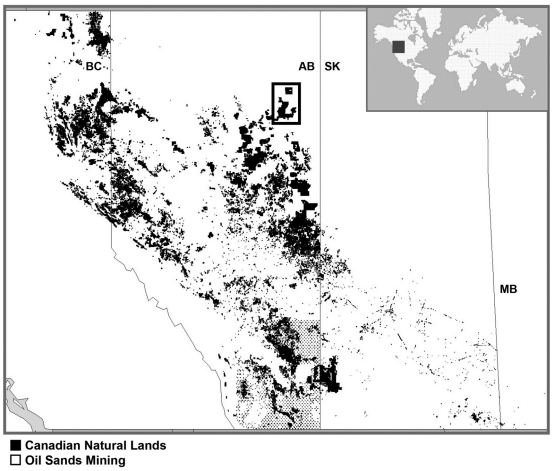


The Southern Plains region is principally located south of the Northern Plains region to the United States border and extending into western Saskatchewan.

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. In 2021, the Company completed an acquisition of a 5% net carried interest on an existing Company oil sands lease from which Horizon production is currently derived.

The oil sands resource at Horizon Oil Sands 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, which is accessible by private road and private airstrip, 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.

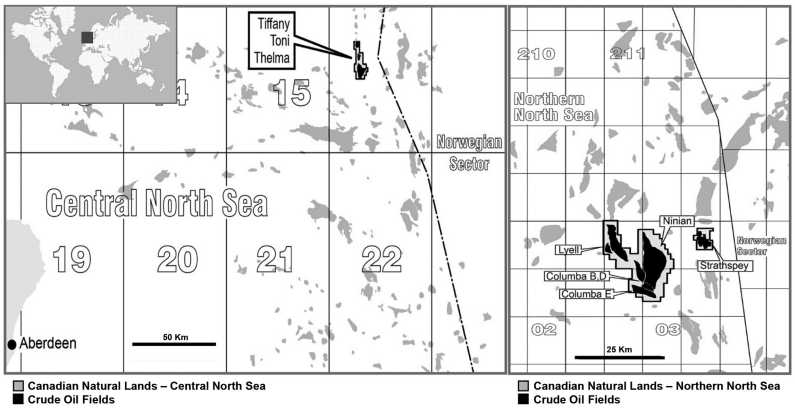
In 2018, the Company acquired the Joslyn oil sands project, adding to the Company's total oil sands mining and upgrading reserves. This incorporation of the Joslyn leases (now, Horizon South) to the mine plan will allow mining to continue south of the previously existing Horizon leases with opportunity 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 approximately 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 2021, the Company produced from 8 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 Strathspey, Columba and Lyell fields where the Company operates with working interests of 91.6% to 100%.

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).

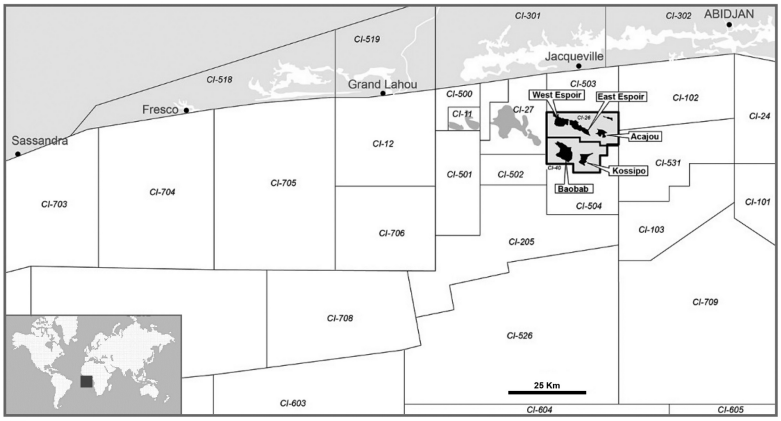
The Company receives tariff revenue from third parties for the processing of crude oil and natural gas through certain processing facilities.

The decommissioning activities at the Banff and Kyle fields commenced in the second quarter of 2020 with cessation of production occurring in June of 2020. The decommissioning activities are targeted to be substantially completed by 2024.

The Company commenced abandonment of the Ninian North Platform in the second quarter of 2017. In 2021, the decommissioning activities advanced with dismantling and disposal of the platform topsides. The decommissioning activities are targeted to be substantially complete in 2024.

Offshore Africa

Côte d'Ivoire

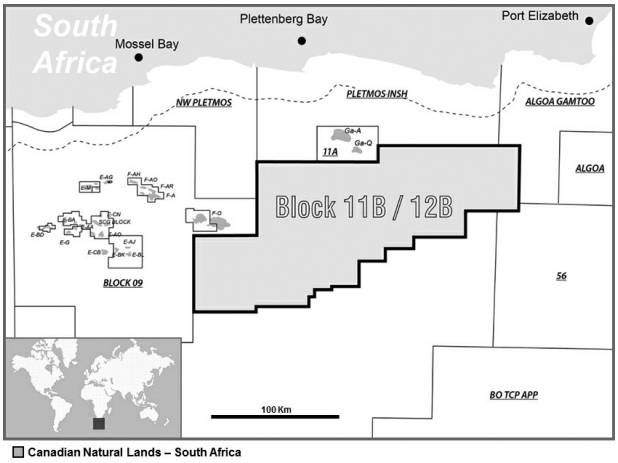


The Company owns interests in two licences offshore Côte d'Ivoire.

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 divested a 50% interest in the exploration right in a farm-out transaction 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 on the Block and subsequently announced the discovery of natural gas and condensate from that prospect. In 2020, the operator completed the drilling and testing of the Luiperd exploratory well on the Block and subsequently announced the discovery of natural gas and condensate on that prospect. The operator is currently preparing a development plan and production right application, which will be submitted in 2022. Additional cash payments will be due to the Company after the grant of a production right.

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, 2021.

Producing	Natural Gas Wells		Crude Oil Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	24,395	19,820.3	10,119	9,295.7	34,514	29,116.0
British Columbia	2,046	1,908.9	166	151.5	2,212	2,060.4
Saskatchewan	10,024	9,197.2	2,250	1,304.3	12,274	10,501.5
Manitoba	—	—	137	120.2	137	120.2
Total Canada	36,465	30,926.4	12,672	10,871.7	49,137	41,798.1
North Sea UK Sector	1	1.0	48	47.5	49	48.5
Offshore Africa						
Côte d'Ivoire	—	—	26	15.1	26	15.1
Total Company	36,466	30,927.4	12,746	10,934.3	49,212	41,861.7

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, 2021.

Non-Producing	Natural Gas Wells		Crude Oil Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	9,951	8,071.7	13,595	12,302.1	23,546	20,373.8
British Columbia	2,567	2,238.0	530	465.0	3,097	2,703.0
Saskatchewan	1,054	987.0	3,403	2,801.2	4,457	3,788.2
Manitoba	—	—	167	113.5	167	113.5
Northwest Territories	95	22.5	—	—	95	22.5
Total Canada	13,667	11,319.2	17,695	15,681.8	31,362	27,001.0
United States Louisiana	—	—	2	0.4	2	0.4
North Sea UK Sector	2	2.0	28	25.3	30	27.3
Offshore Africa						
Côte d'Ivoire	—	—	14	8.1	14	8.1
Total Company	13,669	11,321.2	17,739	15,715.6	31,408	27,036.8

Properties With No Attributed Reserves

The following table summarizes the Company's unproved property as of December 31, 2021.

Country (thousands of acres)	Gross	Net
Canada	22,705	18,293
US	9	3
North Sea UK Sector	54	52
Côte d'Ivoire	92	53
South Africa	4,002	800
Total Company	**26,861**	**19,202**

Where the Company holds interests in different formations under the same surface area pursuant to separate leases, the acreage for each lease is included in the gross and net amounts.

Canadian Natural has approximately 0.50 million net acres attributed to the North America properties which are currently expected to expire by December 31, 2022.

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.

2021 COSTS INCURRED IN CRUDE OIL, NATURAL GAS AND NGLs ACTIVITIES

($ millions)	North America	North Sea	Offshore Africa	Total
Property Acquisitions				
Proved	1,371	—	—	1,371
Unproved	26	—	—	26
Exploration	4	—	8	12
Development	4,301	208	48	4,557
	5,702	208	56	5,966
Add: Net non-cash and other costs [(1)]	(1,293)	(35)	6	(1,322)
Costs Incurred	4,409	173	62	4,644

(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, 2021. Total success rate for 2021, excluding service and stratigraphic test wells, was 99%.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Canada – Exploration and Production				
Crude Oil	21	21.0	127	122.5
Natural Gas	—	—	62	49.0
Dry	—	—	1	1.0
Service	—	—	5	5.0
Stratigraphic	—	—	—	—
Total	21	21.0	195	177.5
Canada – Oil Sands Mining & Upgrading				
Service	—	—	11	10.1
Stratigraphic	—	—	469	377.8
Total	—	—	480	387.9
Total Canada	21	21.0	675	565.4
North Sea UK Sector				
Crude Oil	—	—	6	5.9
Total International	—	—	6	5.9
Company Total	21	21.0	681	571.3

2022 ACTIVITY

Safe, effective and efficient operations will continue to be a focus of the Company in 2022. In January 2022, the Company released its 2022 base capital budget, which is targeted at approximately $3,600 million, and the Company targets to deploy incremental strategic growth capital of approximately $700 million. The $3,600 million budgeted for 2022 is primarily allocated to production growth of approximately 60,000 BOE/d derived primarily from production growth in E&P operations. The remaining $700 million is allocated to long life low decline assets which add incremental annual production in 2023 and beyond as well as disciplined year over year near-term growth. Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, to respond to price volatility, changes in project returns and the balancing of project risks and time horizons. The 2022 production guidance is targeted between 1,270,000 BOE/d and 1,320,000 BOE/d.

The 2022 capital budget and production targets constitute forward-looking information. Refer to the "Advisory" section of this AIF for further details on forward-looking information.

PRODUCTION ESTIMATES

The following table summarizes the estimated 2022 company gross proved and probable daily production included in the estimates of proved reserves and probable reserves as of December 31, 2021 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)
TOTAL PROVED								
North America	40,481	61,517	50,755	246,818	420,240	1,761	53,126	1,166,418
North Sea	20,636					5		21,391
Offshore Africa	15,404					15		17,866
Total Company	76,521	61,517	50,755	246,818	420,240	1,780	53,126	1,205,675
TOTAL PROBABLE								
North America	3,757	5,494	2,026	399	22,910	178	6,714	71,007
North Sea	2,223					1		2,327
Offshore Africa	1,354					1		1,543
Total Company	7,334	5,494	2,026	399	22,910	180	6,714	74,877

Production History and Netbacks

	2021				
	Q1	Q2	Q3	Q4	Year Ended
North America Production and Netbacks by Product [1]					
Light and Medium Crude Oil [2]					
Average daily production (before royalties) (bbl/d)	41,703	45,122	43,903	49,425	45,056
Average daily sales volumes (before royalties) (bbl/d)	41,761	45,109	43,889	49,462	45,073
Netbacks ($/bbl)					
Sales price [3]	63.48	72.92	79.46	87.34	76.36
Transportation [4]	3.09	3.67	3.72	3.33	3.46
Royalties [5]	5.31	9.08	10.79	12.20	9.50
Production expenses [6]	25.92	22.59	24.10	21.35	23.38
Netback	**29.16**	**37.58**	**40.85**	**50.46**	**40.02**
Primary Heavy Crude Oil [2]					
Average daily production (before royalties) (bbl/d)	62,695	65,992	63,891	64,866	64,366
Average daily sales volumes (before royalties) (bbl/d)	61,342	65,156	65,144	64,577	64,067
Netbacks ($/bbl)					
Sales price [3]	54.24	64.24	68.72	75.47	65.88
Transportation [4]	4.65	4.43	4.38	4.63	4.52
Royalties [5]	7.13	9.43	10.58	11.00	9.58
Production expenses [6]	18.89	19.32	19.51	19.72	19.37
Netback	**23.57**	**31.06**	**34.25**	**40.12**	**32.41**
Pelican Lake Heavy Crude Oil [2]					
Average daily production (before royalties) (bbl/d)	55,498	55,212	53,923	52,963	54,390
Average daily sales volumes (before royalties) (bbl/d)	56,549	54,153	53,177	55,370	54,804
Netbacks ($/bbl)					
Sales price [3]	55.26	67.75	71.92	77.40	68.05
Transportation [4]	4.21	5.43	6.14	6.19	5.49
Royalties [5]	11.39	15.80	16.95	19.26	15.84
Production expenses [6]	7.38	6.90	5.90	6.78	6.75
Netback	**32.28**	**39.62**	**42.93**	**45.17**	**39.97**
Bitumen (Thermal Oil) [2]					
Average daily production (before royalties) (bbl/d)	267,530	258,551	248,113	263,110	259,284
Average daily sales volumes (before royalties) (bbl/d)	266,806	250,410	241,680	272,665	257,862
Netbacks ($/bbl)					
Sales price [3]	48.92	58.50	64.81	68.45	60.20
Transportation [4]	4.09	4.42	4.33	4.10	4.23
Royalties [5]	5.09	7.71	8.81	9.66	7.82
Production expenses [6]	11.40	11.78	12.24	13.08	12.14
Netback	**28.34**	**34.59**	**39.43**	**41.61**	**36.01**
Natural Gas					
Average daily production (before royalties) (MMcf/d) [7]	1,585	1,594	1,698	1,841	1,680
Netbacks ($/Mcf)					
Sales price [3]	3.41	3.13	4.12	5.33	4.05
Transportation [4]	0.47	0.48	0.44	0.42	0.45
Royalties [5]	0.16	0.12	0.22	0.35	0.22
Production expenses [6]	1.24	1.15	1.14	1.08	1.15
Netback	**1.54**	**1.38**	**2.32**	**3.48**	**2.23**
Natural Gas Liquids [2]					
Average daily production (before royalties) (bbl/d)	51,310	53,437	45,058	48,374	49,525
Average daily sales volumes (before royalties) (bbl/d)	51,310	53,437	45,058	48,374	49,525
Netbacks ($/bbl)					
Sales price [3]	40.02	41.37	48.71	61.19	47.59
Transportation [4]	1.55	1.74	2.02	1.87	1.79
Royalties [5]	4.80	6.16	6.75	9.94	6.88
Production expenses [6]	8.05	7.48	8.49	7.72	7.91
Netback	**25.62**	**25.99**	**31.45**	**41.66**	**31.01**

	2021				
	Q1	Q2	Q3	Q4	Year Ended
North Sea Production and Netbacks by Product [1]					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	19,959	16,458	16,294	17,860	17,633
Average daily sales volumes (before royalties) (bbl/d)	29,566	8,939	16,028	21,360	18,942
Netbacks ($/bbl)					
Sales price [3]	75.16	85.09	96.11	100.45	87.98
Transportation [4]	0.68	2.59	1.24	0.62	1.01
Royalties [5]	0.12	0.39	0.22	0.19	0.19
Production expenses [6]	42.24	63.65	55.90	64.96	54.13
Netback	**32.12**	**18.46**	**38.75**	**34.68**	**32.65**
Natural Gas					
Average daily production (before royalties) (MMcf/d) [7]	4	4	2	3	3
Netbacks ($/Mcf)					
Sales price [3]	2.57	2.58	3.75	3.20	2.94
Transportation [4]	—	—	—	—	—
Royalties [5]	—	—	—	—	—
Production expenses [6]	4.85	6.96	8.86	9.19	7.31
Netback	**(2.28)**	**(4.38)**	**(5.11)**	**(5.99)**	**(4.37)**
Offshore Africa Production and Netbacks by Product [1]					
Light and Medium Crude Oil					
Average daily production (before royalties) (bbl/d)	11,854	16,239	13,531	14,421	14,017
Average daily sales volumes (before royalties) (bbl/d)	10,843	17,932	19,402	5,624	13,452
Netbacks ($/bbl)					
Sales price [3]	80.00	85.78	91.73	75.42	85.71
Transportation [4]	—	—	—	—	—
Royalties [5]	3.57	3.74	4.27	4.10	3.94
Production expenses [6]	16.57	13.20	14.53	16.75	14.73
Netback	**59.86**	**68.84**	**72.93**	**54.57**	**67.04**
Natural Gas					
Average daily production (before royalties) (MMcf/d) [7]	9	16	8	13	12
Netbacks ($/Mcf)					
Sales price [3]	6.09	6.50	6.83	9.00	7.17
Transportation [4]	0.17	0.16	0.16	0.17	0.16
Royalties [5]	0.28	0.30	0.31	0.41	0.33
Production expenses [6]	4.99	3.37	5.76	4.52	4.41
Netback	**0.65**	**2.67**	**0.60**	**3.90**	**2.27**
Total Exploration and Production					
Barrels of Oil Equivalent (BOE) [8]					
Average daily production (before royalties) (BOE/d)	776,900	780,032	769,377	820,494	786,773
Average daily sales volumes (before royalties) (BOD/d)	784,528	764,157	769,041	826,906	786,227
Netbacks ($/BOE) [1]					
Sales price [3]	41.80	46.40	52.09	57.72	49.67
Transportation [4]	3.29	3.58	3.50	3.40	3.44
Royalties [5]	4.10	5.77	6.45	7.48	5.98
Production expenses [6]	12.20	11.42	11.91	12.33	11.98
Netback	**22.21**	**25.63**	**30.23**	**34.51**	**28.27**
Oil Sands Mining and Upgrading Production and Netback [1]					
SCO					
Average daily production (before royalties) (bbl/d) [9]	468,803	361,707	468,126	493,406	448,133
Average daily sales volumes (before royalties) (bbl/d)	469,953	366,843	467,772	483,972	447,230
Netbacks ($/bbl)					
Sales price [3] [10]	64.60	76.19	81.54	88.48	77.95
Transportation [4]	1.10	1.26	1.14	1.33	1.21
Royalties [5] [11]	2.88	5.92	8.21	9.16	6.62
Production expenses [6]	19.82	25.46	19.86	19.55	20.91
Netback	**40.80**	**43.55**	**52.33**	**58.44**	**49.21**

Notes to Production History and Netback Tables

(1) Netback is a non-GAAP financial measure that represents the net cash flows provided from core activities after the impact of all costs associated with bringing a product to market, on a per unit basis. The Company considers netback a key measure in evaluating its performance as it demonstrates the efficiency and profitability of the Company's activities. The netback calculations include the non-GAAP financial measures: realized price and transportation. Refer to the discussion of netbacks in the 'Non-GAAP and Other Financial Measures" section of the Company's annual MD&A for the year ended December 31, 2021, dated March 2, 2022, for additional non-GAAP disclosure.

(2) Component of North America Exploration and Production crude oil and NGLs production and sales.

(3) Calculated as product sales, less blending expenses, divided by respective sales volumes.

(4) Calculated as transportation expense divided by respective sales volumes.

(5) Calculated as royalties divided by respective sales volumes.

(6) Calculated as production expense divided by respective sales volumes.

(7) Natural gas production volumes approximate sales volumes.

(8) Barrels of oil equivalent sales include total Exploration and Production crude oil, NGLs, and natural gas sales.

(9) Oil Sands Mining and Upgrading production is net of mined diesel produced and consumed at Horizon.

(10) SCO sales price is net of feedstock and blending costs.

(11) Royalty expense in the Oil Sands Mining and Upgrading segment is calculated based on bitumen royalties expensed during the period.

Selected Financial Information

($ millions, except per common share amounts)			**2021**		2020
Product sales [1]		**$**	**32,854**	$	17,491
Crude oil and NGLs		**$**	**29,256**	$	15,579
Natural gas		**$**	**2,716**	$	1,478
Net earnings		**$**	**7,664**	$	(435)
Per common share	– basic	**$**	**6.49**	$	(0.37)
	– diluted	**$**	**6.46**	$	(0.37)
Adjusted net earnings from operations [2]		**$**	**7,420**	$	(756)
Per common share	– basic [3]	**$**	**6.28**	$	(0.64)
	– diluted [3]	**$**	**6.25**	$	(0.64)
Cash flows from operating activities		**$**	**14,478**	$	4,714
Adjusted funds flow [2]		**$**	**13,733**	$	5,200
Per common share	– basic [3]	**$**	**11.63**	$	4.40
	– diluted [3]	**$**	**11.57**	$	4.40
Total assets		**$**	**76,665**	$	75,276
Total long-term liabilities		**$**	**32,298**	$	37,818
Cash flows used in investing activities		**$**	**3,703**	$	2,819
Net capital expenditures [2]		**$**	**4,908**	$	3,206

Notes to Selected Financial Information

(1) Further details related to product sales are disclosed in note 22 to the Company's audited consolidated financial statements for the year ended December 31, 2021.

(2) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's annual MD&A for the year ended December 31, 2021, dated March 2, 2022.

(3) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's annual MD&A for the year ended December 31, 2021, dated March 2, 2022.

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.

	2021	2020	2019
Cash dividends declared per common share	**$ 2.00**	$ 1.70	$ 1.50

On March 2, 2022, the Board of Directors approved an increase in the quarterly dividend to $0.75 per common share, beginning with the dividend payable on April 5, 2022. On November 3, 2021, the Board of Directors approved an increase in the quarterly dividend to $0.5875 per common share, beginning with the dividend payable on January 5, 2022. On March 3, 2021, the Board of Directors approved an increase in the quarterly dividend to $0.47 per common share, beginning with the dividend payable on April 5, 2021. On March 4, 2020, the Board of Directors approved an increase in the quarterly dividend to $0.425 per common share. On March 6, 2019, the Board of Directors approved an increase in the quarterly dividend to $0.375 per common share.

Description of Capital Structure

COMMON SHARES

The Company is authorized to issue an unlimited number of common shares, without nominal or par value. Holders of common shares are entitled to one vote per share at a meeting of shareholders of Canadian Natural, to receive such dividends as declared by the Board of Directors on the common shares and to receive pro-rata the remaining property and assets of the Company upon its dissolution or winding-up, subject to any rights having priority over the common shares.

PREFERRED SHARES

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

CREDIT RATINGS

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

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

	Senior Unsecured Debt Securities	Commercial Paper	Outlook/Trend (1)
Moody's Investors Service, Inc. ("Moody's")	Baa2	P-2	Stable
S&P Global Ratings ("S&P") (2)	BBB-	A-3	Stable
DBRS Limited ("DBRS")	BBB (high)	—	Stable

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

(2) In 2021, S&P adjusted their industry risk for the oil and gas sector due to prospective volatility and margin pressures related to future energy transition, and the impact on potential profitability.

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 lead to a weakened capacity of the obligor to meet its financial commitments on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the rating categories. An S&P rating outlook assesses the potential direction of a long-term credit rating over the intermediate term, typically six months to two years. A "Negative", "Positive" or "Developing" outlook indicates a higher likelihood of a rating change during that time period. A "Stable" outlook indicates a low likelihood of a rating change during that time period. In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions, however, an outlook is not necessarily a precursor of a rating change or future CreditWatch action. S&P credit ratings on commercial paper are on a short-term debt rating scale that ranges from A-1 to D, representing the range of such securities rated from highest to lowest quality. A rating of A-2 by S&P indicates that the obligor is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in the highest rating category, but the obligor's capacity to meet its financial commitment on these obligations is satisfactory.

DBRS' credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the DBRS rating system, debt securities rated BBB are of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, though may be vulnerable to future events. All rating categories other than AAA and D also contain subcategories "(high)" and "(low)" which indicate the relative standing within such rating category. The absence of either a "(high)" or "(low)" designation indicates the rating is in the middle of the category. The rating trend is DBRS' opinion regarding the outlook for the rating in question, with rating trends falling into one of three categories "Positive", "Stable", or "Negative". The rating trend indicates the direction in which DBRS considers the rating may move if present circumstances continue, or in certain cases, unless challenges are addressed.

The credit ratings accorded to the Company's debt securities and commercial paper by the rating agencies are not recommendations to purchase, hold or sell the debt securities or commercial paper inasmuch as such ratings do not comment as to 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.

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 2021.

	2021 Monthly Historical Trading on TSX			
Month	High	Low	Close	Volume Traded (Shares)
January	$ 34.75	$ 28.67	$ 28.89	87,455,587
February	$ 37.79	$ 28.84	$ 34.71	93,627,137
March	$ 41.05	$ 35.12	$ 38.85	258,757,214
April	$ 39.72	$ 36.23	$ 37.31	94,052,510
May	$ 42.84	$ 37.32	$ 42.36	94,985,136
June	$ 46.36	$ 41.95	$ 45.00	212,245,503
July	$ 46.07	$ 38.60	$ 41.17	81,029,230
August	$ 42.56	$ 37.82	$ 41.75	84,248,112
September	$ 46.99	$ 40.69	$ 46.31	198,858,984
October	$ 54.02	$ 46.06	$ 52.60	97,480,304
November	$ 55.44	$ 49.85	$ 52.24	101,767,750
December	$ 55.59	$ 48.42	$ 53.45	164,364,229

On March 3, 2021, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the TSX to purchase, by way of a normal course issuer bid ("NCIB"), up to 59,278,474 common shares being approximately 5.0% of its issued and outstanding common shares as at February 28, 2021 for the purpose of repurchasing a number of common shares approximately equal to the number of options exercised throughout the year in order to minimize or eliminate dilution for shareholders. For the year ended December 31, 2021, the Company purchased 33,644,400 common shares at a weighted average price of $46.98 per common share. Subsequent to year-end, up to and including March 10, 2022, the Company purchased 12 million shares at a weighted average price of $66.15 per common share.

On March 2, 2022, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the TSX to purchase, by way of a Normal Course Issuer Bid, up to 10.0% of the public float (as determined in accordance with the rules of the TSX) of its issued and outstanding common shares as at February 28, 2022. Any purchases will be made through facilities of the TSX, alternative Canadian trading platforms, and the NYSE.

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 16, 2022 incorporated herein by reference.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Catherine M. Best, FCPA, ICD.D Calgary, Alberta Canada	Director [1][2] (age 68)	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 Infrastructure Solutions Ltd. She is also a member of the Board of the Alberta Children's Hospital Foundation, The Wawanesa Mutual Insurance Company and the Calgary Stampede Foundation.
M. Elizabeth Cannon, Ph.D., O.C. Calgary, Alberta Canada	Director [3][4][5] (age 59)	Corporate director. She is currently President Emerita 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 Chair and Director (age 62)	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.
Dawn L. Farrell Calgary, Alberta Canada	Director [1][3][4] (age 62)	Corporate director. Prior to her retirement in 2021, she was President and Chief Executive Officer of TransAlta Corporation since 2012, having previously served as Chief Operating Officer and Executive Vice-President, Commercial Operations. Currently serving on the board of directors of Portland General Electric and The Chemours Company (Chair). She is also Chancellor of Mount Royal University.
Christopher L. Fong Calgary, Alberta Canada	Director [3][5] (age 72)	Corporate director. He has served continuously as a director of the Company since November 2010. He is currently serving on the board of directors of Computer Modelling Group Ltd.
Ambassador Gordon D. Giffin Atlanta, Georgia U.S.A.	Director [1][4] (age 72)	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.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Wilfred A. Gobert Calgary, Alberta Canada	Director [1][2][4] (age 74)	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	Director [5][6] (age 64)	Corporate director. He was an officer of the Company until May 5, 2020. He has served continuously as a director of the Company since August 2006.
Tim S. McKay Calgary, Alberta Canada	President and Director [3] (age 60)	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 74)	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 72)	Corporate director. Prior thereto, Chairman, Optiom Inc. (private insurance company) since 2015; 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 65)	Chair and Chief Executive Officer of NRStor Inc., an energy storage project developer of energy storage technologies. She has served as a director of the Corporation continuously since November 2014. She currently serves as Chancellor of Cape Breton University and as a director of Liberty Mutual Insurance Group and a board member of numerous non-profit organizations. Currently serving on the board of directors of Air Canada and Saputo Inc.
Troy J.P. Andersen Calgary, Alberta Canada	Senior Vice-President, Canadian Conventional Field Operations (age 43)	Officer of the Company.
Calvin J. Bast Calgary, Alberta Canada	Senior Vice-President, Production (age 47)	Officer of the Company since May 2018. Prior there to Thermal Production Manager from November 2012 to February 2017, Conventional Exploitation Manager from March 2017 to April 2018, and most recently Vice President - Production East from May 2018 to February 2022.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Bryan C. Bradley Calgary, Alberta Canada	Senior Vice-President, Marketing (age 56)	Officer of the Company.
Trevor J. Cassidy Calgary, Alberta Canada	Senior Vice-President, Thermal (age 48)	Officer of the Company.
Darren M. Fichter Calgary, Alberta Canada	Chief Operating Officer, Exploration and Production (age 51)	Officer of the Company.
Jay E. Froc Calgary, Alberta Canada	Senior Vice-President, Oil Sands Mining and Upgrading (age 56)	Officer of the Company.
Dwayne F. Giggs Calgary, Alberta Canada	Senior Vice-President, Exploration (age 45)	Officer of the Company since April 2021. Prior thereto, District Geologist, Heavy Oil Central from December 2013 to January 2017, Exploration Manager from January 2017 to April 2021, and most recently Vice President - Exploration West from April 2021 to November 2021.
Ronald K. Laing Calgary, Alberta Canada	Senior Vice-President, Corporate Development and Land (age 52)	Officer of the Company.
Erin L. Lunn Calgary, Alberta Canada	Vice-President, Land (age 47)	Officer of the Company since February 2022. Prior thereto Land Manager, Negotiations from July 2016 to February 2022.
Pamela McIntyre Calgary, Alberta Canada	Senior Vice-President, Safety, Risk Management and Innovation (age 59)	Officer of the Company.
Paul M. Mendes Calgary, Alberta Canada	Vice-President, Legal, General Counsel and Corporate Secretary (age 56)	Officer of the Company.
Kyle G. Pisio Calgary, Alberta Canada	Vice-President, Drilling, Completions and Asset Retirement (age 40)	Officer of the Company since June 2021. Prior thereto Manager, Completions Engineering from July 2016 to June 2021.

Name	Position Presently Held	Principal Occupation During Past 5 Years
Roy D. Roth Calgary, Alberta Canada	Vice President Facilities and Pipelines (age 48)	Officer of the Company since July 2018. Prior thereto, Facilities Engineering Manager from April 2011 to July 2018, Vice President – Thermal Production from July 2010 to Sept 2021, and most recently Vice President – Facilities and Pipelines from Sept 2021 to present.
Mark A. Stainthorpe Calgary, Alberta Canada	Chief Financial Officer and Senior Vice-President, Finance (age 44)	Officer of the Company since March 2018. Prior thereto, 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 56)	Officer of the Company.
Robin S. Zabek Calgary, Alberta Canada	Senior Vice-President, Exploitation (age 50)	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 retired from the Company as Executive Vice-Chairman on May 5, 2020 and is considered a non-management, non-independent director of the Company.

All directors stand for election at each Annual Meeting of the Company's Shareholders. All of the current directors, except Ms. Dawn L. Farrell, were elected to the Board at the last Annual Meeting of the Company's Shareholders held on May 6, 2021. Ms. Farrell will stand for election at the Annual and Special Meeting of the Company's Shareholders to be held on May 5, 2022 having been appointed to the Board on August 4, 2021.

As at December 31, 2021, the directors and executive officers of the Company, as a group, beneficially owned or controlled or directed, directly or indirectly, in the aggregate, approximately 26 million common shares (approximately 2%) of the total outstanding common shares of 1,169 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 the Company is not aware of any such legal proceedings that are contemplated.

During the year ended December 31, 2021, 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 2, 2022 in respect of the Company’s consolidated financial statements as at December 31, 2021 and December 31, 2020 and for each of the three years in the period ended December 31, 2021 and the Company’s internal control over financial reporting as at December 31, 2021. 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 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, D. A. Tuer and Ms. D. L Farrell, 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 Sarbane-Oxley Act of 2002.

Ms. D. L. Farrell holds a Bachelor of Commerce with a major in Finance and a Master of Arts degree in Economics, both from the University of Calgary, and she attended the Advanced Management Program at Harvard University. She has over 35 years of experience in the electric energy industry, having most recently retired as President and Chief Executive Officer of TransAlta in 2021. Her prior roles at TransAlta included: Chief Operating Officer, Executive Vice-President, Commercial Operations and Development; Executive Vice-President, Corporate Development; Executive Vice-President, Independent Power Projects; and Vice-President, Energy Marketing and IPP Development. Prior to TransAlta, Ms. Farrell served as Executive Vice-President, Generation and Executive Vice-President Engineering, Aboriginal Relations and Generation at BC Hydro. Throughout her career, Ms. Farrell actively supervised principal accounting and financial officers, controllers and other accountants, internal auditors and other individuals performing similar functions, developing an understanding of generally accepted accounting principles, internal controls, procedures for financial reporting and audit committee functions in respect of business organizations. As a result, Ms. Farrell developed an understanding of accounting issues and complexities that would be generally comparable to those presented by the Company's financial statements. Ms. Farrell 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 the continued 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.

Mr. D. A. Tuer's education and experience relevant to the performance of his responsibilities as an audit committee member is derived from professional training and a business career as a chief executive officer in a large publicly traded company which provided experience in analyzing and evaluating financial statements and supervising persons engaged in the preparation, analysis and evaluation of financial statements of publicly traded companies. He has gained an understanding of internal controls and procedures for financial reporting through oversight of those functions, and the understanding of audit committee functions through his years of chief executive involvement.

Auditor Service Fees

The Audit Committee of the Board of Directors in 2021 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)	2021	2020
Audit fees	**$ 2,310**	$ 2,207
Audit related fees	**463**	412
Tax fees	**305**	258
All other fees	**17**	12
Total	**$ 3,095**	$ 2,889

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 and Special Meeting and Information Circular dated March 16, 2022 in connection with the Annual and Special Meeting of Shareholders of Canadian Natural to be held on May 5, 2022 which information is incorporated herein by reference. Additional financial information and discussion of the affairs of the Company and the business environment in which the Company operates is provided in the Company's MD&A, comparative Consolidated Financial Statements and Supplementary Oil & Gas Information for the most recently completed fiscal year ended December 31, 2021 respectively, as set forth in the 2021 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, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, 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 total 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, 2021, 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, 2021	Canada and USA	—	61,010	5,131	66,140
Sproule International Limited	December 31, 2021	United Kingdom and Offshore Africa	—	6,214	—	6,214
Total			**—**	67,224	5,131	72,355

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 as of December 31, 2021.
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 2, 2022

Original Signed By
SIGNED "GARY R. FINNIS" "Professional Stamp"
Gary R. Finnis, P.Eng.
Senior Manager, Engineering
Date: March 2, 2022
APEGA ID 62965

Validation
Sproule Associates Limited
APEGA Permit #00417
Original Signed By
SIGNED "STEVEN GOLKO"
Steven Golko, P.Eng.
Senior VP, Reservoir Services
Date: March 2, 2022
RM APEGA ID 80169

Original Signed By
SIGNED "ALEXEY ROMANOV"
Alexey Romanov, Ph.D., P.Geo
Senior Geoscientist
Date: March 2, 2022
RM APEGA ID 112313

Sproule International Limited
Calgary, Alberta, Canada,
March 2, 2022

Original Signed By
SIGNED "MEGHAN KLEIN" "Professional Stamp"
Meghan Klein, P.Eng.
Senior Manager, Engineering
Date: March 2, 2022
APEGA ID 84981

Validation
Sproule International Limited
APEGA Permit #06151
Original Signed By
SIGNED "SCOTT W. PENNELL"
Scott W. Pennell, P.Eng.
Chief Operating Officer
March 2, 2022
RM APEGA ID 94501

Original Signed By
SIGNED "ALEC KOVALTCHOUK"
Alec Kovaltchouk, P.Geo.
VP, Geoscience
DATE: March 2, 2022
RM APEGA ID 72150

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, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, 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 total 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, 2021, 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 Ltd.	December 31, 2021	Canada	—	73,553	—	73,553
Total			—	**73,553**	—	**73,553**

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 Ltd., Calgary, Alberta, Canada, March 2, 2022

"*Original Signed By*"

Tim R. Freeborn, P.Eng.
Vice President and Chief Financial Officer

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 2nd day of March, 2022

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 the management of risk related thereto;

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

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

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

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

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

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

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

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

(f) to review and consider management's assessment and report on the Corporation's cyber risk and cybersecurity measures implemented by the Corporation in response to those risks;

(g) to establish procedures for:

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

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

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

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

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

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

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



CANADIAN NATURAL RESOURCES LIMITED

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2021 AND 2020

March 2, 2022

Consolidated Financial Statements

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Management's Report

The accompanying consolidated financial statements of Canadian Natural Resources Limited (the "Company") and all other information contained elsewhere in this Annual Report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies described in the accompanying notes. Where necessary, management has made informed judgements and estimates in accounting for transactions that were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board as appropriate in the circumstances. The financial information presented elsewhere in the Annual Report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized and recorded, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to audit and provide their independent audit opinions on the following:

- the Company's consolidated financial statements as at and for the year ended December 31, 2021; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2021.

Their report is presented with the consolidated financial statements.

The Board of Directors (the "Board") is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board exercises this responsibility through the Audit Committee of the Board, which is comprised entirely of independent directors. The Audit Committee meets with management and the independent auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board for approval. The consolidated financial statements have been approved by the Board on the recommendation of the Audit Committee.

SIGNED "TIM S. MCKAY"	SIGNED "MARK STAINTHORPE"	SIGNED "VICTOR DAREL"
TIM S. MCKAY	**MARK STAINTHORPE**, **CFA**	**VICTOR DAREL, CPA, CA**
President	Chief Financial Officer and Senior Vice-President, Finance	Vice-President, Finance and Principal Accounting Officer

Calgary, Alberta, Canada
March 2, 2022

Management's Assessment of Internal Control over Financial Reporting

Management of Canadian Natural Resources Limited (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as defined in Rules 13a-15(f) and 15d-15(f) under the United States Securities Exchange Act of 1934, as amended.

Management, including the Company's President and the Company's Chief Financial Officer and Senior Vice-President, Finance, performed an assessment of the Company's internal control over financial reporting based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on the assessment, management has concluded that the Company's internal control over financial reporting is effective as at December 31, 2021. Management recognizes that all internal control systems have inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has provided an opinion on the Company's internal control over financial reporting as at December 31, 2021, as stated in their accompanying Report of Independent Registered Public Accounting Firm.

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

Calgary, Alberta, Canada
March 2, 2022

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Canadian Natural Resources Limited

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Canadian Natural Resources Limited and its subsidiaries (together, the "Company") as of December 31, 2021 and 2020, and the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2021, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and its financial performance and its cash flows for each of the three years in the period ended December 31, 2021 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control – Integrated Framework (2013) issued by the COSO.

Basis for Opinions

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

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

The impact of crude oil and natural gas reserves on property, plant and equipment assets in the North America Exploration and Production segment

As described in Notes 1, 4 and 7 to the Company's consolidated financial statements, the property, plant and equipment ("PP&E") balance in the North America Exploration and Production segment was $25.1 billion as of December 31, 2021. Depletion, depreciation and amortization ("DD&A") expense for the North America Exploration and Production segment was $3.5 billion for the year ended December 31, 2021. In accordance with the Company's accounting policies, crude oil and natural gas properties in the North America Exploration and Production segment, excluding certain major components, are depleted using the unit-of-production method based on proved reserves. Estimates of the Company's crude oil and natural gas reserves are based on engineering data, estimated future prices and production costs, expected future rates of production and the timing and amount of future development expenditures. Management utilizes third party specialists, specifically independent qualified reserve evaluators, to evaluate and review its estimates of crude oil and natural gas reserves. These estimates are utilized for the calculation of DD&A expense.

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

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of internal controls in the North America Exploration and Production segment relating to management's estimates of the Company's crude oil and natural gas reserves and the calculation of DD&A expense. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the estimates of crude oil and natural gas reserves used to determine DD&A expense for the North America Exploration and Production segment. As a basis for using this work, the specialists' qualifications were understood, and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of data used by the specialists and an evaluation of the specialists' findings. The procedures performed also included, among other, evaluating whether the assumptions used by management's specialists related to estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures were reasonable considering the current and past performance of the Company, consistency with industry pricing forecasts, and whether they were consistent with evidence obtained in other areas of the audit, as applicable. Additionally, these procedures also included testing the unit-of-production rates used to calculate DD&A expense.

SIGNED "PricewaterhouseCoopers LLP"

Chartered Professional Accountants

Calgary, Canada
March 2, 2022

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

Consolidated Balance Sheets

As at December 31, (millions of Canadian dollars)	Note	2021	2020
ASSETS			
Current assets			
Cash and cash equivalents		**$ 744**	$ 184
Accounts receivable		**3,111**	2,190
Current income taxes receivable		**—**	309
Inventory	5	**1,548**	1,060
Prepaids and other		**195**	231
Investments	9	**309**	305
Current portion of other long-term assets	10	**35**	82
		5,942	4,361
Exploration and evaluation assets	6	**2,250**	2,436
Property, plant and equipment	7	**66,400**	65,752
Lease assets	8	**1,508**	1,645
Other long-term assets	10	**565**	1,082
		$ 76,665	$ 75,276
LIABILITIES			
Current liabilities			
Accounts payable		**$ 803**	$ 667
Accrued liabilities		**3,064**	2,346
Current income taxes payable		**1,607**	—
Current portion of long-term debt	11	**1,000**	1,343
Current portion of other long-term liabilities	8,12	**948**	722
		7,422	5,078
Long-term debt	11	**13,694**	20,110
Other long-term liabilities	8,12	**8,384**	7,564
Deferred income taxes	13	**10,220**	10,144
		39,720	42,896
SHAREHOLDERS' EQUITY			
Share capital	14	**10,168**	9,606
Retained earnings		**26,778**	22,766
Accumulated other comprehensive (loss) income	15	**(1)**	8
		36,945	32,380
		$ 76,665	$ 75,276

Commitments and contingencies (note 20).

Approved by the Board of Directors on March 2, 2022.

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

Consolidated Statements of Earnings (Loss)

For the years ended December 31, (millions of Canadian dollars, except per common share amounts)	Note		2021		2020		2019
Product sales	22	$	**32,854**	$	17,491	$	24,394
Less: royalties			**(2,797)**		(598)		(1,523)
Revenue			**30,057**		16,893		22,871
Expenses							
Production			**7,152**		6,280		6,277
Transportation, blending and feedstock			**6,604**		4,498		4,699
Depletion, depreciation and amortization	7,8		**5,724**		6,046		5,546
Administration			**366**		391		344
Share-based compensation	12		**514**		(82)		223
Asset retirement obligation accretion	12		**185**		205		190
Interest and other financing expense	18		**711**		756		836
Risk management activities	19		**36**		(7)		77
Foreign exchange gain			**(127)**		(275)		(570)
Gain on acquisitions	7		**(478)**		(217)		—
Income from North West Redwater Partnership	10		**(400)**		—		—
(Gain) loss from investments	9,10		**(141)**		171		293
			20,146		17,766		17,915
Earnings (loss) before taxes			**9,911**		(873)		4,956
Current income tax expense (recovery)	13		**1,848**		(257)		434
Deferred income tax expense (recovery)	13		**399**		(181)		(894)
Net earnings (loss)		$	**7,664**	$	(435)	$	5,416
Net earnings (loss) per common share							
Basic	17	$	**6.49**	$	(0.37)	$	4.55
Diluted	17	$	**6.46**	$	(0.37)	$	4.54

Consolidated Statements of Comprehensive Income (Loss)

For the years ended December 31, (millions of Canadian dollars)		2021		2020		2019
Net earnings (loss)	$	**7,664**	$	(435)	$	5,416
Items that may be reclassified subsequently to net earnings						
Net change in derivative financial instruments designated as cash flow hedges						
Unrealized income, net of taxes of $2 million (2020 – $2 million, 2019 – $13 million)		**15**		13		99
Reclassification to net earnings (loss), net of taxes of $ 1 million (2020 – $2 million, 2019 – $5 million)		**(7)**		(15)		(41)
		8		(2)		58
Foreign currency translation adjustment						
Translation of net investment		**(17)**		(24)		(146)
Other comprehensive loss, net of taxes		**(9)**		(26)		(88)
Comprehensive income (loss)	$	**7,655**	$	(461)	$	5,328

Consolidated Statements of Changes in Equity

For the years ended December 31, (millions of Canadian dollars)	Note	2021	2020	2019
Share capital	14			
Balance – beginning of year		**$ 9,606**	$ 9,533	$ 9,323
Issued upon exercise of stock options		**707**	108	360
Previously recognized liability on stock options exercised for common shares		**139**	21	53
Purchase of common shares under Normal Course Issuer Bid		**(284)**	(56)	(203)
Balance – end of year		**10,168**	9,606	9,533
Retained earnings				
Balance – beginning of year		**22,766**	25,424	22,529
Net earnings (loss)		**7,664**	(435)	5,416
Dividends on common shares	14	**(2,355)**	(2,008)	(1,783)
Purchase of common shares under Normal Course Issuer Bid	14	**(1,297)**	(215)	(738)
Balance – end of year		**26,778**	22,766	25,424
Accumulated other comprehensive (loss) income	15			
Balance – beginning of year		**8**	34	122
Other comprehensive loss, net of taxes		**(9)**	(26)	(88)
Balance – end of year		**(1)**	8	34
Shareholders' equity		**$ 36,945**	$ 32,380	$ 34,991

Consolidated Statements of Cash Flows

For the years ended December 31, (millions of Canadian dollars)	Note	2021	2020	2019
Operating activities				
Net earnings (loss)		**$ 7,664**	$ (435)	$ 5,416
Non-cash items				
Depletion, depreciation and amortization		**5,724**	6,046	5,546
Share-based compensation		**514**	(82)	223
Asset retirement obligation accretion		**185**	205	190
Unrealized risk management loss (gain)		**19**	(39)	13
Unrealized foreign exchange gain		**(205)**	(116)	(548)
Gain on acquisitions		**(478)**	(217)	—
(Gain) loss from investments		**(132)**	185	321
Deferred income tax expense (recovery)		**399**	(181)	(894)
Realized foreign exchange loss (gain)		**118**	(166)	—
Other		**13**	(71)	(109)
Abandonment expenditures		**(307)**	(249)	(296)
Net change in non-cash working capital	21	**964**	(166)	(1,033)
Cash flows from operating activities		**14,478**	4,714	8,829
Financing activities				
(Repayment) issuance of bank credit facilities and commercial paper, net	11,21	**(6,151)**	338	2,025
Repayment of medium-term notes	11,21	**—**	(1,100)	(1,000)
(Repayment) issuance of US dollar debt securities	11,21	**(628)**	1,481	—
Settlement of long-term debt acquired	7	**(183)**	(397)	—
Proceeds on settlement of cross currency swaps		**—**	166	—
Payment of lease liabilities	8	**(209)**	(225)	(237)
Issue of common shares on exercise of stock options		**707**	108	360
Dividends on common shares		**(2,170)**	(1,950)	(1,743)
Purchase of common shares under Normal Course Issuer Bid		**(1,581)**	(271)	(941)
Cash flows used in financing activities		**(10,215)**	(1,850)	(1,536)
Investing activities				
Net expenditures on exploration and evaluation assets	6,21	**(1)**	(5)	(73)
Net expenditures on property, plant and equipment	7,22	**(4,492)**	(2,555)	(3,535)
Acquisition of Devon Canada Corporation assets	6,7	**—**	—	(3,412)
Proceeds from investment	9	**128**	—	—
Repayment of North West Redwater Partnership subordinated debt advances	10	**555**	124	—
Net change in non-cash working capital	21	**107**	(383)	(235)
Cash flows used in investing activities		**(3,703)**	(2,819)	(7,255)
Increase in cash and cash equivalents		**560**	45	38
Cash and cash equivalents – beginning of year		**184**	139	101
Cash and cash equivalents – end of year		**$ 744**	$ 184	$ 139
Interest paid on long-term debt, net		**$ 672**	$ 745	$ 865
Income taxes (received) paid		**$ (62)**	$ (29)	$ 445

Notes to the Consolidated Financial Statements

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

1. Accounting Policies

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

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

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

The Company was incorporated in Alberta, Canada. The address of its registered office is 2100, 855 - 2 Street S.W., Calgary, Alberta, Canada.

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

(A) PRINCIPLES OF CONSOLIDATION

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

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

Certain of the Company's activities are conducted through joint arrangements in which two or more parties have joint control. Where the Company has determined that it has a direct ownership interest in jointly controlled assets and obligations for the liabilities (a "joint operation"), the assets, liabilities, revenue and expenses related to the joint operation are included in the consolidated financial statements in proportion to the Company's interest. Where the Company has determined that it has an interest in jointly controlled entities (a "joint venture"), it uses the equity method of accounting. Under the equity method, the Company's initial and subsequent investments are recognized at cost and subsequently adjusted for the Company's share of the joint venture's income or loss, less distributions received. If the Company's share of the joint venture's loss equals or exceeds its interest in the joint venture, the Company discontinues recognizing its share of further losses. The Company resumes recognizing profits when its share of profits exceeds the accumulated share of losses not recognized.

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

(B) SEGMENTED INFORMATION

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

(C) CASH AND CASH EQUIVALENTS

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

(D) INVENTORY

Inventory is primarily comprised of product inventory, materials and supplies and other inventory, including emissions credits, and is carried at the lower of cost and net realizable value. Product inventory is comprised of crude oil held for sale, including pipeline linefill and crude oil stored in floating production, storage and offloading vessels ("FPSO"). Cost of product inventory consists of purchase costs, direct production costs, directly attributable overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Net realizable value for product inventory is determined by reference to forward prices. Cost for materials and supplies consists of purchase costs and is based on a first-in, first-out or an average cost basis. Net realizable value for materials and supplies and other inventory is determined by reference to current market prices. Emissions credit inventory generated in the normal course of business is initially measured in accordance with the Company's accounting policy for government grants.

(E) EXPLORATION AND EVALUATION ASSETS

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

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

Once the technical feasibility and commercial viability of E&E assets are determined and a development decision is made by management, the E&E assets are tested for impairment upon reclassification to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. An E&E asset is derecognized upon disposal or when no future economic benefits are expected to arise from its use. Any gain or loss arising on derecognition of the asset is recognized in net earnings within depletion, depreciation and amortization.

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

(F) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Assets under construction are not depleted or depreciated until available for their intended use.

Exploration and Production

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

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

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

Oil Sands Mining and Upgrading

Capitalized costs for the Oil Sands Mining and Upgrading segment are reported separately from the Company’s North America Exploration and Production segment. Capitalized costs include acquisition costs, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs.

Mine-related costs are depleted using the unit-of-production method based on proved reserves. Costs of the upgraders and related infrastructure located on the Horizon and AOSP sites are depreciated on the unit-of-production method based on the estimated productive capacity of the respective upgraders and related infrastructure. Other equipment is depreciated on a straight-line basis over its estimated useful life ranging from 2 to 20 years.

Midstream, Refining and Head Office

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

Useful lives

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

Derecognition

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

Major maintenance expenditures

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

Impairment

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

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

(G) BUSINESS COMBINATIONS

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

(H) OVERBURDEN REMOVAL COSTS

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

(I) CAPITALIZED BORROWING COSTS

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

(J) LEASES

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

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

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

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

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

Where the Company acts as the operator of a joint operation, the Company recognizes 100% of the related lease asset and lease liability. As the Company recovers its joint operation partners' share of the costs of the lease contract, these recoveries are recognized as other income in the consolidated statements of earnings.

(K) ASSET RETIREMENT OBLIGATIONS

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

(L) FOREIGN CURRENCY TRANSLATION

Functional and presentation currency

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

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

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

Transactions and balances

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

(M) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the sale of crude oil and NGLs and natural gas products is recognized when performance obligations in the sales contract are satisfied and it is probable that the Company will collect the consideration to which it is entitled. Performance obligations are generally satisfied at the point in time when the product is delivered to a location specified in a contract and control passes to the customer. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Contracts for sale of the Company's products generally have terms of less than a year, with certain contracts extending beyond one year. Contracts in North America generally specify delivery of crude oil and NGLs and natural gas throughout the term of the contract. Contracts in the North Sea and Offshore Africa generally specify delivery of crude oil at a point in time.

Sales of the Company's crude oil and NGLs and natural gas products to customers are made pursuant to contracts based on prevailing commodity pricing at or near the time of delivery and volumes of product delivered. Revenues are typically collected in the month following delivery and accordingly, the Company has elected to apply the practical expedient to not adjust consideration for the effects of a financing component. Purchases and sales of crude oil and NGLs and natural gas with the same counterparty, made to facilitate sales to customers or potential customers, that are entered into in contemplation of one another, are combined and recorded as non-monetary exchanges and measured at the net settlement amount.

Revenue in the consolidated statement of earnings represents the Company's share of product sales net of royalty payments to governments and other mineral interest owners. The Company discloses the disaggregation of revenues from sales of crude oil and NGLs and natural gas in the segmented information in note 22. Related costs of goods sold are comprised of production, transportation, blending and feedstock, and depletion, depreciation and amortization expenses. These amounts have been separately presented in the consolidated statements of earnings.

(N) PRODUCTION SHARING CONTRACTS

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

(O) INCOME TAX

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

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

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

Current income tax is calculated based on net earnings for the period, adjusted for items that are non-taxable or taxed in different periods, using income tax rates that are substantively enacted at each reporting date. Income taxes are recognized in net earnings or other comprehensive income, consistent with the items to which they relate.

(P) SHARE-BASED COMPENSATION

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

The Performance Share Unit ("PSU") plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met. PSUs vest three years from original grant date. The liability for PSUs is initially measured in reference to the Company's stock price and the number of awards expected to vest and is remeasured at each reporting period for changes in the fair value of the liability.

The unamortized costs of employer contributions to the Company's share bonus program are included in other long-term assets .

(Q) FINANCIAL INSTRUMENTS

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

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

Cash and cash equivalents, accounts receivable and certain other long-term assets are classified as financial assets at amortized cost since it is the Company's intention to hold these assets to maturity and the related cash flows are solely comprised of payments of principal and interest. Investments in publicly traded shares are classified as fair value through profit or loss. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as financial liabilities at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

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

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

Impairment of financial assets

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

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

(R) RISK MANAGEMENT ACTIVITIES

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

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

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

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

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

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

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

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

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

(S) GOVERNMENT GRANTS

The Company receives or is eligible for government grants, including emissions credits and grants introduced in response to the impact of the novel coronavirus ("COVID-19"). Government grants are recognized in net earnings when there is reasonable assurance that the Company will comply with the conditions attached to the grant and the grant will be received. Emissions performance and offset credits generated under the Alberta Technology Innovation and Emissions Reduction (“TIER”) regulation are initially recorded at the value prescribed by the Alberta TIER fund compliance rates in effect at the time the credits are recognized.

(T) COMPREHENSIVE INCOME (LOSS)

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

(U) PER COMMON SHARE AMOUNTS

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

(V) SHARE CAPITAL

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

(W) DIVIDENDS

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

2. Changes in Accounting Policies

In August 2020, the IASB issued Interest Rate Benchmark Reform (Phase 2) in response to the Financial Stability Board's mandated reforms to InterBank Offered Rates ("IBORs"), with financial regulators proposing that current IBOR benchmark rates be replaced by a number of new local currency denominated alternative benchmark rates. The Company adopted the amendments on January 1, 2021. Adoption of these amendments did not have a significant impact on the Company's financial statements.

3. Accounting Standards Issued But Not Yet Applied

In May 2020, the IASB issued amendments to IAS 16 “Property, Plant and Equipment” to require proceeds received from selling items produced while the entity is preparing the asset for its intended use to be recognized in net earnings, rather than as a reduction in the cost of the asset. The amendments were adopted January 1, 2022 and did not have a significant impact on the Company's consolidated financial statements.

In January 2020, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" to clarify that liabilities are classified as either current or non-current, depending on the existence of the substantive right at the end of the reporting period for an entity to defer settlement of the liability for at least twelve months after the reporting period. The amendments are effective January 1, 2023 with early adoption permitted. The amendments are required to be adopted retrospectively. The Company is assessing the impact of these amendments on its consolidated financial statements.

In February 2021 the IASB issued amendments to IAS 1 to require entities to disclose their material accounting policy information rather than their significant accounting policies. To support this amendment the IASB also amended IFRS Practice Statement 2 “Making Materiality Judgements”. The amendments are effective January 1, 2023 with earlier adoption permitted. The Company is assessing the impact of this amendment on its accounting policy disclosure.

In May 2021, the IASB issued amendments to IAS 12 "Income Taxes" to require companies to recognize deferred tax on particular transactions that, on initial recognition, give rise to equal amounts of taxable and deductible temporary differences. The amendments are effective January 1, 2023 with early adoption permitted. The amendments are required to be adopted retrospectively. The Company is assessing the impact of these amendments on its consolidated financial statements.

4. Critical Accounting Estimates and Judgements

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

(A) CRUDE OIL AND NATURAL GAS RESERVES

Purchase price allocations, depletion, depreciation and amortization, asset retirement obligations, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserves estimates are based on engineering data, estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations and judgements including the potential impact of climate related matters and in accordance with related government regulations. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information.

(B) ASSET RETIREMENT OBLIGATIONS

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

(C) INCOME TAXES

The Company is subject to income taxes in numerous legal jurisdictions. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

(D) FAIR VALUE OF DERIVATIVES AND OTHER FINANCIAL INSTRUMENTS

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

(E) PURCHASE PRICE ALLOCATIONS

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

(F) SHARE-BASED COMPENSATION

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

(G) IDENTIFICATION OF CGUs

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

(H) IMPAIRMENT OF ASSETS

The recoverable amount of a CGU or an individual asset has been determined as the higher of the CGUs' or the assets' fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available, including information on future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and operating costs, after-tax discount rates (currently ranging from 10% to 12%), and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

(I) LEASES

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

(J) CONTINGENCIES

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

(K) IMPACT OF COVID-19

For the year ended December 31, 2021, COVID-19 continued to have an impact on the global economy, including the oil and gas industry. Business conditions in 2021 continued to reflect the market uncertainty associated with COVID-19. The Company has taken into account the impacts of COVID-19 and the unique circumstances it has created in making estimates, assumptions and judgements in the preparation of these consolidated financial statements, and continues to monitor the developments in the business environment and commodity market. Actual results may differ from estimated amounts, and those differences may be material.

5. Inventory

		2021		2020
Product inventory	**$**	**535**	$	390
Materials, supplies and other		**1,013**		670
	$	**1,548**	$	1,060

6. Exploration and Evaluation Assets

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2019	$ 2,258	$ —	$ 69	$ 252	$ 2,579
Additions/Acquisitions	40	—	15	—	55
Transfers to property, plant and equipment	(194)	—	—	—	(194)
Derecognitions and other	(3)	—	—	—	(3)
Foreign exchange adjustments	—	—	(1)	—	(1)
At December 31, 2020	2,101	—	83	252	2,436
Additions/Acquisitions	**30**	**—**	**8**	**—**	**38**
Transfers to property, plant and equipment	**(73)**	**—**	**—**	**(150)**	**(223)**
Derecognitions and other	**(1)**	**—**	**—**	**—**	**(1)**
At December 31, 2021	**$ 2,057**	**$ —**	**$ 91**	**$ 102**	**$ 2,250**

On December 17, 2021, the Company completed the acquisition of all the issued and outstanding common shares of Storm Resources Ltd. ("Storm") for total cash consideration of $771 million, including $13 million of exploration and evaluation assets (note 7).

During 2020, the Company completed the acquisition of all the issued and outstanding shares of Painted Pony Energy Ltd. ("Painted Pony") for total cash consideration of $111 million, including $15 million of exploration and evaluation assets (note 7).

During 2019, the Company completed the acquisition of substantially all the assets of Devon Canada Corporation ("Devon") including thermal in situ and heavy crude oil assets, for total cash consideration of $3,412 million, including $91 million of exploration and evaluation assets (note 7).

7. Property, Plant and Equipment

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2019	$ 72,627	$ 7,296	$ 3,933	$ 45,016	$ 451	$ 466	$ 129,789
Additions/Acquisitions	1,789	104	94	1,328	6	19	3,340
Transfers from E&E assets	194	—	—	—	—	—	194
Derecognitions and other [1]	(521)	(3)	—	(634)	—	—	(1,158)
Disposals	(92)	—	—	—	—	—	(92)
Foreign exchange adjustments and other	—	(114)	(64)	—	—	—	(178)
At December 31, 2020	73,997	7,283	3,963	45,710	457	485	131,895
Additions/Acquisitions	**4,146**	**208**	**48**	**1,526**	**9**	**23**	**5,960**
Transfers from E&E assets	**73**	**—**	**—**	**150**	**—**	**—**	**223**
Derecognitions and other [1]	**(382)**	**3**	**—**	**(530)**	**—**	**—**	**(909)**
Foreign exchange adjustments and other	**—**	**(56)**	**(31)**	**—**	**—**	**—**	**(87)**
At December 31, 2021	**$ 77,834**	**$ 7,438**	**$ 3,980**	**$ 46,856**	**$ 466**	**$ 508**	**$ 137,082**
Accumulated depletion and depreciation							
At December 31, 2019	$ 46,577	$ 5,712	$ 2,712	$ 6,247	$ 153	$ 345	$ 61,746
Expense	3,676	247	161	1,668	15	25	5,792
Derecognitions and other [1]	(521)	(3)	—	(634)	—	—	(1,158)
Disposals	(63)	—	—	—	—	—	(63)
Foreign exchange adjustments and other	(28)	(103)	(51)	8	—	—	(174)
At December 31, 2020	49,641	5,853	2,822	7,289	168	370	66,143
Expense	**3,468**	**149**	**118**	**1,733**	**15**	**25**	**5,508**
Derecognitions and other [1]	**(382)**	**3**	**—**	**(530)**	**—**	**—**	**(909)**
Foreign exchange adjustments and other	**5**	**(54)**	**(17)**	**7**	**—**	**(1)**	**(60)**
At December 31, 2021	**$ 52,732**	**$ 5,951**	**$ 2,923**	**$ 8,499**	**$ 183**	**$ 394**	**$ 70,682**
Net book value							
- at December 31, 2021	**$ 25,102**	**$ 1,487**	**$ 1,057**	**$ 38,357**	**$ 283**	**$ 114**	**$ 66,400**
- at December 31, 2020	$ 24,356	$ 1,430	$ 1,141	$ 38,421	$ 289	$ 115	$ 65,752

(1) An asset is derecognized when no future economic benefits are expected to arise from its continued use or disposal.

As at December 31, 2021, the Company assessed the recoverability of its property, plant and equipment and its exploration and evaluation assets, and determined the carrying amounts of all of its cash generating units to be recoverable.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. During 2021, no interest was capitalized to property, plant and equipment (2020 – $24 million at a weighted average capitalization rate of 3.5%; 2019 – $53 million at a weighted average capitalization rate of 4.0%).

As at December 31, 2021, property, plant and equipment included project costs, not subject to depletion and depreciation, of $ 118 million in the Oil Sands Mining and Upgrading segment (2020 – $117 million in the Oil Sands Mining and Upgrading segment).

Acquisitions in the current and comparative years have been accounted for as business combinations using the acquisition method of accounting. Gains reported on the acquisitions represent the excess of the fair value of the net assets acquired compared to the total purchase consideration.

ACQUISITIONS IN 2021

Acquisition of Storm

On December 17, 2021, the Company completed the acquisition of all the issued and outstanding common shares of Storm for total cash consideration of $771 million. Storm is involved in the exploration for and development of natural gas and natural gas liquids in the Montney region of British Columbia.

The acquisition has been accounted for using the acquisition method of accounting. The allocation of the purchase price was based on management's best estimates of the fair value of the assets acquired and liabilities assumed as of the acquisition date. The below amounts are estimates, and may be subject to change based on the receipt of new information.

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

Property, plant and equipment	**$**	**1,114**
Exploration and evaluation assets		**13**
Working capital		**20**
Long-term debt		**(183)**
Asset retirement obligations		**(18)**
Other long-term liabilities		**(35)**
Deferred tax liability		**(140)**
Net assets acquired	**$**	**771**

In connection with the acquisition the Company assumed certain product transportation and processing commitments (note 20).

The impact of revenue and revenue, less production and transportation and blending expenses ("net operating income") generated by the acquisition from December 17, 2021 to December 31, 2021 was not significant. If the acquisition had been completed on January 1, 2021, the Company estimates that pro forma revenue would have increased by an additional $294 million and pro forma net operating income would have increased by an additional $205 million for the year ended December 31, 2021. Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have resulted had the acquisition actually occurred on January 1, 2021, or of future results. Pro forma results are based on available historical information for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition date.

Other Acquisitions in 2021

During 2021, the Company completed two acquisitions of gas producing assets and related processing infrastructure in the Montney region of British Columbia, including property, plant and equipment assets of $257 million and exploration and evaluation assets of $ 13 million, for cash consideration of $131 million. In connection with the acquisitions, the Company assumed asset retirement obligations of $ 58 million, other liabilities of $65 million, and recognized a deferred tax asset of $ 462 million. A gain of $ 478 million was recognized as a result of the acquisitions, representing the excess of the fair value of the net assets acquired compared with the total purchase consideration.

ACQUISITIONS IN 2020

Acquisition of Painted Pony

On October 6, 2020, the Company completed the acquisition of all the issued and outstanding common shares of Painted Pony for total cash consideration of $111 million.

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

Property, plant and equipment	$	750
Exploration and evaluation assets		15
Other long-term assets		204
Long-term debt		(397)
Asset retirement obligations		(13)
Other long-term liabilities		(442)
Deferred tax asset		211
Net assets acquired		328
Less: cash consideration		111
Gain on acquisition	$	217

In connection with the acquisition the Company assumed certain product transportation and processing commitments (note 20).

ACQUISITIONS IN 2019

Acquisition of Thermal in Situ and Primary Heavy Crude Oil Assets

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

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

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

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

As a result of the acquisition, during the year ended December 31, 2019, revenue increased by approximately $ 1,540 million and net operating income increased by approximately $590 million.

Other Acquisitions in 2019

During 2019, the Company acquired a number of producing crude oil and natural gas properties in the North America Exploration and Production segment for net cash consideration of $80 million and assumed associated asset retirement obligations of $ 20 million. No net deferred income tax liabilities were recognized and no pre-tax gains were recognized on these net transactions.

8. Leases

LEASE ASSETS

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2019	$ 1,166	$ 317	$ 182	$ 124	$ 1,789
Additions [1]	17	121	7	3	148
Depreciation	(124)	(53)	(51)	(26)	(254)
Derecognitions	(20)	(5)	(10)	—	(35)
Foreign exchange adjustments and other	(1)	(1)	—	(1)	(3)
At December 31, 2020	$ 1,038	$ 379	$ 128	$ 100	$ 1,645
Additions	**48**	**36**	**—**	**4**	**88**
Depreciation	**(110)**	**(57)**	**(27)**	**(22)**	**(216)**
Foreign exchange adjustments and other	**(2)**	**(4)**	**(2)**	**(1)**	**(9)**
At December 31, 2021	**$ 974**	**$ 354**	**$ 99**	**$ 81**	**$ 1,508**

(1) The acquisition of Painted Pony in 2020 included lease assets of $93 million (note 7).

LEASE ASSETS, BY SEGMENT

As at December 31, 2021 and 2020, the Company had the following lease assets by segment:

	2021	2020
Exploration and Production		
North America	**$ 308**	$ 345
North Sea	**1**	7
Offshore Africa	**101**	126
Oil Sands Mining and Upgrading	**1,027**	1,080
Head office	**71**	87
	$ 1,508	$ 1,645

LEASE LIABILITIES

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities at December 31, 2021 and 2020, were as follows:

	2021	2020
Lease liabilities	**$ 1,584**	$ 1,690
Less: current portion	**185**	189
	$ 1,399	$ 1,501

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

Other amounts included in net earnings and cash flows during 2021 and 2020 are provided below:

	2021	2020
Expenses relating to short-term leases [1]	**$ 450**	$ 409
Interest expense on lease liabilities	**$ 62**	$ 67
Variable lease payments not included in the measurement of lease liabilities	**$ 65**	$ 85
Total cash outflows for leases [2]	**$ 1,089**	$ 983

(1) During 2021, the Company capitalized $303 million (2020 - $197 million) of short-term leases as additions to property, plant and equipment.

(2) Comprised of cash outflows relating to lease liabilities, short-term leases, and variable lease payments.

9. Investments

As at December 31, 2021 and 2020, the Company had the following investments:

		2021		2020
Investment in PrairieSky Royalty Ltd.	**$**	**309**	$	228
Investment in Inter Pipeline Ltd.		**—**		77
	$	**309**	$	305

INVESTMENT IN PRAIRIESKY ROYALTY LTD.

The Company's investment of 22.6 million common shares of PrairieSky Royalty Ltd. ("PrairieSky") does not constitute significant influence, and is accounted for at fair value through profit or loss, measured at each reporting date. As at December 31, 2021 the market price per common share was $13.63 (December 31, 2020 – $10.09; December 31, 2019 – $15.23). As at December 31, 2021, the Company's investment in PrairieSky was classified as a current asset. PrairieSky is in the business of acquiring and managing oil and gas royalty income assets through indirect third-party oil and gas development.

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

		2021		2020		2019
(Gain) loss from investment	**$**	**(81)**	$	117	$	55
Dividend income		**(7)**		(9)		(17)
	$	**(88)**	$	108	$	38

INVESTMENT IN INTER PIPELINE LTD.

During 2021, in accordance with a third-party offer to purchase, the Company elected to take total cash proceeds of $ 128 million, or $20.00 per common share, in exchange for its 6.4 million common share investment in Inter Pipeline Ltd ("Inter Pipeline"). The Company's investment did not constitute significant influence, and was accounted for at fair value through profit or loss, measured at each reporting date. The market price per common share as at December 31, 2020 and December 31, 2019 was $11.87 and $22.54, respectively.

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

		2021		2020		2019
(Gain) loss from investment	**$**	**(51)**	$	68	$	(21)
Dividend income		**(2)**		(5)		(11)
	$	**(53)**	$	63	$	(32)

10. Other Long-Term Assets

		2021		2020
North West Redwater Partnership	**$**	**—**	$	555
Prepaid cost of service toll		**157**		162
Risk management (note 19)		**140**		136
Long-term inventory		**126**		121
Other [(1)]		**177**		190
		600		1,164
Less: current portion		**35**		82
	$	**565**	$	1,082

(1) The acquisition of Painted Pony in 2020 included physical sales contracts (note 7).

INVESTMENT IN NORTH WEST REDWATER PARTNERSHIP

The Company has a 50% equity investment in NWRP. NWRP operates a 50,000 barrels per day bitumen upgrader and refinery that processes approximately 12,500 barrels per day (25% toll payer) of bitumen feedstock for the Company and 37,500 barrels per day (75% toll payer) of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period (note 20). Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 22).

On June 30, 2021, the equity partners together with the toll payers, agreed to optimize the structure of NWRP to better align the commercial interests of the equity partners and the toll payers (the "Optimization Transaction"). As a result, North West Refining Inc. transferred its entire 50% partnership interest in NWRP to APMC. The Company's 50% equity interest remained unchanged.

Under the Optimization Transaction, the original term of the processing agreements was extended by 10 years from 2048 to 2058. NWRP retired higher cost subordinated debt, which carried interest rates of prime plus 6%, with lower cost senior secured bonds at an average rate of approximately 2.55%, reducing interest costs to NWRP and associated tolls to the toll payers. As such, NWRP repaid the Company's and APMC's subordinated debt advances of $555 million each. In addition, the Company received a $400 million distribution from NWRP during 2021.

To facilitate the Optimization Transaction, NWRP issued $500 million of 1.20% series L senior secured bonds due December 2023, $500 million of 2.00% series M senior secured bonds due December 2026, $1,000 million of 2.80% series N senior secured bonds due June 2031, and $600 million of 3.75% series O senior secured bonds due June 2051. Additionally, NWRP's existing $3,500 million syndicated credit facility was amended. The $2,000 million revolving credit facility was extended by three years to June 2024, and the $1,500 million non-revolving credit facility was reduced by $500 million to $1,000 million and extended by two years to June 2023. As at December 31, 2021, NWRP had borrowings of $1,981 million under the syndicated credit facility (December 31, 2020 – $2,866 million).

The assets, liabilities, partners' equity, product sales and equity loss related to NWRP at December 31, 2021 and 2020 were comprised as follows:

		2021		2020
Current assets	$	**280**	$	230
Non-current assets	$	**10,806**	$	11,098
Current liabilities	$	**798**	$	3,146
Non-current liabilities	$	**11,412**	$	8,488
Partners' equity [(1)]	$	**(1,124)**	$	(306)
Partners' equity [(1)] at Company's 50% interest	$	**(562)**	$	(153)
Revenue [(2)]	$	**1,168**	$	1,348
Net loss [(3)]	$	**18**	$	188

(1) In 2021, NWRP paid partnership distributions at 100% interest of $800 million.

(2) Included in NWRP's revenue for 2021 is $294 million (2020 – $174 million) paid by the Company for its 25% share of the refining toll.

(3) Included in the net loss for 2021 is the impact of depreciation and amortization expense of $278 million (2020 – $214 million) and interest and other financing expense of $412 million (2020 – $420 million).

The carrying value of the Company's interest in NWRP is $ nil, and as at December 31, 2021, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $562 million (2020 – $153 million). The unrecognized share of the equity loss from NWRP for 2021 was $9 million and partnership distributions were $400 million (2020 – unrecognized equity loss of $94 million; 2019 – recognized equity loss of $287 million and unrecognized equity loss of $59 million).

11. Long-Term Debt

	2021	2020
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ —**	$ 1,614
Medium-term notes		
3.31% debentures due February 11, 2022	**1,000**	1,000
1.45% debentures due November 16, 2023	**500**	500
3.55% debentures due June 3, 2024	**500**	500
3.42% debentures due December 1, 2026	**600**	600
2.50% debentures due January 17, 2028	**300**	300
4.85% debentures due May 30, 2047	**300**	300
	3,200	4,814
US dollar denominated debt, unsecured		
Bank credit facilities (December 31, 2021 – US$ 901 million; December 31, 2020 – US$3,953 million)	**1,140**	5,041
Commercial paper (December 31, 2021 – US$nil; December 31, 2020 – US$426 million)	**—**	544
US dollar debt securities		
3.45% due November 15, 2021 (US$ 500 million)	**—**	638
2.95% due January 15, 2023 (US$ 1,000 million)	**1,266**	1,276
3.80% due April 15, 2024 (US$ 500 million)	**633**	638
3.90% due February 1, 2025 (US$ 600 million)	**759**	765
2.05% due July 15, 2025 (US$ 600 million)	**759**	765
3.85% due June 1, 2027 (US$ 1,250 million)	**1,582**	1,595
2.95% due July 15, 2030 (US$ 500 million)	**633**	638
7.20% due January 15, 2032 (US$ 400 million)	**506**	510
6.45% due June 30, 2033 (US$ 350 million)	**443**	446
5.85% due February 1, 2035 (US$ 350 million)	**443**	446
6.50% due February 15, 2037 (US$ 450 million)	**570**	574
6.25% due March 15, 2038 (US$ 1,100 million)	**1,392**	1,403
6.75% due February 1, 2039 (US$ 400 million)	**506**	510
4.95% due June 1, 2047 (US$ 750 million)	**949**	957
	11,581	16,746
Long-term debt before transaction costs and original issue discounts, net	**14,781**	21,560
Less: original issue discounts, net [1]	**15**	18
transaction costs [1] [2]	**72**	89
	14,694	21,453
Less: current portion of commercial paper	**—**	544
current portion of other long-term debt [1] [2]	**1,000**	799
	$ 13,694	$ 20,110

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

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

BANK CREDIT FACILITIES AND COMMERCIAL PAPER

As at December 31, 2021, the Company had undrawn bank credit facilities of $ 6,098 million. Additionally, the Company had in place fully drawn term credit facilities of $1,150 million. Details of these facilities are described below. The Company also has certain other dedicated credit facilities supporting letters of credit.

- a $100 million demand credit facility;
- a $1,000 million term credit facility maturing February 2023;
- a $1,150 million non-revolving term credit facility maturing February 2023;
- a $2,495 million revolving syndicated credit facility, with $ 70 million maturing June 2022, and $ 2,425 million maturing June 2024;
- a $2,495 million revolving syndicated credit facility, with $ 70 million maturing June 2023, and $ 2,425 million maturing June 2025; and
- a £5 million demand credit facility related to the Company's North Sea operations.

Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, SOFR, US base rate or Canadian prime rate.

During 2021, the Company extended both of its $ 2,425 million revolving credit facilities originally maturing June 2022 and June 2023, to June 2024 and June 2025, respectively and increased each by $70 million. In accordance with the terms of the extension, and by mutual agreement, $70 million of the original revolving credit facilities were not extended and will mature upon the original maturity date of June 2022 and June 2023, respectively. The revolving syndicated credit facilities are extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.

During 2021, the $1,000 million non-revolving term credit facility originally due February 2022, was extended to February 2023. Additionally in 2021, the facility was fully repaid and amended to allow for a re-draw of the full $1,000 million until March 31, 2022.

During 2021, the Company repaid $ 1,500 million of the $2,650 million non-revolving term credit facility due February 2023, reducing the outstanding balance to $1,150 million.

During 2019, the Company entered into a $ 3,250 million non-revolving term credit facility with an original maturity of June 2022, to finance the acquisition of assets from Devon (note 7). During 2021, the outstanding balance of $3,088 million was repaid and the facility was cancelled.

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

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at December 31, 2021 was 0.8% (December 31, 2020 – 1.1%), and on total long-term debt outstanding for the year ended December 31, 2021 was 3.5% (December 31, 2020 – 3.5%).

As at December 31, 2021, letters of credit and guarantees aggregating to $ 513 million were outstanding (December 31, 2020 – $ 489 million).

MEDIUM-TERM NOTES

During 2021, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $ 3,000 million of medium-term notes in Canada, which expires in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

During 2020, the Company issued $ 500 million of 1.45% medium-term notes due November 2023 and $ 300 million of 2.50% medium-term notes due January 2028.

During 2020, the Company repaid $ 1,000 million of 2.89% medium term notes and $ 900 million of 2.05% medium term notes.

US DOLLAR DEBT SECURITIES

During 2021, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$ 3,000 million of debt securities in the United States, which expires in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

During 2021, the Company repaid US$ 500 million of 3.45% debt securities.

During 2020, the Company issued US$ 600 million of 2.05% notes due July 2025 and US$ 500 million of 2.95% notes due July 2030.

SCHEDULED DEBT REPAYMENTS

Scheduled debt repayments are as follows:

Year		Repayment
2022	$	1,000
2023	$	2,906
2024	$	1,133
2025	$	1,518
2026	$	600
Thereafter	$	7,624

12. Other Long-Term Liabilities

		2021		2020
Asset retirement obligations	**$**	**6,806**	$	5,861
Lease liabilities (note 8)		**1,584**		1,690
Share-based compensation		**489**		160
Risk management (note 19)		**85**		160
Transportation and processing contracts [(1)]		**241**		270
Other [(2)]		**127**		145
		9,332		8,286
Less: current portion		**948**		722
	$	**8,384**	$	7,564

(1) The acquisition of Painted Pony in 2020 included product transportation and processing obligations (note 7).

(2) Includes $48 million (2020 – $72 million) related to the acquisition of the Joslyn oil sands project in 2018, payable in annual installments of $25 million.

ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 4.0% (2020 – 3.7%; 2019 – 3.8%) and inflation rates of up to 2% (December 31, 2020 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

		2021		2020		2019
Balance – beginning of year	**$**	**5,861**	$	5,771	$	3,886
Liabilities incurred		**5**		5		15
Liabilities acquired, net		**76**		13		198
Liabilities settled		**(307)**		(249)		(296)
Asset retirement obligation accretion		**185**		205		190
Revision of cost and timing estimates		**1,716**		(134)		412
Change in discount rates		**(723)**		253		1,412
Foreign exchange adjustments		**(7)**		(3)		(46)
Balance – end of year		**6,806**		5,861		5,771
Less: current portion		**249**		184		208
	$	**6,557**	$	5,677	$	5,563

Segmented Asset Retirement Obligations

	2021	2020
Exploration and Production		
North America	**$ 4,021**	$ 2,899
North Sea	**821**	787
Offshore Africa	**170**	174
Oil Sands Mining and Upgrading	**1,793**	1,999
Midstream and Refining	**1**	2
	$ 6,806	$ 5,861

SHARE-BASED COMPENSATION

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

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

	2021	2020	2019
Balance – beginning of year	**$ 160**	$ 297	$ 124
Share-based compensation expense (recovery)	**514**	(82)	223
Cash payment for stock options surrendered and PSUs vested	**(48)**	(39)	(2)
Transferred to common shares	**(139)**	(21)	(53)
Other	**2**	5	5
Balance – end of year	**489**	160	297
Less: current portion	**329**	119	227
	$ 160	$ 41	$ 70

Included within share-based compensation liability as at December 31, 2021 was $ 90 million (2020 – $49 million; 2019 – $62 million) related to PSUs granted to certain executive employees.

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

	2021	2020	2019
Fair value	**$ 16.98**	$ 3.47	$ 7.88
Share price	**$ 53.45**	$ 30.59	$ 42.00
Expected volatility	**35.5%**	39.8%	26.7%
Expected dividend yield	**4.4%**	5.6%	3.6%
Risk free interest rate	**1.1%**	0.3%	1.7%
Expected forfeiture rate	**4.7%**	4.3%	4.3%
Expected stock option life (1)	**4.2 years**	4.3 years	4.4 years

(1) At original time of grant.

The intrinsic value of vested stock options at December 31, 2021 was $ 112 million (2020 – $11 million; 2019 – $75 million).

13. Income Taxes

The provision for income tax was as follows:

Expense (recovery)		2021		2020		2019
Current corporate income tax – North America	**$**	**1,841**	$	(245)	$	354
Current corporate income tax – North Sea		**7**		(4)		112
Current corporate income tax – Offshore Africa		**21**		17		44
Current PRT [(1)] – North Sea		**(34)**		(31)		(89)
Other taxes		**13**		6		13
Current income tax		**1,848**		(257)		434
Deferred corporate income tax		**399**		(181)		(895)
Deferred PRT – North Sea		**—**		—		1
Deferred income tax		**399**		(181)		(894)
Income tax	**$**	**2,247**	$	(438)	$	(460)

(1) Petroleum Revenue Tax.

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

		2021		2020		2019
Canadian statutory income tax rate		**23.2%**		24.1%		26.5%
Income tax provision at statutory rate	**$**	**2,298**	$	(211)	$	1,313
Effect on income taxes of:						
UK PRT and other taxes		**(21)**		(25)		(76)
Impact of deductible UK PRT and other taxes on corporate income tax		**11**		11		32
Foreign and domestic tax rate differentials		**(11)**		(52)		(48)
Non-taxable portion of capital gains		**(26)**		(10)		(65)
Stock options exercised for common shares		**98**		(25)		47
Income tax rate and other legislative changes		**—**		—		(1,618)
Non-taxable gain on corporate acquisitions		**(110)**		(52)		—
Revisions arising from prior year tax filings		**16**		(62)		(41)
Change in unrecognized capital loss carryforward asset		**(26)**		(10)		(65)
Other		**18**		(2)		61
Income tax	**$**	**2,247**	$	(438)	$	(460)

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

		2021		2020
Deferred income tax liabilities				
Property, plant and equipment and exploration and evaluation assets	$	**12,254**	$	11,922
Lease assets		**349**		380
Investments		**35**		14
Investment in North West Redwater Partnership		**850**		767
Unrealized risk management activities		**12**		—
Unrealized foreign exchange gain on long-term debt		**14**		—
Other		**78**		8
		13,592		13,091
Deferred income tax assets				
Asset retirement obligations		**(1,719)**		(1,495)
Lease liabilities		**(363)**		(388)
Share-based compensation		**(22)**		(12)
Loss carryforwards		**(1,268)**		(1,032)
Unrealized foreign exchange loss on long-term debt		**—**		(20)
		(3,372)		(2,947)
Net deferred income tax liability	$	**10,220**	$	10,144

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

		2021		2020		2019
Property, plant and equipment and exploration and evaluation assets	$	**184**	$	(158)	$	(775)
Lease assets		**(30)**		(11)		414
Unrealized foreign exchange on long-term debt		**34**		29		55
Unrealized risk management activities		**19**		(8)		(14)
Asset retirement obligations		**(213)**		(13)		(317)
Lease liabilities		**25**		6		(418)
Share-based compensation		**(10)**		4		(11)
Loss carryforwards		**202**		(182)		170
Investments		**21**		(22)		(10)
Investment in North West Redwater Partnership		**83**		174		179
Deferred PRT		**—**		—		1
Other		**84**		—		(168)
	$	**399**	$	(181)	$	(894)

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

		2021		2020		2019
Balance – beginning of year	$	**10,144**	$	10,539	$	11,451
Deferred income tax expense (recovery)		**399**		(181)		(894)
Deferred income tax expense included in other comprehensive loss		**1**		—		8
Foreign exchange adjustments		**(2)**		(3)		(26)
Business combinations (note 7)		**(322)**		(211)		—
Balance – end of year	$	**10,220**	$	10,144	$	10,539

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

During 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of this corporate income tax rate reduction, the Company's deferred corporate income tax liability decreased by $1,618 million for the year ended December 31, 2019. During 2020, the Government of Alberta substantively enacted legislation to accelerate this reduction, lowering the corporate tax rate from 10% to 8%, effective July 1, 2020. This acceleration did not have a significant impact on the Company's deferred corporate income tax liability at December 31, 2020.

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

Deferred income tax assets are recognized for temporary differences to the extent that the realization of the related tax benefit through future taxable profits is probable. The Company has not recognized deferred income tax assets with respect to taxable capital loss carryforwards in excess of $1,000 million in North America, which can be carried forward indefinitely and only applied against future taxable capital gains. In addition, the Company has not recognized deferred income tax assets related to North American tax pools of approximately $1,050 million, which can only be claimed against income from certain oil and gas properties.

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

14. Share Capital

AUTHORIZED

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	2021		2020	
Issued Common Shares	**Number of shares** (thousands)	**Amount**	Number of shares (thousands)	Amount
Balance – beginning of year	**1,183,866**	**$ 9,606**	1,186,857	$ 9,533
Issued upon exercise of stock options	**18,147**	**707**	3,979	108
Previously recognized liability on stock options exercised for common shares	—	**139**	—	21
Purchase of common shares under Normal Course Issuer Bid	**(33,644)**	**(284)**	(6,970)	(56)
Balance – end of year	**1,168,369**	**$ 10,168**	1,183,866	$ 9,606

PREFERRED SHARES

Preferred shares are issuable in a series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions and conditions attached to the shares will be determined by the Board of Directors of the Company.

DIVIDEND POLICY

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

On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to $ 0.75 per common share, beginning with the dividend payable on April 5, 2022. On November 3, 2021, the Board of Directors approved a 25% increase in the quarterly dividend to $ 0.5875 per common share, from $0.47 per common share. On March 3, 2021, the Board of Directors approved an 11% increase in the quarterly dividend to $0.47 per common share, from $ 0.425 per common share. On March 4, 2020, the Board of Directors approved a 13% increase in the quarterly dividend to $0.425 per common share, from $ 0.375 per common share. On March 6, 2019, the Board of Directors approved a 12% increase in the quarterly dividend to $0.375 per common share, from $ 0.335 per common share. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

NORMAL COURSE ISSUER BID

On March 9, 2021, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), up to 59,278,474 common shares, over a 12-month period commencing March 11, 2021 and ending March 10, 2022.

For the year ended December 31, 2021, the Company purchased 33,644,400 common shares at a weighted average price of $ 46.98 per common share for a total cost of $1,581 million. Retained earnings were reduced by $ 1,297 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2021, the Company purchased 10,500,000 common shares at a weighted average price of $64.79 per common share for a total cost of $ 680 million.

On March 2, 2022, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the TSX to purchase, by way of a Normal Course Issuer Bid, up to 10% of the public float (as determined in accordance with the rules of the TSX) of its issued and outstanding common shares. Subject to acceptance of the Notice of Intention by the TSX, the purchases would be made through facilities of the TSX, alternative Canadian trading platforms, and the NYSE.

SHARE-BASED COMPENSATION – STOCK OPTIONS

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

The Option Plan is a "rolling 7%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 7% of the common shares outstanding from time to time.

The following table summarizes information relating to stock options outstanding at December 31, 2021 and 2020:

	2021		2020	
	Stock options (thousands)	**Weighted average exercise price**	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	**48,656**	**$ 37.53**	47,646	$ 38.04
Granted	**12,547**	**$ 34.39**	12,032	$ 32.89
Exercised for common shares	**(18,147)**	**$ 38.97**	(3,979)	$ 27.24
Surrendered for cash settlement	**(1,324)**	**$ 40.54**	(757)	$ 29.34
Forfeited	**(3,405)**	**$ 35.73**	(6,286)	$ 39.65
Outstanding – end of year	**38,327**	**$ 35.88**	48,656	$ 37.53
Exercisable – end of year	**7,841**	**$ 39.19**	17,970	$ 39.59

The range of exercise prices of stock options outstanding and exercisable at December 31, 2021 was as follows:

	Stock options outstanding			**Stock options exercisable**	
Range of exercise prices	**Stock options outstanding** (thousands)	**Weighted average remaining term** (years)	**Weighted average exercise price**	**Stock options exercisable** (thousands)	**Weighted average exercise price**
$20.76 – $24.99	2,697	3.31	$ 20.95	566	$ 20.76
$25.00 – $29.99	7,526	4.21	$ 29.21	1	$ 28.63
$30.00 – $34.99	2,726	3.58	$ 32.37	219	$ 32.56
$35.00 – $39.99	15,227	2.59	$ 37.46	3,148	$ 37.34
$40.00 – $44.99	7,679	2.74	$ 42.04	2,894	$ 43.23
$45.00 – $49.99	1,839	1.42	$ 45.19	1,013	$ 45.14
$50.00 – $54.24	633	5.83	$ 54.24	—	$ —
	38,327	3.06	$ 35.88	7,841	$ 39.19

15. Accumulated Other Comprehensive (Loss) Income

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

	2021	2020
Derivative financial instruments designated as cash flow hedges	**$ 77**	$ 69
Foreign currency translation adjustment	**(78)**	(61)
	$ (1)	$ 8

16. Capital Disclosures

The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined at each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current long-term debt and long-term debt less cash and cash equivalents divided by the sum of the carrying value of shareholders' equity plus current long-term debt and long-term debt less cash and cash equivalents. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2021, the ratio was within the target range at 27%.

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

		2021		2020
Long-term debt	**$**	**14,694**	$	21,453
Less: cash and cash equivalents		**744**		184
Long-term debt, net	**$**	**13,950**	$	21,269
Total shareholders' equity	**$**	**36,945**	$	32,380
Debt to book capitalization		**27%**		40%

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. At December 31, 2021, the Company was in compliance with this covenant.

17. Net Earnings Per Common Share

			2021		2020		2019
Weighted average common shares outstanding – basic (thousands of shares)			**1,181,250**		1,181,768		1,190,977
Effect of dilutive stock options (thousands of shares)			**5,307**		—		2,129
Weighted average common shares outstanding – diluted (thousands of shares)			**1,186,557**		1,181,768		1,193,106
Net earnings (loss)		**$**	**7,664**	$	(435)	$	5,416
Net earnings (loss) per common share	– basic	**$**	**6.49**	$	(0.37)	$	4.55
	– diluted	**$**	**6.46**	$	(0.37)	$	4.54

In 2021, the Company excluded 3,496,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share (year ended December 31, 2020 – 44,117,000; 2019 – 36,834,000).

18. Interest and Other Financing Expense

		2021		2020		2019
Interest and other financing expense:						
Long-term debt	**$**	**681**	$	785	$	895
Lease liabilities		**62**		67		70
Less: amounts capitalized on qualifying assets		**—**		(24)		(53)
Total interest and other financing expense		**743**		828		912
Total interest income and other		**(32)**		(72)		(76)
Net interest and other financing expense	**$**	**711**	$	756	$	836

19. Financial Instruments

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

	2021				
Asset (liability)	**Financial assets at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Cash and cash equivalents	**$ 744**	**$ —**	**$ —**	**$ —**	**$ 744**
Accounts receivable	**3,111**	**—**	**—**	**—**	**3,111**
Investments	**—**	**309**	**—**	**—**	**309**
Other long-term assets	**—**	**—**	**140**	**—**	**140**
Accounts payable	**—**	**—**	**—**	**(803)**	**(803)**
Accrued liabilities	**—**	**—**	**—**	**(3,064)**	**(3,064)**
Other long-term liabilities [1]	**—**	**(64)**	**(21)**	**(1,632)**	**(1,717)**
Long-term debt [2]	**—**	**—**	**—**	**(14,694)**	**(14,694)**
	$ 3,855	**$ 245**	**$ 119**	**$ (20,193)**	**$ (15,974)**

	2020				
Asset (liability)	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Cash and cash equivalents	$ 184	$ —	$ —	$ —	$ 184
Accounts receivable	2,190	—	—	—	2,190
Investments	—	305	—	—	305
Other long-term assets	555	—	136	—	691
Accounts payable	—	—	—	(667)	(667)
Accrued liabilities	—	—	—	(2,346)	(2,346)
Other long-term liabilities [1]	—	(52)	(108)	(1,762)	(1,922)
Long-term debt [2]	—	—	—	(21,453)	(21,453)
	$ 2,929	$ 253	$ 28	$ (26,228)	$ (23,018)

(1) Includes $1,584 million of lease liabilities (December 31, 2020 – $1,690 million) and $48 million of deferred purchase consideration payable over the nexttwo years (December 31, 2020 – $72 million).

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

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

	2021			
	Carrying amount	**Fair value**		
Asset (liability) [1] [2]		**Level 1**	**Level 2**	**Level 3** [4]
Investments [3]	**$ 309**	**$ 309**	**$ —**	**$ —**
Other long-term assets	**$ 140**	**$ —**	**$ 140**	**$ —**
Other long-term liabilities	**$ (133)**	**$ —**	**$ (85)**	**$ (48)**
Fixed rate long-term debt [6] [7]	**$ (13,554)**	**$ (15,420)**	**$ —**	**$ —**

	2020			
	Carrying amount	Fair value		
Asset (liability) [1] [2]		Level 1	Level 2	Level 3 [4] [5]
Investments [3]	$ 305	$ 305	$ —	$ —
Other long-term assets	$ 691	$ —	$ 136	$ 555
Other long-term liabilities	$ (232)	$ —	$ (160)	$ (72)
Fixed rate long-term debt [6] [7]	$ (14,254)	$ (16,598)	$ —	$ —

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

(2) There were no transfers between Level 1, 2 and 3 financial instruments.

(3) The fair values of the investments are based on quoted market prices.

(4) The fair value of the deferred purchase consideration included in other long-term liabilities is based on the present value of future cash payments.

(5) The fair value of NWRP subordinated debt was based on the present value of future cash receipts.

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

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

RISK MANAGEMENT

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

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

Asset (liability)	**2021**	2020
Derivatives held for trading		
Natural gas [1]	**$ (41)**	$ (45)
Crude oil [1]	**(10)**	—
Foreign currency forward contracts	**(13)**	(7)
Cash flow hedges		
Foreign currency forward contracts	**(21)**	(108)
Cross currency swaps	**140**	136
	$ 55	$ (24)
Included within:		
Current portion of other long-term assets	**$ 5**	$ 5
Current portion of other long-term liabilities	**(72)**	(131)
Other long-term assets	**135**	131
Other long-term liabilities	**(13)**	(29)
	$ 55	$ (24)

(1) Commodity financial instruments acquired from Storm and Painted Pony in 2021 and 2020, respectively.

During 2021, the Company's ineffectiveness from cash flow hedges was $ nil (2020 – loss of $1 million, 2019 – gain of $3 million).

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

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

Asset (liability)		**2021**		2020
Balance – beginning of year	**$**	**(24)**	$	178
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities [(1)]		**(12)**		(32)
Foreign exchange		**82**		(168)
Other comprehensive income (loss)		**9**		(2)
Balance – end of year		**55**		(24)
Less: current portion		**(67)**		(126)
	$	**122**	$	102

(1) Includes the fair value movement of commodity financial instruments included in acquisitions (note 7).

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

		2021		2020		2019
Net realized risk management loss	**$**	**17**	$	32	$	64
Net unrealized risk management loss (gain)		**19**		(39)		13
	$	**36**	$	(7)	$	77

FINANCIAL RISK FACTORS

a) Market risk

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

COMMODITY PRICE RISK MANAGEMENT

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases.

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

INTEREST RATE RISK MANAGEMENT

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2021, the Company had no significant interest rate swap contracts outstanding.

FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

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

At December 31, 2021 the Company had the following cross currency swap contract outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross Currency Swap	Jan 2022	–	Mar 2038	US$550	1.170	6.25 %	5.76 %

The cross currency swap derivative financial instrument was designated as a hedge at December 31, 2021 and was classified as a cash flow hedge.

In addition to the cross currency swap contracts noted above, at December 31, 2021, the Company had US$ 1,429 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$901 million designated as cash flow hedges.

During 2020, the Company settled the US$500 million cross currency swaps designated as cash flow hedges of the US$ 500 million 3.45% US dollar debt securities due November 2021. The Company realized cash proceeds of $166 million on settlement.

FINANCIAL INSTRUMENT SENSITIVITIES

The following table summarizes the annualized sensitivities of the Company's 2021 net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2021, resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those sensitivities disclosed in the Company's other continuous disclosure documents, are limited to the impact of changes in a specified variable applied to financial instruments only and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	2021 (1)		2020 (1)	
	Increase (decrease) to net earnings	**Increase (decrease) to other comprehensive income**	Increase (decrease) to net earnings	Increase (decrease) to other comprehensive income
Interest rate risk				
Increase interest rate 1%	**$ (13)**	**$ (29)**	$ (53)	$ (17)
Decrease interest rate 1%	**$ 13**	**$ 39**	$ 53	$ 20
Foreign currency exchange rate risk				
Weakening of the Canadian dollar by US$ 0.01	**$ (116)**	**$ —**	$ (126)	$ —
Strengthening of the Canadian dollar by US$ 0.01	**$ 114**	**$ —**	$ 123	$ —

(1) Based on the Company's contracted natural gas and crude oil financial instruments at December 31, 2021 and December 31, 2020, a movement of $0.10/MMBtu, $0.10/Mcf or $1.00/bbl would not have a significant impact on net earnings or other comprehensive income.

b) Credit risk

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

COUNTERPARTY CREDIT RISK MANAGEMENT

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At December 31, 2021, substantially all of the Company's accounts receivable were due within normal trade terms and the average expected credit loss was approximately 1% of the Company's accounts receivable balance (December 31, 2020 – 1%).

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. At December 31, 2021, the Company had net risk management assets of $140 million with specific counterparties related to derivative financial instruments (December 31, 2020 – $129 million). The carrying amount of financial assets approximates the maximum credit exposure.

c) Liquidity risk

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

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

The maturity dates of the Company's financial liabilities were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 803	$ —	$ —	$ —
Accrued liabilities	$ 3,064	$ —	$ —	$ —
Long-term debt [1]	$ 1,000	$ 2,906	$ 3,251	$ 7,624
Other long-term liabilities [2]	$ 282	$ 181	$ 430	$ 824
Interest and other financing expense [3]	$ 650	$ 583	$ 1,503	$ 3,971

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

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, $185 million; one to less than two years, $149 million; two to less than five years, $426 million; and thereafter, $824 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates at December 31, 2021.

20. Commitments and Contingencies

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2021:

	2022	2023	2024	2025	2026	Thereafter
Product transportation and processing [1] [2]	$ 967	$ 1,107	$ 914	$ 870	$ 816	$ 10,028
North West Redwater Partnership service toll [3]	$ 122	$ 123	$ 121	$ 119	$ 97	$ 3,671
Offshore vessels and equipment	$ 62	$ —	$ —	$ —	$ —	$ —
Field equipment and power	$ 25	$ 21	$ 21	$ 21	$ 21	$ 225
Other	$ 37	$ 27	$ 22	$ 20	$ 15	$ —

(1) Includes commitments pertaining to a 20-year product transportation agreement on the Trans Mountain Pipeline Expansion.

(2) The acquisition of Storm in 2021 and Painted Pony in 2020 included approximately $298 million and $2,400 million of product transportation and processing commitments, respectively (note 7).

(3) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $1,486 million of interest payable over the 40-year tolling period, ending in 2058 (note 10).

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

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

21. Supplemental Disclosure of Cash Flow Information

		2021		2020		2019
Changes in non-cash working capital:						
Accounts receivable	**$**	**(850)**	$	284	$	(1,310)
Current income tax (liabilities) assets		**1,918**		(295)		(164)
Inventory		**(487)**		98		(194)
Prepaids and other		**39**		(56)		2
Other long-term assets		**—**		(117)		117
Accounts payable		**80**		(147)		39
Accrued liabilities		**525**		(254)		265
Other long-term liabilities [(1)]		**(154)**		(62)		(23)
Net changes in non-cash working capital	**$**	**1,071**	$	(549)	$	(1,268)
Relating to:						
Operating activities	**$**	**964**	$	(166)	$	(1,033)
Investing activities		**107**		(383)		(235)
	$	**1,071**	$	(549)	$	(1,268)

		2021		2020		2019
Expenditures on exploration and evaluation assets	**$**	**12**	$	36	$	73
Net proceeds on sale of exploration and evaluation assets		**(11)**		(31)		—
Net expenditures on exploration and evaluation assets	**$**	**1**	$	5	$	73

(1) Included in Other long-term liabilities at December 31, 2021 is $48 million of deferred purchase consideration payable over the next two years (December 31, 2020 – $72 million; 2019 - $95 million).

The following table summarizes movements in the Company's liabilities arising from financing activities for the years' ended December 31, 2021 and 2020:

	Long-term debt	Cash flow hedges on US dollar debt securities	Lease liabilities	Liabilities from financing activities
At December 31, 2019	$ 20,982	$ (199)	$ 1,809	$ 22,592
Changes from financing cash flows:				
Issue of long-term debt, net [1]	719	—	—	719
Repayment of Painted Pony long-term debt	(397)	—	—	(397)
Proceeds on settlement of cross currency swaps	—	166	—	166
Payment of lease liabilities	—	—	(225)	(225)
Non-cash changes:				
Assumption of Painted Pony long-term debt	397	—	—	397
Lease additions	—	—	148	148
Changes in foreign exchange and fair value [2]	(248)	5	(42)	(285)
At December 31, 2020	21,453	(28)	1,690	23,115
Changes from financing cash flows:				
Repayment of long-term debt, net [1]	**(6,779)**	**—**	**—**	**(6,779)**
Repayment of Storm long-term debt	**(183)**	**—**	**—**	**(183)**
Payment of lease liabilities	**—**	**—**	**(209)**	**(209)**
Non-cash changes:				
Assumption of Storm long-term debt	**183**	**—**	**—**	**183**
Lease additions	**—**	**—**	**88**	**88**
Changes in foreign exchange and fair value [2]	**20**	**(91)**	**15**	**(56)**
At December 31, 2021	**$ 14,694**	**$ (119)**	**$ 1,584**	**$ 16,159**

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

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

22. Segmented Information

The Company's exploration and production activities are conducted in three geographic segments: North America, North Sea and Offshore Africa. These activities include the exploration, development, production and marketing of crude oil, natural gas liquids and natural gas. The Company's Oil Sands Mining and Upgrading activities are reported in a separate segment from exploration and production activities. Midstream and Refining activities include the Company's pipeline operations, an electricity co-generation system and NWRP.

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

	North America			North Sea			Offshore Africa		
(millions of Canadian dollars)	**2021**	2020	2019	**2021**	2020	2019	**2021**	2020	2019
Segmented product sales									
Crude oil and NGLs [1]	**$ 14,478**	$ 7,480	$ 9,679	**$ 607**	$ 417	$ 860	**$ 420**	$ 318	$ 632
Natural gas	**2,484**	1,242	1,150	**5**	12	57	**31**	42	67
Other income and revenue [2]	**119**	41	6	**(1)**	3	5	**7**	18	8
Total segmented product sales	**17,081**	8,763	10,835	**611**	432	922	**458**	378	707
Less: royalties	**(1,694)**	(503)	(998)	**(1)**	(1)	(2)	**(21)**	(16)	(42)
Segmented revenue	**15,387**	8,260	9,837	**610**	431	920	**437**	362	665
Segmented expenses									
Production	**2,963**	2,510	2,425	**383**	321	391	**91**	103	109
Transportation, blending and feedstock [1] [3]	**4,772**	3,393	2,935	**7**	15	19	**1**	1	2
Depletion, depreciation and amortization	**3,569**	3,780	3,326	**160**	277	308	**142**	190	242
Asset retirement obligation accretion	**101**	97	95	**21**	30	28	**6**	6	6
Risk management activities (commodity derivatives)	**29**	(20)	49	**—**	—	—	**—**	—	—
Gain on acquisitions	**(478)**	(217)	—	**—**	—	—	**—**	—	—
Income from NWRP	**—**	—	—	**—**	—	—	**—**	—	—
Equity loss from investments	**—**	—	—	**—**	—	—	**—**	—	—
Total segmented expenses	**10,956**	9,543	8,830	**571**	643	746	**240**	300	359
Segmented earnings (loss)	**$ 4,431**	$ (1,283)	$ 1,007	**$ 39**	$ (212)	$ 174	**$ 197**	$ 62	$ 306
Non–segmented expenses									
Administration									
Share-based compensation									
Interest and other financing expense									
Risk management activities (other)									
Foreign exchange gain									
(Gain) loss from investments									
Total non–segmented expenses									
Earnings (loss) before taxes									
Current income tax									
Deferred income tax									
Net earnings (loss)									

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

(2) Includes the sale of diesel and other refined products and other income, including government grants and recoveries associated with the joint operations partners' share of the costs of lease contracts.

(3) Includes a provision of $143 million relating to the Keystone XL pipeline project in the North America segment in 2020.

Inter-segment elimination and Other includes internal and corporate transportation and electricity charges. Production, processing and other purchasing and selling activities, that are not included in the preceding segments are also reported in the segmented information as Inter-segment eliminations and Other.

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

Oil Sands Mining and Upgrading			Midstream and Refining			Inter–segment elimination and Other			Total		
2021	2020	2019	**2021**	2020	2019	**2021**	2020	2019	**2021**	2020	2019
$ 14,033	$ 7,389	$ 11,340	**$ 78**	$ 83	$ 88	**$ (360)**	$ (108)	$ 351	**$ 29,256**	$ 15,579	$ 22,950
—	—	—	**—**	—	—	**196**	182	145	**2,716**	1,478	1,419
73	139	6	**681**	202	—	**3**	31	—	**882**	434	25
14,106	7,528	11,346	**759**	285	88	**(161)**	105	496	**32,854**	17,491	24,394
(1,081)	(78)	(481)	**—**	—	—	**—**	—	—	**(2,797)**	(598)	(1,523)
13,025	7,450	10,865	**759**	285	88	**(161)**	105	496	**30,057**	16,893	22,871
3,414	3,114	3,276	**234**	184	20	**67**	48	56	**7,152**	6,280	6,277
1,505	881	1,306	**550**	181	—	**(231)**	27	437	**6,604**	4,498	4,699
1,838	1,784	1,656	**15**	15	14	**—**	—	—	**5,724**	6,046	5,546
57	72	61	**—**	—	—	**—**	—	—	**185**	205	190
—	—	—	**—**	—	—	**—**	—	—	**29**	(20)	49
—	—	—	**—**	—	—	**—**	—	—	**(478)**	(217)	—
—	—	—	**(400)**	—	—	**—**	—	—	**(400)**	—	—
—	—	—	**—**	—	287	**—**	—	—	**—**	—	287
6,814	5,851	6,299	**399**	380	321	**(164)**	75	493	**18,816**	16,792	17,048
$ 6,211	$ 1,599	$ 4,566	**$ 360**	$ (95)	$ (233)	**$ 3**	$ 30	$ 3	**$ 11,241**	$ 101	$ 5,823
									366	391	344
									514	(82)	223
									711	756	836
									7	13	28
									(127)	(275)	(570)
									(141)	171	6
									1,330	974	867
									9,911	(873)	4,956
									1,848	(257)	434
									399	(181)	(894)
									$ 7,664	$ (435)	$ 5,416

CAPITAL EXPENDITURES [1]

	2021			2020		
	Net expenditures	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	**$ (7)**	**$ (36)**	**$ (43)**	$ (7)	$ (150)	$ (157)
Offshore Africa	**8**	**—**	**8**	12	3	15
Oil Sands Mining and Upgrading	**—**	**(150)**	**(150)**	—	—	—
	1	**(186)**	**(185)**	5	(147)	(142)
Property, plant and equipment						
Exploration and Production						
North America [3] [4]	**2,486**	**1,351**	**3,837**	999	371	1,370
North Sea	**173**	**38**	**211**	122	(21)	101
Offshore Africa	**54**	**(6)**	**48**	87	7	94
	2,713	**1,383**	**4,096**	1,208	357	1,565
Oil Sands Mining and Upgrading [5]	**1,747**	**(601)**	**1,146**	1,323	(629)	694
Midstream and Refining	**9**	**—**	**9**	5	1	6
Head office	**23**	**—**	**23**	19	—	19
	4,492	**782**	**5,274**	2,555	(271)	2,284
	$ 4,493	**$ 596**	**$ 5,089**	$ 2,560	$ (418)	$ 2,142

(1) This table provides a reconciliation of capitalized costs, reported in note 6 and note 7, to net expenditures reported in the investing activities section of the statements of cash flows. The reconciliation excludes the impact of foreign exchange adjustments.

(2) Derecognitions, asset retirement obligations, transfer of exploration and evaluation assets, and other fair value adjustments.

(3) Includes cash consideration paid of $771 million for the acquisition of Storm in 2021.

(4) Includes cash consideration paid of $111 million for the acquisition of Painted Pony in 2020.

(5) Net expenditures includes the acquisition of a 5% net carried interest on an existing oil sands lease during 2021, capitalized interest and share-based compensation.

SEGMENTED ASSETS

		2021	2020
Exploration and Production			
North America	**$**	**30,645**	$ 29,094
North Sea		**1,561**	1,624
Offshore Africa		**1,332**	1,407
Other		**40**	81
Oil Sands Mining and Upgrading		**42,016**	41,567
Midstream and Refining		**886**	1,301
Head office		**185**	202
	$	**76,665**	$ 75,276

23. Remuneration of Directors and Senior Management

REMUNERATION OF NON-MANAGEMENT DIRECTORS

		2021	2020	2019
Fees earned	**$**	**2**	$ 2	$ 2

REMUNERATION OF SENIOR MANAGEMENT[1]

		2021	2020	2019
Salary	**$**	**2**	$ 2	$ 2
Common stock option based awards		**10**	9	8
Annual incentive plans		**6**	4	6
Long-term incentive plans		**19**	14	20
	$	**37**	$ 29	$ 36

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



CANADIAN NATURAL RESOURCES LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2021

March 2, 2022

Management's Discussion and Analysis

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Definitions and Abbreviations

AECO	Alberta natural gas reference location
AIF	Annual Information Form
AOSP	Athabasca Oil Sands Project
API	specific gravity measured in degrees on the American Petroleum Institute scale
ARO	asset retirement obligations
bbl	barrel
bbl/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Bitumen	a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons that are too heavy or thick to flow at reservoir conditions, and recoverable at economic rates using thermal in situ recovery methods
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
Brent	Dated Brent
C$	Canadian dollars
CAGR	compound annual growth rate
CAPEX	capital expenditures
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
Crude oil	includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil
CSS	Cyclic Steam Stimulation
EOR	Enhanced Oil Recovery
E&P	Exploration and Production
FASB	Financial Accounting Standards Board
FPSO	Floating Production, Storage and Offloading Vessel
GHG	greenhouse gas
GJ	gigajoules
GJ/d	gigajoules per day
Horizon	Horizon Oil Sands

IASB	International Accounting Standards Board
IBOR	Interbank Offered Rate
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
Mbbl	thousand barrels
Mbbl/d	thousand barrels per day
MBOE	thousand barrels of oil equivalent
MBOE/d	thousand barrels of oil equivalent per day
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
Mcf/d	thousand cubic feet per day
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
NGLs	natural gas liquids
NWRP	North West Redwater Partnership
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OPEC+	Organization of the Petroleum Exporting Countries Plus
PRT	Petroleum Revenue Tax
SAGD	Steam-Assisted Gravity Drainage
SCO	synthetic crude oil
SEC	United States Securities and Exchange Commission
SOFR	Secured Overnight Financing Rate
Tcf	trillion cubic feet
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US GAAP	generally accepted accounting principles in the United States
US$	United States dollars
WCS	Western Canadian Select
WCS Heavy Differential	WCS Heavy Differential from WTI
WTI	West Texas Intermediate reference location at Cushing, Oklahoma

Advisory

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, income tax expenses and other targets provided throughout this Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including, without limitation, those in relation to: the Company's assets at Horizon, AOSP, the Primrose thermal oil projects, the Pelican Lake water and polymer flood projects, the Kirby Thermal Oil Sands Project, the Jackfish Thermal Oil Sands Project and the North West Redwater bitumen upgrader and refinery; construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, NGLs or SCO that the Company may be reliant upon to transport its products to market, the development and deployment of technology and technological innovations; the financial capacity of the Company to complete its growth projects and responsibly and sustainably grow in the long-term; and the "Outlook" section of this MD&A, particularly in reference to the 2022 targets provided with respect to budgeted capital expenditures, and the timing and impact of the Oil Sands Pathways to Net Zero ("Pathways") initiative, government support for Pathways and the ability to achieve net zero emissions from oil production, 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 effects of the novel coronavirus ("COVID-19") pandemic and the actions of OPEC+) which may impact, among other things, demand and supply for and market prices of the Company's products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil and natural gas and NGLs prices including due to actions of OPEC+ taken in response to COVID-19 or otherwise; fluctuations in currency and interest rates; assumptions on which the Company's current targets are based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; 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 any 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 sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short, medium, and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by national, federal, provincial, state and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this MD&A could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by applicable law, the Company assumes no obligation to update forward-looking statements in this MD&A, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company's estimates or opinions change.

SPECIAL NOTE REGARDING NON-GAAP AND OTHER FINANCIAL MEASURES

This MD&A includes references to non-GAAP measures, which include non-GAAP and other financial measures as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure ("NI 52-112"). Non-GAAP measures are used by the Company to evaluate its financial performance, financial position or cash flow. Descriptions of the Company's non-GAAP and other financial measures included in this MD&A, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided in the “Non-GAAP and Other Financial Measures” section of this MD&A.

SPECIAL NOTE REGARDING CURRENCY, FINANCIAL INFORMATION, PRODUCTION AND RESERVES

This MD&A should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2021. It should also be read in conjunction with the Company's MD&A for the three months and year ended December 31, 2021. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's consolidated financial statements and this MD&A have been prepared in accordance with IFRS as issued by the IASB.

Production volumes, per unit statistics and reserves data are presented throughout this MD&A on a "before royalties" or "company gross" basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO. Production on an "after royalties" or "company net" basis is also presented in this MD&A for information purposes only.

The following discussion and analysis refers primarily to the Company's 2021 financial results compared to 2020 and 2019, unless otherwise indicated. In addition, this MD&A details the Company's targeted capital program for 2022. Additional information relating to the Company, including its quarterly MD&A for the three months and year ended December 31, 2021, its Annual Information Form for the year ended December 31, 2021, and its audited consolidated financial statements for the year ended December 31, 2021, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Information on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated March 2, 2022.

Objectives and Strategy

The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value [(1)] on a per common share basis through the economic and sustainable development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves. The Company strives to meet these objectives in a sustainable and responsible way, maintaining a commitment to environmental stewardship and safety excellence.

The Company strives to meet these objectives by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a balanced approach to growth and investments and focuses on creating long-term shareholder value. The Company allocates its capital by maintaining:

- Balance among its products, namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil [(2)], bitumen (thermal oil), SCO and natural gas;
- A large, balanced, diversified, high quality, long life low decline asset base;
- Balance among acquisitions, development and exploration;
- Balance between sources and terms of debt financing and a strong financial position; and
- Commitment to environmental stewardship throughout the decision-making process.

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

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

Operational discipline, safe, effective and efficient operations, and cost control are fundamental to the Company and embrace the key piece of the Company's mission statement: "doing it right". By consistently managing costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Effective and efficient operations and cost control are attained by developing area knowledge, and by maintaining high working interests and operator status in the Company's properties.

The Company is committed to maintaining a strong balance sheet and flexible capital structure. The Company believes it has built the necessary financial capacity to complete its growth projects. Additionally, the Company periodically utilizes its risk management hedging program to reduce the risk of volatility in commodity prices and foreign exchange rates and to support the Company's cash flow for its capital expenditure programs.

Strategic accretive acquisitions are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt and equity financing to selectively acquire properties generating future cash flows in its core areas. The Company's financial discipline, commitment to a strong balance sheet, and capacity to internally generate cash flows provides the means to responsibly and sustainably grow in the long term.

(1) Discounted value of crude oil and natural gas reserves plus value of unproved land, less net debt.

(2) Pelican Lake heavy crude oil is 12–17º API oil, which receives medium quality crude netbacks due to lower production expense and lower royalty rates.

Financial and Operational Highlights

($ millions, except per common share amounts)			2021		2020		2019
Product sales [1]		$	**32,854**	$	17,491	$	24,394
Crude oil and NGLs		$	**29,256**	$	15,579	$	22,950
Natural gas		$	**2,716**	$	1,478	$	1,419
Net earnings (loss)		$	**7,664**	$	(435)	$	5,416
Per common share	– basic	$	**6.49**	$	(0.37)	$	4.55
	– diluted	$	**6.46**	$	(0.37)	$	4.54
Adjusted net earnings (loss) from operations [2]		$	**7,420**	$	(756)	$	3,795
Per common share	– basic [3]	$	**6.28**	$	(0.64)	$	3.19
	– diluted [3]	$	**6.25**	$	(0.64)	$	3.18
Cash flows from operating activities		$	**14,478**	$	4,714	$	8,829
Adjusted funds flow [2]		$	**13,733**	$	5,200	$	10,267
Per common share	– basic [3]	$	**11.63**	$	4.40	$	8.62
	– diluted [3]	$	**11.57**	$	4.40	$	8.61
Dividends declared per common share [4]		$	**2.00**	$	1.70	$	1.50
Total assets		$	**76,665**	$	75,276	$	78,121
Total long-term liabilities		$	**32,298**	$	37,818	$	36,493
Cash flows used in investing activities		$	**3,703**	$	2,819	$	7,255
Net capital expenditures [2]		$	**4,908**	$	3,206	$	7,121
Average realized price							
Crude oil and NGLs - Exploration and Production ($/bbl) [3]		$	**63.71**	$	31.90	$	55.08
Natural gas - Exploration and Production ($/Mcf) [5]		$	**4.07**	$	2.40	$	2.34
SCO - Oil Sands Mining and Upgrading ($/bbl) [3]		$	**77.95**	$	43.98	$	70.18
Daily production, before royalties (BOE/d)			**1,234,906**		1,164,136		1,098,957
Crude oil and NGLs (bbl/d)			**952,404**		917,958		850,393
Natural gas (MMcf/d) [6]			**1,695**		1,477		1,491

(1) Further details related to product sales are disclosed in note 22 to the Company's audited consolidated financial statements.

(2) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(3) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(4) On November 3, 2021, the Board of Directors approved a 25% increase in the quarterly dividend to $0.5875 per common share, from $0.47 per common share. On March 3, 2021, the Board of Directors approved an 11% increase in the quarterly dividend to $0.47 per common share, from $0.425 per common share. On March 4, 2020, the Board of Directors approved a 13% increase in the quarterly dividend to $0.425 per common share, from $0.375 per common share. On March 6, 2019, the Board of Directors approved a 12% increase in the quarterly dividend to $0.375 per common share, from $0.335 per common share. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

(5) Calculated as natural gas sales divided by sales volumes.

(6) Natural gas production volumes approximate sales volumes.

CONSOLIDATED NET EARNINGS (LOSS) AND ADJUSTED NET EARNINGS (LOSS)

For 2021, the Company reported net earnings of $7,664 million compared with a net loss of $435 million for 2020 (2019 – net earnings of $5,416 million). Net earnings for 2021 included non-operating items (after-tax) of $244 million compared with $321 million for 2020 (2019 – $1,621 million) related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of a realized foreign exchange loss on repayment of US dollar debt securities, the realized foreign exchange gain on the settlement of the cross currency swaps, the gain on acquisitions, the (gain) loss from investments, government grant income under the provincial well-site rehabilitation programs, and a provision relating to the Keystone XL pipeline project. Excluding these items, adjusted net earnings from operations for 2021 were $7,420 million compared with an adjusted net loss from operations of $756 million for 2020 (2019 – adjusted net earnings from operations of $3,795 million).

The net earnings and the adjusted net earnings from operations for 2021 compared with a net loss and adjusted net loss from operations for 2020 primarily reflected:

- higher realized SCO sales price [(1)] in the Oil Sands Mining and Upgrading segment;
- higher crude oil and NGLs netbacks [(1)] and natural gas netbacks [(1)] in the Exploration and Production segments;
- higher natural gas sales volumes in the North America segment;
- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment; and
- lower depletion, depreciation and amortization expense.

A detailed reconciliation of the changes in the Company's product sales is provided in the "Analysis of Changes in Product Sales" section of this MD&A.

The impacts of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the gain on acquisitions, income from NWRP, and the (gain) loss from investments, also contributed to the movements in net earnings (loss) for 2021 from 2020. These items are discussed in detail in the relevant sections of this MD&A.

CASH FLOWS FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW

Cash flows from operating activities for 2021 were $14,478 million compared with $4,714 million for 2020 (2019 – $8,829 million). The increase in cash flows from operating activities for 2021 from 2020 were primarily due to the factors previously noted related to the fluctuations in net earnings (loss) from operations, as well as due to the impact of changes in non-cash working capital, and excluding the impact of changes in depletion, depreciation and amortization expense.

Adjusted funds flow for 2021 was $13,733 million ($11.63 per common share) compared with $5,200 million for 2020 ($4.40 per common share) (2019 – $10,267 million; $8.62 per common share). The increase in adjusted funds flow for 2021 from 2020 was primarily due to the factors noted above related to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment expenditures excluding the impact of government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets, including the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to NWRP, and prepaid cost of service tolls.

PRODUCTION VOLUMES

Crude oil and NGLs production before royalties for 2021 increased 4% to average 952,404 bbl/d from 917,958 bbl/d in 2020 (2019 – 850,393 bbl/d). Natural gas production before royalties for 2021 increased 15% to average 1,695 MMcf/d from 1,477 MMcf/d in 2020 (2019 – 1,491 MMcf/d). Total production before royalties for 2021 of 1,234,906 BOE/d increased 6% from 1,164,136 BOE/d in 2020 (2019 – 1,098,957 BOE/d). Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

(1) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

PRODUCT PRICES

In the Company's Exploration and Production segments, the 2021 realized crude oil and NGLs prices [(1)] increased 100% to average $63.71 per bbl from $31.90 per bbl in 2020 (2019 – $55.08 per bbl), and the 2021 realized natural gas price [(1)] increased 70% to average $4.07 per Mcf from $2.40 per Mcf in 2020 (2019 – $2.34 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2021 realized SCO sales price increased 77% to average $77.95 per bbl from $43.98 per bbl in 2020 (2019 – $70.18 per bbl). Crude oil and NGLs and natural gas prices are discussed in detail in the "Business Environment", "Realized Product Prices - Exploration and Production", and the "Oil Sands Mining and Upgrading" sections of this MD&A.

PRODUCTION EXPENSE

In the Company's Exploration and Production segments, the 2021 crude oil and NGLs production expense [(2)] increased 18% to average $14.71 per bbl from $12.42 per bbl in 2020 (2019 – $13.81 per bbl), and the natural gas production expense [(2)] averaged $1.18 per Mcf in 2021 and 2020 (2019 – $1.22 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2021 production cost [(2)] averaged $20.91 per bbl and was comparable with $20.46 per bbl in 2020 (2019 – $22.56 per bbl). Crude oil and NGLs and natural gas production expense is discussed in detail in the "Exploration and Production" and the "Oil Sands Mining and Upgrading" sections of this MD&A.

SUMMARY OF QUARTERLY FINANCIAL RESULTS

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

($ millions, except per common share amounts)

2021	**Total**	**Dec 31**	**Sep 30**	**Jun 30**	**Mar 31**
Product sales [(1)]	**$ 32,854**	**$ 10,190**	**$ 8,521**	**$ 7,124**	**$ 7,019**
Crude oil and NGLs	**$ 29,256**	**$ 8,979**	**$ 7,607**	**$ 6,382**	**$ 6,288**
Natural gas	**$ 2,716**	**$ 958**	**$ 694**	**$ 509**	**$ 555**
Net earnings (loss)	**$ 7,664**	**$ 2,534**	**$ 2,202**	**$ 1,551**	**$ 1,377**
Net earnings (loss) per common share					
– basic	**$ 6.49**	**$ 2.16**	**$ 1.87**	**$ 1.31**	**$ 1.16**
– diluted	**$ 6.46**	**$ 2.14**	**$ 1.86**	**$ 1.30**	**$ 1.16**

($ millions, except per common share amounts)

2020	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales [(1)]	$ 17,491	$ 5,219	$ 4,676	$ 2,944	$ 4,652
Crude oil and NGLs	$ 15,579	$ 4,592	$ 4,202	$ 2,462	$ 4,323
Natural gas	$ 1,478	$ 496	$ 338	$ 307	$ 337
Net earnings (loss)	$ (435)	$ 749	$ 408	$ (310)	$ (1,282)
Net earnings (loss) per common share					
– basic	$ (0.37)	$ 0.63	$ 0.35	$ (0.26)	$ (1.08)
– diluted	$ (0.37)	$ 0.63	$ 0.35	$ (0.26)	$ (1.08)

(1) Further details related to product sales are disclosed in note 22 to the Company's audited consolidated financial statements.

(1) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(2) Calculated as respective production expense divided by respective sales volumes.

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

- **Crude oil pricing –** Fluctuating global supply/demand including crude oil production levels from OPEC+ and its impact on world supply; the impact of geopolitical and market uncertainties, including those due to COVID-19 and in connection with governmental responses to COVID-19, on worldwide benchmark pricing; the impact of shale oil production in North America; the impact of the WCS Heavy Differential from WTI in North America; the impact of the differential between WTI and Brent benchmark pricing in the North Sea and Offshore Africa; and the impact of production curtailments mandated by the Government of Alberta that came into effect on January 1, 2019 and were suspended effective December 1, 2020.
- **Natural gas pricing –** The impact of fluctuations in both the demand for natural gas and inventory storage levels, third-party pipeline maintenance and outages, and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes –** Fluctuations in production from the Kirby and Jackfish Thermal Oil Sands Projects, fluctuations in production due to the cyclic nature of the Primrose thermal oil projects, fluctuations in the Company's drilling program in North America and the International segments, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, production curtailments mandated by the Government of Alberta that came into effect January 1, 2019 and were suspended effective December 1, 2020, and the impact of shut-in production due to lower demand during COVID-19. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes –** Fluctuations in production due to the Company's allocation of capital to high return projects, drilling results, natural decline rates, the temporary shut-down and subsequent reinstatement of the Pine River Gas Plant, and the impact and timing of acquisitions.
- **Production expense –** Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production volumes, the impact of seasonality, the impact of increased carbon tax and energy costs, cost optimizations across all segments, the impact and timing of acquisitions, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.
- **Transportation, blending and feedstock expense –** Fluctuations due to the provision recognized relating to the cancellation of the Keystone XL pipeline project in 2020.
- **Depletion, depreciation and amortization expense –** Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, and the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment.
- **Share-based compensation –** Fluctuations due to the measurement of fair market value of the Company's share-based compensation liability.
- **Risk management –** Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Interest expense –** Fluctuations due to changing long-term debt levels, and the impact of movements in benchmark interest rates on outstanding floating rate long-term debt.
- **Foreign exchange –** Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company receives for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses were also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Gain on acquisitions, (gain) loss from investments and income from NWRP –** Fluctuations due to the recognition of gains on acquisitions, (gain) loss from the investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("IPL") shares, and the distribution from NWRP in 2021.
- **Income taxes –** Fluctuations due to statutory tax rate and other legislative changes substantively enacted in the various periods.

Business Environment

Global benchmark crude oil prices increased significantly throughout 2021, partially in response to the OPEC+ decision to adhere to previously agreed upon production cut agreements. Additionally, global demand for crude oil increased due to improved economic conditions, as the effects of COVID-19 became less impactful to the global economy. Improved economic conditions continue to positively impact the outlook for crude oil prices, although market conditions remain uncertain.

During 2021, the Company continued to utilize federal and provincial government programs to support employment during the COVID-19 pandemic, including in Canada, the provincial well-site rehabilitation program.

Liquidity

As at December 31, 2021, the Company had undrawn bank credit facilities of $6,098 million. Including cash and cash equivalents and short-term investments, the Company had approximately $7,151 million in liquidity (1). The Company also has certain other dedicated credit facilities supporting letters of credit.

The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure . Refer to the "Liquidity and Capital Resources" section of this MD&A for further details.

Capital Spending

Safe, reliable, effective and efficient operations continue to be a focus for the Company. On January 11, 2022, the Company announced its 2022 base capital budget (2) targeted at approximately $3,645 million. The budget also includes incremental strategic growth capital of approximately $700 million that targets to add future production and capacity in the Company's long life low decline thermal in situ and Oil Sands Mining and Upgrading assets. Production for 2022 is targeted between 1,270,000 BOE/d and 1,320,000 BOE/d. Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, in the context of price volatility, project returns and the balancing of project risks and time horizons. The 2022 capital budget and production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

On December 9, 2020, the Company announced its 2021 capital budget targeted at approximately $3,205 million, and on August 5, 2021, the 2021 capital budget was increased to approximately $3,480 million, excluding acquisitions. Net capital expenditures for 2021 were $4,908 million, including the impact of acquisitions. Refer to the “Net Capital Expenditures” section of this MD&A for further details on the 2021 net capital expenditures.

During 2021, the Company completed the acquisition of all the issued and outstanding common shares of Storm Resources Limited ("Storm") for total cash consideration of approximately $771 million. At closing, the acquisition also included the assumption of long-term debt of approximately $183 million. Storm is involved in the exploration for and development of natural gas and natural gas liquids in the Montney region of British Columbia.

During 2021, the Company also completed a number of other opportunistic acquisitions. Two acquisitions consisted of natural gas assets located in the Montney region of British Columbia, with aggregate production of approximately 11,100 BOE/d. A third acquisition consisted of a net carried interest on an existing oil sands lease held by the Company, from which all Horizon production volumes are derived. Total cash consideration paid for these acquisitions was approximately $450 million.

During 2021, in accordance with a third-party offer to purchase, the Company elected to take total cash proceeds of $128 million, or $20.00 per common share, in exchange for its 6.4 million common share investment in IPL.

Risks and Uncertainties

COVID-19, including variants of concern, continues to have the potential to further 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 their extent and severity.

(1) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(2) Forward looking non-GAAP Financial Measure. The capital budget is based on net capital expenditures (Non-GAAP Financial Measure) and excludes net acquisition costs. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A for more details on Net Capital Expenditures.

BENCHMARK COMMODITY PRICES

(Yearly average)		2021		2020		2019
WTI benchmark price (US$/bbl)	**$**	**67.96**	$	39.40	$	57.04
Dated Brent benchmark price (US$/bbl)	**$**	**70.49**	$	42.27	$	64.04
WCS Heavy Differential from WTI (US$/bbl)	**$**	**13.04**	$	12.57	$	12.79
SCO price (US$/bbl)	**$**	**66.36**	$	36.26	$	56.35
Condensate benchmark price (US$/bbl)	**$**	**68.24**	$	36.97	$	52.84
Condensate Differential from WTI (US$/bbl)	**$**	**(0.28)**	$	2.43	$	4.20
NYMEX benchmark price (US$/MMBtu)	**$**	**3.85**	$	2.08	$	2.63
AECO benchmark price (C$/GJ)	**$**	**3.38**	$	2.12	$	1.54
US/Canadian dollar average exchange rate (US$)	**$**	**0.7979**	$	0.7454	$	0.7536
US/Canadian dollar year end exchange rate (US$)	**$**	**0.7901**	$	0.7840	$	0.7713

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are directly impacted by fluctuations in foreign exchange rates. Product revenue continued to be impacted by the volatility of the Canadian dollar as the Canadian dollar sales price the Company received for its crude oil and natural gas sales is based on US dollar denominated benchmarks.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$67.96 per bbl for 2021, an increase of 72% from US$39.40 per bbl for 2020 (2019 – US$57.04 per bbl).

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$70.49 per bbl for 2021, an increase of 67% from US$42.27 per bbl for 2020 (2019 – US$64.04 per bbl).

The increase in WTI and Brent pricing for 2021 from 2020 primarily reflected the OPEC+ decision to adhere to the previously agreed upon production cut agreements. Additionally, global demand for crude oil increased due to improved economic conditions as a result of the lessening of earlier COVID-19 restrictions.

The WCS Heavy Differential averaged US$13.04 per bbl for 2021, a slight widening of 4% from US$12.57 per bbl for 2020 (2019 – US$12.79 per bbl). The widening of the WCS Heavy Differential for 2021 from 2020 primarily reflected the increase in WTI benchmark pricing and the widening of the US Gulf Coast heavy oil pricing.

The SCO price averaged US$66.36 per bbl for 2021, an increase of 83% from US$36.26 per bbl for 2020 (2019 – US$56.35 per bbl). The increase in SCO pricing for 2021 from 2020 primarily reflected the increase in WTI benchmark pricing.

NYMEX natural gas prices averaged US$3.85 per MMBtu for 2021, an increase of 85% from US$2.08 per MMBtu for 2020 (2019 – US$2.63 per MMBtu). The increase in NYMEX natural gas prices for 2021 from 2020 primarily reflected increased North American demand in 2021, following the impact of COVID-19 in 2020, as well as lower storage levels.

AECO natural gas prices averaged $3.38 per GJ for 2021, an increase of 59% from $2.12 per GJ for 2020 (2019 – $1.54 per GJ). The increase in AECO natural gas prices for 2021 from 2020 primarily reflected lower storage levels and increased NYMEX benchmark pricing.

Analysis of Changes in Product Sales

($ millions)	2019	Changes due to Volumes	Changes due to Prices	Changes due to Other	2020	**Changes due to Volumes**	**Changes due to Prices**	**Changes due to Other**	**2021**
North America									
Crude oil and NGLs	$ 9,679	$ 1,582	$ (3,781)	$ —	$ 7,480	**$ 82**	**$ 6,916**	**$ —**	**$ 14,478**
Natural gas	1,150	8	84	—	1,242	**193**	**1,049**	**—**	**2,484**
Other [1]	6	—	—	35	41	**—**	**—**	**78**	**119**
	10,835	1,590	(3,697)	35	8,763	**275**	**7,965**	**78**	**17,081**
North Sea									
Crude oil and NGLs	860	(135)	(308)	—	417	**(72)**	**262**	**—**	**607**
Natural gas	57	(29)	(16)	—	12	**(8)**	**1**	**—**	**5**
Other [1]	5	—	—	(2)	3	**—**	**—**	**(4)**	**(1)**
	922	(164)	(324)	(2)	432	**(80)**	**263**	**(4)**	**611**
Offshore Africa									
Crude oil and NGLs	632	(116)	(198)	—	318	**(68)**	**170**	**—**	**420**
Natural gas	67	(27)	2	—	42	**(9)**	**(2)**	**—**	**31**
Other [1]	8	—	—	10	18	**—**	**—**	**(11)**	**7**
	707	(143)	(196)	10	378	**(77)**	**168**	**(11)**	**458**
Oil Sands Mining and Upgrading									
Crude oil and NGLs	11,340	470	(4,421)	—	7,389	**560**	**6,084**	**—**	**14,033**
Other [1]	6	—	—	133	139	**—**	**—**	**(66)**	**73**
	11,346	470	(4,421)	133	7,528	**560**	**6,084**	**(66)**	**14,106**
Midstream and Refining									
Midstream activities	88	—	—	(5)	83	**—**	**—**	**(5)**	**78**
Refined product sales and other [1]	—	—	—	202	202	**—**	**—**	**479**	**681**
	88	—	—	197	285	**—**	**—**	**474**	**759**
Intersegment eliminations and other [2]									
Product sales	496	—	—	(422)	74	**—**	**—**	**(238)**	**(164)**
Other [1]	—	—	—	31	31	**—**	**—**	**(28)**	**3**
	496	—	—	(391)	105	**—**	**—**	**(266)**	**(161)**
Total	$ 24,394	$ 1,753	$ (8,638)	$ (18)	$ 17,491	**$ 678**	**$ 14,480**	**$ 205**	**$ 32,854**

(1) Includes the sale of diesel and other refined products and other income, including government grants and recoveries associated with the joint operations partners' share of the costs of lease contracts.

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

Product sales increased 88% to $32,854 million for 2021 from $17,491 million for 2020 (2019 – $24,394 million). The increase in product sales was primarily a result of increased WTI benchmark pricing due to increased demand for refined products as a result of improved economic conditions. Crude oil and NGLs and natural gas pricing are discussed in detail in the "Business Environment", "Exploration and Production" and the "Oil Sands Mining and Upgrading" sections of this MD&A. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

For 2021, 3% of the Company's crude oil and NGLs and natural gas product sales were generated outside of North America (2020 – 5%; 2019 – 7%). North Sea accounted for 2% of crude oil and NGLs and natural gas product sales for 2021 (2020 – 3%; 2019 – 4%), and Offshore Africa accounted for 1% of crude oil and NGLs and natural gas product sales for 2021 (2020 – 2%; 2019 – 3%).

Daily Production

DAILY PRODUCTION, BEFORE ROYALTIES

	2021	2020	2019
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**472,621**	460,443	405,970
North America – Oil Sands Mining and Upgrading [1]	**448,133**	417,351	395,133
North Sea	**17,633**	23,142	27,919
Offshore Africa	**14,017**	17,022	21,371
	952,404	917,958	850,393
Natural gas (MMcf/d) [2]			
North America	**1,680**	1,450	1,443
North Sea	**3**	12	24
Offshore Africa	**12**	15	24
	1,695	1,477	1,491
Total barrels of oil equivalent (BOE/d)	**1,234,906**	1,164,136	1,098,957
Product mix			
Light and medium crude oil and NGLs	**10%**	11%	13%
Pelican Lake heavy crude oil	**5%**	5%	5%
Primary heavy crude oil	**5%**	6%	8%
Bitumen (thermal oil)	**21%**	21%	15%
Synthetic crude oil [1]	**36%**	36%	36%
Natural gas	**23%**	21%	23%
Percentage of gross revenue [1] [3] (excluding Midstream and Refining revenue)			
Crude oil and NGLs	**91%**	91%	94%
Natural gas	**9%**	9%	6%

(1) SCO production before royalties excludes SCO consumed internally as diesel.

(2) Natural gas production volumes approximate sales volumes.

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

DAILY PRODUCTION, NET OF ROYALTIES

	2021	2020	2019
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**404,637**	420,906	356,794
North America – Oil Sands Mining and Upgrading	**410,385**	413,363	375,048
North Sea	**17,588**	23,086	27,866
Offshore Africa	**13,354**	16,306	20,078
	845,964	873,661	779,786
Natural gas (MMcf/d)			
North America	**1,593**	1,406	1,400
North Sea	**3**	12	24
Offshore Africa	**11**	14	22
	1,607	1,432	1,446
Total barrels of oil equivalent (BOE/d)	**1,113,878**	1,112,364	1,020,749

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

Total 2021 production before royalties averaged 1,234,906 BOE/d, an increase of 6% from 1,164,136 BOE/d in 2020 (2019 – 1,098,957 BOE/d).

Record crude oil and NGLs production before royalties for 2021 averaged 952,404 bbl/d, an increase of 4% from 917,958 bbl/d for 2020 (2019 – 850,393 bbl/d). The increase in crude oil and NGLs production for 2021 from 2020 primarily reflected strong operational performance in the Oil Sands Mining and Upgrading segment and increased thermal oil production. Crude oil and NGLs production in North America Exploration and Production and Oil Sands Mining and Upgrading segments for the comparable periods of 2020 reflected the impact of the Company's curtailment optimization strategy during mandatory Government of Alberta curtailment.

Annual crude oil and NGLs production for 2021 was within the Company's previously issued target of 940,000 bbl/d and 980,000 bbl/s. The Company targets production levels in 2022 to average between 940,000 bbl/d and 982,000 bbl/d of liquids production, including crude oil, SCO and NGLs. Production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Natural gas production before royalties accounted for 23% of the Company's total production in 2021 on a BOE basis. Natural gas production for 2021 of 1,695 MMcf/d increased 15% from 1,477 MMcf/d for 2020 (2019 – 1,491 MMcf/d). The increase in natural gas production for 2021 from 2020 primarily reflected strong drilling results and production volumes from acquisitions, partially offset by natural field declines.

Annual natural gas production for 2021 was within the Company's previously issued target of 1,680 MMcf/d and 1,720 MMcf/d. The Company targets production levels in 2022 to average between 1,980 MMcf/d and 2,030 MMcf/d of natural gas production. Production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for 2021 averaged 472,621 bbl/d, an increase of 3% from 460,443 bbl/d for 2020 (2019 – 405,970 bbl/d). The increase in crude oil and NGLs production for 2021 from 2020 primarily reflected increased thermal oil production and strong drilling results, partially offset by natural field declines.

Thermal oil production before royalties for 2021 averaged 259,284 bbl/d, an increase of 4% from 248,971 bbl/d for 2020 (2019 – 167,942 bbl/d). The increase in thermal oil production for 2021 from 2020 primarily reflected high utilization at Jackfish.

Pelican Lake heavy crude oil production before royalties averaged 54,390 bbl/d for 2021, a decrease of 4% from 56,535 bbl/d for 2020 (2019 – 58,855 bbl/d), demonstrating Pelican Lake's long life low decline production.

Natural gas production before royalties for 2021 averaged 1,680 MMcf/d, an increase of 16% from 1,450 MMcf/d for 2020 (2019 – 1,443 MMcf/d). The increase in natural gas production for 2021 from 2020 primarily reflected strong drilling results and production volumes from acquisitions, partially offset by natural field declines.

North America – Oil Sands Mining and Upgrading

Record SCO production before royalties for 2021 of 448,133 bbl/d increased 7% from 417,351 bbl/d for 2020 (2019 – 395,133 bbl/d). The increase in SCO production for 2021 from 2020 primarily reflected strong operational performance at AOSP following the completion of expansion activities at Scotford in 2020.

North Sea

North Sea crude oil production before royalties for 2021 of 17,633 bbl/d decreased 24% from 23,142 bbl/d for 2020 (2019 – 27,919 bbl/d). The decrease in production for 2021 from 2020 primarily reflected natural field declines and planned maintenance activities.

Offshore Africa

Offshore Africa crude oil production before royalties for 2021 decreased 18% to 14,017 bbl/d from 17,022 bbl/d for 2020 (2019 – 21,371 bbl/d). The decrease in production for 2021 from 2020 primarily reflected maintenance activities and natural field declines.

INTERNATIONAL CRUDE OIL INVENTORY VOLUMES

The Company recognizes revenue on its crude oil production when control of the product passes to the customer and delivery has taken place. Revenue has not been recognized in the International segments on crude oil volumes held in various storage facilities or FPSOs, as follows:

(bbl)	**2021**	2020	2019
North Sea	**—**	450,889	344,726
Offshore Africa	**727,439**	521,244	519,504
	727,439	972,133	864,230

Exploration and Production

OPERATING HIGHLIGHTS

		2021		2020		2019
Crude oil and NGLs ($/bbl) [1]						
Realized price [2]	**$**	**63.71**	$	31.90	$	55.08
Transportation [2]		**3.86**		3.85		3.48
Realized price, net of transportation [2]		**59.85**		28.05		51.60
Royalties [3]		**8.59**		2.59		6.08
Production expense [4]		**14.71**		12.42		13.81
Netback [2]	**$**	**36.55**	$	13.04	$	31.71
Natural gas ($/Mcf) [1]						
Realized price [5]	**$**	**4.07**	$	2.40	$	2.34
Transportation [6]		**0.45**		0.43		0.42
Realized price, net of transportation		**3.62**		1.97		1.92
Royalties [3]		**0.22**		0.08		0.08
Production expense [4]		**1.18**		1.18		1.22
Netback [2]	**$**	**2.22**	$	0.71	$	0.62
Barrels of oil equivalent ($/BOE) [1]						
Realized price [2]	**$**	**49.67**	$	26.15	$	40.50
Transportation [2]		**3.44**		3.44		3.14
Realized price, net of transportation [2]		**46.23**		22.71		37.36
Royalties [3]		**5.98**		1.89		4.09
Production expense [4]		**11.98**		10.67		11.49
Netback [2]	**$**	**28.27**	$	10.15	$	21.78

(1) For crude oil and NGLs and BOE sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A. For natural gas sales volumes, refer to the "Daily Production, before royalties" section of this MD&A.

(2) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(3) Calculated as royalties divided by respective sales volumes.

(4) Calculated as production expense divided by respective sales volumes.

(5) Calculated as natural gas sales divided by natural gas sales volumes.

(6) Calculated as natural gas transportation expense divided by natural gas sales volumes.

REALIZED PRODUCT PRICES – EXPLORATION AND PRODUCTION

		2021		2020		2019
Crude oil and NGLs ($/bbl) [1]						
North America [2]	**$**	**62.10**	$	30.31	$	51.43
North Sea [3]	**$**	**87.98**	$	50.09	$	86.76
Offshore Africa [3]	**$**	**85.71**	$	50.95	$	83.68
Average [2]	**$**	**63.71**	$	31.90	$	55.08
Natural gas ($/Mcf) [1] [3]						
North America	**$**	**4.05**	$	2.34	$	2.18
North Sea	**$**	**2.94**	$	2.74	$	6.52
Offshore Africa	**$**	**7.17**	$	7.77	$	7.41
Average	**$**	**4.07**	$	2.40	$	2.34
Average ($/BOE) [1] [2]	**$**	**49.67**	$	26.15	$	40.50

(1) For crude oil and NGLs and BOE sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A. For natural gas sales volumes, refer to the "Daily Production, before royalties" section of this MD&A.

(2) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(3) Calculated as crude oil and NGLs sales and natural gas sales divided by respective sales volumes.

North America

North America realized crude oil and NGLs prices increased by $31.79 per bbl to average $62.10 per bbl for 2021 from $30.31 per bbl for 2020 (2019 – $51.43 per bbl), primarily due to higher WTI benchmark pricing.

The Company continues to focus on its crude oil blending marketing strategy including a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil and bitumen (thermal oil) conversion capacity. During 2021, the Company contributed approximately 152,000 bbl/d of heavy crude oil blends to the WCS stream.

The Company has 20-year transportation agreements to ship 94,000 bbl/d of crude oil on the proposed Trans Mountain Pipeline Expansion that will provide waterborne access to international markets. The expansion is now under construction and Trans Mountain Corporation targets a completion date of late 2023.

North America realized natural gas prices increased 73% to average $4.05 per Mcf for 2021 from $2.34 per Mcf for 2020 (2019 – $2.18 per Mcf). The increase in realized natural gas prices for 2021 from 2020 primarily reflected lower storage levels and increased benchmark pricing.

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

(Yearly average)		2021		2020		2019
Wellhead Price [1]						
Light and medium crude oil and NGLs ($/bbl)	**$**	**61.29**	$	33.42	$	49.54
Pelican Lake heavy crude oil ($/bbl)	**$**	**68.05**	$	33.57	$	57.82
Primary heavy crude oil ($/bbl)	**$**	**65.88**	$	31.81	$	55.38
Bitumen (thermal oil) ($/bbl)	**$**	**60.20**	$	28.11	$	48.27
Natural gas ($/Mcf)	**$**	**4.05**	$	2.34	$	2.18

(1) Amounts expressed on a per unit basis are based on sales volumes of the respective product type.

North Sea

North Sea realized crude oil and NGLs prices increased 76% to average $87.98 per bbl for 2021 from $50.09 per bbl for 2020 (2019 – $86.76 per bbl). Realized crude oil and NGLs prices per barrel in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The increase in realized crude oil and NGLs prices for 2021 from 2020 reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil and NGLs prices increased 68% to average $85.71 per bbl for 2021 from $50.95 per bbl for 2020 (2019 – $83.68 per bbl). Realized crude oil and NGLs prices per barrel in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The increase in realized crude oil and NGLs prices in 2021 reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

		2021		2020		2019
Crude oil and NGLs ($/bbl) [(1)]						
North America	**$**	**9.06**	$	2.72	$	6.56
North Sea	**$**	**0.19**	$	0.12	$	0.16
Offshore Africa	**$**	**3.94**	$	2.17	$	4.74
Average	**$**	**8.59**	$	2.59	$	6.08
Natural gas ($/Mcf) [(1)]						
North America	**$**	**0.22**	$	0.07	$	0.07
Offshore Africa	**$**	**0.33**	$	0.37	$	0.63
Average	**$**	**0.22**	$	0.08	$	0.08
Average ($/BOE) [(1)]	**$**	**5.98**	$	1.89	$	4.09

(1) Calculated as royalties divided by respective sales volumes. For crude oil and NGLs and BOE sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A. For natural gas sales volumes, refer to the "Daily Production, before royalties" section of this MD&A.

North America

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

North America crude oil and NGLs and natural gas royalties for 2021 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential and changes in the production mix between high and low royalty rate product types.

Crude oil and NGLs royalty rates [(1)] averaged approximately 15% of product sales for 2021 compared with 9% of product sales for 2020 (2019 – 13%). The increase in royalty rates for 2021 from 2020 was primarily due to higher benchmark prices together with fluctuations in the WCS Heavy Differential.

Natural gas royalty rates averaged approximately 5% of product sales for 2021, compared with 3% of product sales for 2020 (2019 – 3%). The increase in royalty rates for 2021 from 2020 was primarily due to higher benchmark prices.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 5% for 2021 compared with 4% of product sales for 2020 (2019 – 6%). Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

(1) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

		2021		2020		2019
Crude oil and NGLs ($/bbl) [1]						
North America	**$**	**13.12**	$	11.21	$	12.41
North Sea	**$**	**54.13**	$	36.51	$	36.39
Offshore Africa	**$**	**14.73**	$	13.29	$	11.21
Average	**$**	**14.71**	$	12.42	$	13.81
Natural gas ($/Mcf) [1]						
North America	**$**	**1.15**	$	1.14	$	1.16
North Sea	**$**	**7.31**	$	3.72	$	3.40
Offshore Africa	**$**	**4.41**	$	3.58	$	2.60
Average	**$**	**1.18**	$	1.18	$	1.22
Average ($/BOE) [1]	**$**	**11.98**	$	10.67	$	11.49

(1) Calculated as production expense divided by respective sales volumes. For crude oil and NGLs and BOE sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A. For natural gas sales volumes, refer to the "Daily Production, before royalties" section of this MD&A.

North America

North America crude oil and NGLs production expense for 2021 averaged $13.12 per bbl, an increase of 17% from $11.21 per bbl for 2020 (2019 – $12.41 per bbl). The increase in crude oil and NGLs production expense per bbl for 2021 from 2020 reflected increased energy costs.

North America natural gas production expense for 2021 averaged $1.15 per Mcf, comparable with $1.14 per Mcf for 2020 (2019 – $1.16 per Mcf). Natural gas production expense per Mcf for 2021 primarily reflected higher production volumes and the Company's strong focus on cost control.

North Sea

North Sea crude oil production expense for 2021 averaged $54.13 per bbl, an increase of 48% from $36.51 per bbl for 2020 (2019 – $36.39 per bbl). The increase in crude oil production expense per bbl for 2021 from 2020 primarily reflected lower volumes on a relatively fixed cost base, as well as higher natural gas and CO_2 costs. North Sea production expense also reflected fluctuations in the Canadian dollar.

Offshore Africa

Offshore Africa crude oil production expense for 2021 averaged $14.73 per bbl, an increase of 11% from $13.29 per bbl for 2020 (2019 – $11.21 per bbl). The increase in crude oil production expense per bbl for 2021 from 2020 primarily reflected timing of liftings from various fields that have different cost structures, together with lower volumes, on a relatively fixed cost base. Offshore Africa production expense also reflected fluctuations in the Canadian dollar.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)		2021		2020		2019
North America	**$**	**3,569**	$	3,780	$	3,326
North Sea		**160**		277		308
Offshore Africa		**142**		190		242
Depletion, depreciation and amortization	**$**	**3,871**	$	4,247	$	3,876
$/BOE [1]	**$**	**13.49**	$	15.45	$	15.22

(1) Calculated as depletion, depreciation and amortization expense divided by sales volumes. For sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

Depletion, depreciation and amortization expense for 2021 of $13.49 per BOE decreased 13% from $15.45 per BOE for 2020 (2019 – $15.22 per BOE). The decrease in depletion, depreciation and amortization expense per BOE for 2021 from 2020 primarily reflected lower depletion rates in the North America Exploration and Production segment and lower volumes in the North Sea, which has higher depletion rates.

Depletion, depreciation and amortization expense on an absolute and per BOE basis also reflects the impact of the timing of liftings from each field in the North Sea and Offshore Africa.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)		**2021**		2020		2019
North America	**$**	**101**	$	97	$	95
North Sea		**21**		30		28
Offshore Africa		**6**		6		6
Asset retirement obligation accretion	**$**	**128**	$	133	$	129
$/BOE [1]	**$**	**0.44**	$	0.48	$	0.51

(1) Calculated as asset retirement obligation accretion divided by sales volumes. For sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

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

Asset retirement obligation accretion expense for 2021 of $0.44 per BOE decreased 8% from $0.48 per BOE for 2020 (2019 – $0.51 per BOE). Fluctuations in asset retirement obligation accretion expense on a per BOE basis primarily reflect fluctuating sales volumes.

Oil Sands Mining and Upgrading

OPERATING HIGHLIGHTS

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the Horizon and AOSP sites. Record SCO production in 2021 averaged 448,133 bbl/d, primarily reflecting strong operational performance.

The Company incurred production costs, excluding natural gas costs, of $3,176 million ($19.45 per bbl) for 2021, a 7% increase (comparable on a per bbl basis) from $2,968 million ($19.50 per bbl) for 2020, reflecting higher energy costs, offset by record production volumes, together with the Company's strong focus on cost control.

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

($/bbl)		**2021**		2020		2019
Realized SCO sales price [1]	**$**	**77.95**	$	43.98	$	70.18
Bitumen value for royalty purposes [2]	**$**	**58.39**	$	25.82	$	50.79
Bitumen royalties [3]	**$**	**6.62**	$	0.51	$	3.31
Transportation [1]	**$**	**1.21**	$	1.23	$	1.29

(1) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(2) Calculated as the quarterly average of the bitumen methodology price.

(3) Calculated as royalties divided by sales volumes. For SCO sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

The realized SCO sales price averaged $77.95 per bbl for 2021, an increase of 77% from $43.98 per bbl for 2020 (2019 – $70.18 per bbl). The increase in the realized SCO sales price for 2021 compared to 2020 primarily reflected the increase in WTI benchmark pricing.

The increase in bitumen royalties per bbl for 2021 from 2020 primarily reflected the impact of higher prevailing bitumen pricing and AOSP reaching full payout.

Transportation expense averaged $1.21 per bbl for 2021, comparable with $1.23 per bbl for 2020 (2019 – $1.29 per bbl).

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

($ millions)		**2021**		2020		2019
Production costs, excluding natural gas costs	**$**	**3,176**	$	2,968	$	3,151
Natural gas costs		**238**		146		125
Production costs	**$**	**3,414**	$	3,114	$	3,276

($/bbl)		**2021**		2020		2019
Production costs, excluding natural gas costs [1]	**$**	**19.45**	$	19.50	$	21.70
Natural gas costs [2]		**1.46**		0.96		0.86
Production costs [3]	**$**	**20.91**	$	20.46	$	22.56
Sales volumes (bbl/d)		**447,230**		415,741		397,735

(1) Calculated as production costs, excluding natural gas costs divided by sales volumes.

(2) Calculated as natural gas costs divided by sales volumes.

(3) Calculated as production costs divided by sales volumes.

Production costs for 2021 of $20.91 per bbl, were comparable with $20.46 per bbl for 2020 (2019 – $22.56 per bbl). Production costs per bbl for 2021 as compared to 2020 primarily reflected the impact of higher energy costs, including natural gas and diesel, offset by the impact of record production volumes, together with the Company's strong focus on cost control.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)		**2021**		2020		2019
Depletion, depreciation and amortization	**$**	**1,838**	$	1,784	$	1,656
$/bbl [1]	**$**	**11.26**	$	11.73	$	11.41

(1) Calculated as depletion, depreciation and amortization divided by sales volumes. For SCO sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

Depletion, depreciation and amortization expense for 2021 of $11.26 per bbl decreased 4% from $11.73 per bbl for 2020 (2019 – $11.41 per bbl). The decrease in depletion, depreciation and amortization on a per barrel basis primarily reflected the impact of fluctuating sales volumes from underlying operations.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)		**2021**		2020		2019
Asset retirement obligation accretion	**$**	**57**	$	72	$	61
$/bbl [1]	**$**	**0.35**	$	0.47	$	0.42

(1) Calculated as asset retirement obligation accretion divided by sales volumes. For SCO sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

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

Asset retirement obligation accretion expense for 2021 of $0.35 per bbl decreased 26% from $0.47 per bbl for 2020 (2019 – $0.42 per bbl). Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

Midstream and Refining

($ millions)	2021	2020	2019
Product sales			
Midstream activities	**$ 78**	$ 83	$ 88
NWRP, refined product sales and other	**681**	202	—
Segmented revenue	**759**	285	88
Less:			
NWRP, refining toll	**213**	166	—
Midstream activities	**21**	18	20
Production expense	**234**	184	20
NWRP, transportation and feedstock costs	**550**	181	—
Depreciation	**15**	15	14
Income from NWRP	**(400)**	—	—
Equity loss from investment in NWRP	**—**	—	287
Segmented earnings (loss)	**$ 360**	$ (95)	$ (233)

The Company's Midstream and Refining assets consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose and the Company's 50% equity investment in NWRP. Approximately 27% of the Company's heavy crude oil production was transported to international mainline liquid pipelines via the 100% owned and operated ECHO and Pelican Lake pipelines. The Midstream pipeline asset ownership allows the Company to control transportation costs, earn third party revenue, and manage the marketing of heavy crude oils.

NWRP operates a 50,000 bbl/d bitumen upgrader and refinery that processes approximately 12,500 bbl/d (25% toll payer) of bitumen feedstock for the Company and 37,500 bbl/d (75% toll payer) of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period. Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment. Production of ultra-low sulphur diesel and other refined products for 2021 averaged 69,713 BOE/d (17,428 BOE/d to the Company), reflecting the 25% toll payer commitment (2020 – 58,694 BOE/d; 14,673 BOE/d to the Company).

On June 30, 2021, the equity partners together with the toll payers, agreed to optimize the structure of NWRP to better align the commercial interests of the equity partners and the toll payers (the "Optimization Transaction"). As a result, North West Refining Inc. transferred its entire 50% partnership interest in NWRP to APMC. The Company's 50% equity interest remained unchanged.

Under the Optimization Transaction, the original term of the processing agreements was extended by 10 years from 2048 to 2058. NWRP retired higher cost subordinated debt, which carried interest rates of prime plus 6%, with lower cost senior secured bonds at an average rate of approximately 2.55%, reducing interest costs to NWRP and associated tolls to the toll payers. As such, NWRP repaid the Company's and APMC's subordinated debt advances of $555 million each. In addition, the Company received a $400 million distribution from NWRP during 2021.

To facilitate the Optimization Transaction, NWRP issued $500 million of 1.20% series L senior secured bonds due December 2023, $500 million of 2.00% series M senior secured bonds due December 2026, $1,000 million of 2.80% series N senior secured bonds due June 2031, and $600 million of 3.75% series O senior secured bonds due June 2051. Additionally, NWRP's existing $3,500 million syndicated credit facility was amended. The $2,000 million revolving credit facility was extended by three years to June 2024, and the $1,500 million non-revolving credit facility was reduced by $500 million to $1,000 million and extended by two years to June 2023. As at December 31, 2021, NWRP had borrowings of $1,981 million under the syndicated credit facility (December 31, 2020 – $2,866 million).

As at December 31, 2021, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $562 million (2020 – $153 million). The unrecognized share of the equity loss from NWRP for 2021 was $9 million and partnership distributions were $400 million (2020 – unrecognized equity loss of $94 million; 2019 – recognized equity loss of $287 million and unrecognized equity loss of $59 million).

Corporate and Other

ADMINISTRATION EXPENSE

		2021		2020		2019
Expense ($ millions)	**$**	**366**	$	391	$	344
$/BOE [1]	**$**	**0.81**	$	0.92	$	0.86
Sales volumes (BOE/d) [2]		**1,233,457**		1,166,862		1,095,379

(1) Calculated as administration expense divided by sales volumes.

(2) Total Company sales volumes.

Administration expense for 2021 of $0.81 per BOE decreased 12% from $0.92 per BOE for 2020 (2019 – $0.86 per BOE). Administration expense per BOE decreased for 2021 from 2020 primarily due to higher sales volumes and higher overhead recoveries.

SHARE-BASED COMPENSATION

($ millions)		2021		2020		2019
Expense (recovery)	**$**	**514**	$	(82)	$	223

The Company's Stock Option Plan provides employees with the right to receive common shares or a cash payment in exchange for stock options surrendered. The Performance Share Unit ("PSU") plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met.

The Company recognized a $514 million share-based compensation expense for 2021, primarily as a result of the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period, and changes in the Company's share price. An expense of $79 million related to PSUs granted to certain executive employees was included in the share-based compensation expense for 2021 (2020 – $21 million expense; 2019 – $49 million expense).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except effective interest rate)		2021		2020		2019
Interest and other financing expense	$	**711**	$	756	$	836
Interest income and other [1]		**32**		72		76
Capitalized interest [1]		**—**		24		53
Interest on long-term debt and lease liabilities [1]	$	**743**	$	852	$	965
Average current and long-term debt balance [2]	$	**18,935**	$	22,446	$	22,017
Average lease liabilities balance [2]		**1,619**		1,708		1,707
Average long-term debt and lease liabilities [2]	$	**20,554**	$	24,154	$	23,724
Average effective interest rate [3] [4]		**3.5%**		3.5%		4.0%
Interest and other financing expense per $/BOE [5]	$	**1.58**	$	1.77	$	2.09
Sales volumes (BOE/d) [6]		**1,233,457**		1,166,862		1,095,379

(1) Item is a component of interest and other financing expense.

(2) The average of current and long-term debt and lease liabilities outstanding during the respective period.

(3) This is a non-GAAP ratio and may not be comparable to similar measures presented by other companies, and should not be considered an alternative to or more meaningful than their most directly comparable financial measure presented in the Company's audited consolidated financial statements, as applicable, as an indication of the Company's performance.

(4) Calculated as the total of interest on long-term debt and lease liabilities divided by the average long-term debt and lease liabilities balance for the respective period. The Company presents its average effective interest rate for financial statement users to evaluate the Company's average cost of debt borrowings.

(5) Calculated as interest and other financing expense divided by sales volumes.

(6) Total Company sales volumes.

Interest and other financing expense per BOE for 2021 decreased 11% to $1.58 per BOE from $1.77 per BOE for 2020 (2019 – $2.09 per BOE). The decrease in interest and other financing expense per BOE for 2021 from 2020 was primarily due to higher sales volumes and lower average debt levels in 2021, partially offset by lower interest income.

The Company's average effective interest rate of 3.5% for 2021 was consistent with 2020.

RISK MANAGEMENT ACTIVITIES

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

($ millions)		**2021**		2020		2019
Natural gas financial instruments	**$**	**17**	$	16	$	(1)
Crude oil and NGLs financial instruments		**(1)**		—		52
Foreign currency contracts		**1**		16		13
Net realized loss		**17**		32		64
Natural gas financial instruments		**11**		(36)		15
Crude oil and NGLs financial instruments		**2**		—		(17)
Foreign currency contracts		**6**		(3)		15
Net unrealized loss (gain)		**19**		(39)		13
Net loss (gain)	**$**	**36**	$	(7)	$	77

During 2021, net realized risk management losses were related to the settlement of natural gas financial instruments, crude oil and NGLs financial instruments and foreign currency contracts. The Company recorded a net unrealized loss of $19 million ($16 million after-tax of $3 million) on its risk management activities for 2021 (2020 – $39 million unrealized gain, $31 million after-tax of $8 million; 2019 – $13 million unrealized loss, $14 million after-tax recovery of $1 million).

Further details related to outstanding derivative financial instruments at December 31, 2021 are disclosed in note 19 to the Company's audited consolidated financial statements.

FOREIGN EXCHANGE

($ millions)		**2021**		2020		2019
Net realized loss (gain)	**$**	**78**	$	(159)	$	(22)
Net unrealized gain		**(205)**		(116)		(548)
Net gain [(1)]	**$**	**(127)**	$	(275)	$	(570)

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

The net realized foreign exchange loss for 2021 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$500 million of 3.45% debt securities. The net unrealized foreign exchange gain for 2021 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt and the reversal of the net unrealized foreign exchange loss on the repayment of US$500 million of 3.45% debt securities. The US/Canadian dollar exchange rate at December 31, 2021 was US$0.7901 (December 31, 2020 – US$0.7840, December 31, 2019 – US$0.7713).

INCOME TAXES

($ millions, except effective tax rates)	2021	2020	2019
North America [1]	**$ 1,841**	$ (245)	$ 354
North Sea	**7**	(4)	112
Offshore Africa	**21**	17	44
PRT – North Sea	**(34)**	(31)	(89)
Other taxes	**13**	6	13
Current income tax	**1,848**	(257)	434
Deferred corporate income tax	**399**	(181)	(895)
Deferred PRT – North Sea	**—**	—	1
Deferred income tax	**399**	(181)	(894)
Income tax	**$ 2,247**	$ (438)	$ (460)
Earnings (loss) before taxes	**$ 9,911**	$ (873)	$ 4,956
Effective tax rate on net earnings (loss) [2]	**23%**	50%	(9)%
Income tax	**$ 2,247**	$ (438)	$ (460)
Tax effect on non-operating items [3] [4]	**5**	29	1,630
Current PRT – North Sea	**34**	31	89
Other taxes	**(13)**	(6)	(13)
Effective tax on adjusted net earnings (loss)	**$ 2,273**	$ (384)	$ 1,246
Adjusted net earnings (loss) from operations [5]	**$ 7,420**	$ (756)	$ 3,795
Effective tax on adjusted net earnings (loss)	**2,273**	(384)	1,246
Adjusted net earnings (loss) from operations, before taxes	**$ 9,693**	$ (1,140)	$ 5,041
Effective tax rate on adjusted net earnings (loss) from operations [6] [7]	**23%**	34%	25%

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

(2) Calculated as total of current and deferred income tax divided by earnings (loss) before taxes.

(3) Includes the net tax effect of PSUs, unrealized risk management, abandonment expenditure recovery, the Keystone XL pipeline provision and legislative changes to tax rates in adjusted net earnings (loss) from operations.

(4) During 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of this corporate income tax rate reduction, the Company's deferred corporate income tax liability decreased by $1,618 million for 2019. During 2020, the Government of Alberta substantively enacted legislation to accelerate this reduction, lowering the corporate tax rate from 10% to 8%, effective July 1, 2020. This acceleration did not have a significant impact on the Company's deferred corporate income tax liability for 2020.

(5) Non-GAAP Financial Measure. Refer to the "Non-GAAP and other Financial Measures" section of this MD&A.

(6) This is a non-GAAP ratio and may not be comparable to similar measures presented by other companies, and should not be considered an alternative to or more meaningful than their most directly comparable financial measure presented in the Company's audited consolidated financial statements, as applicable, as an indication of the Company's performance.

(7) Calculated as effective tax on adjusted net earnings (loss) divided by adjusted net earnings (loss) from operations, before taxes. The Company presents its effective tax rate on adjusted net earnings (loss) from operations for financial statement users to evaluate the Company's effective tax rate on its core business activities.

The effective tax rate on net earnings (loss) and adjusted net earnings (loss) from operations for 2021 and the comparable years included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings (loss).

The current corporate income tax and PRT in the North Sea in 2021 and the prior periods included the impact of carrybacks of abandonment expenditures related to decommissioning activities at the Company's platforms in the North Sea.

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

During 2021, the Company filed Scientific Research and Experimental Development claims of approximately $229 million (2020 – $246 million; 2019 – $250 million) relating to qualifying research and development expenditures for Canadian income tax purposes.

Net Capital Expenditures (1) (2)

($ millions)	2021	2020	2019
Exploration and Evaluation			
Net property (dispositions) acquisitions (3)	**$ (11)**	$ (31)	$ 90
Net expenditures	**12**	36	74
Total Exploration and Evaluation	**1**	5	164
Property, Plant and Equipment			
Net property acquisitions (3) (4) (5)	**1,112**	536	3,208
Well drilling, completion and equipping	**918**	429	775
Production and related facilities	**802**	580	1,028
Other	**64**	60	81
Total Property, Plant and Equipment	**2,896**	1,605	5,092
Total Exploration and Production	**2,897**	1,610	5,256
Oil Sands Mining and Upgrading			
Project costs	**236**	258	436
Sustaining capital	**1,035**	839	933
Turnaround costs	**145**	196	118
Other (6)	**331**	30	38
Total Oil Sands Mining and Upgrading	**1,747**	1,323	1,525
Midstream and Refining	**9**	5	10
Head office	**23**	19	34
Abandonments expenditures, net (2)	**232**	249	296
Net capital expenditures	**$ 4,908**	$ 3,206	$ 7,121
By segment			
North America (3) (4) (5)	**$ 2,662**	$ 1,389	$ 4,831
North Sea	**173**	122	196
Offshore Africa	**62**	99	229
Oil Sands Mining and Upgrading	**1,747**	1,323	1,525
Midstream and Refining	**9**	5	10
Head office	**23**	19	34
Abandonments expenditures, net (2)	**232**	249	296
Net capital expenditures	**$ 4,908**	$ 3,206	$ 7,121

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

(2) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(3) Includes cash consideration of $91 million for exploration and evaluation assets and $3,126 million for property, plant and equipment acquired from Devon Canada Corporation ("Devon") in 2019.

(4) Includes cash consideration of $771 million and the settlement of long-term debt of $183 million assumed in the acquisition of Storm in 2021.

(5) Includes cash consideration of $111 million and the settlement of long-term debt of $397 million assumed in the acquisition of Painted Pony Energy Ltd. ("Painted Pony") in 2020.

(6) Includes the acquisition of a 5% net carried interest on an existing oil sands lease in 2021.

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

Net capital expenditures for 2021 were $4,908 million compared with $3,206 million for 2020.

During 2021, the Company completed the acquisition of all the issued and outstanding common shares of Storm for total cash consideration of approximately $771 million. At closing, the acquisition also included the assumption of long-term debt of approximately $183 million. Storm is involved in the exploration for and development of natural gas and natural gas liquids in the Montney region of British Columbia.

During 2021, the Company also completed a number of other opportunistic acquisitions. Two acquisitions consisted of natural gas assets located in the Montney region of British Columbia. A third acquisition consisted of a net carried interest on an existing oil sands lease held by the Company, from which all Horizon production volumes are derived. Total cash consideration paid for these acquisitions was approximately $450 million.

2022 CAPITAL BUDGET

On January 11, 2022, the Company announced its 2022 base capital budget targeted at approximately $3,645 million. The budget also includes incremental strategic growth capital of approximately $700 million that targets to add future production and capacity in the Company's long life low decline thermal in situ and Oil Sands Mining and Upgrading assets.

The 2022 capital budget constitutes forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

DRILLING ACTIVITY (1)

(number of net wells)	**2021**	2020	2019
Net successful natural gas wells	**49**	30	19
Net successful crude oil wells (2)	**149**	42	86
Dry wells	**1**	—	3
Stratigraphic test / service wells	**393**	372	447
Total	**592**	444	555
Success rate (excluding stratigraphic test / service wells)	**99%**	100%	97%

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

(2) Includes bitumen wells.

North America

During 2021, the Company drilled 49 net natural gas wells, 94 net primary heavy crude oil wells, 10 net Pelican Lake heavy crude oil wells, 8 net bitumen (thermal oil) wells and 32 net light crude oil wells.

North Sea

During 2021, the Company drilled 5.9 net light crude oil wells.

Liquidity and Capital Resources

($ millions, except ratios)	2021	2020	2019
Adjusted working capital [1]	**$ (480)**	$ 626	$ 241
Long-term debt, net [2]	**$ 13,950**	$ 21,269	$ 20,843
Shareholders' equity	**$ 36,945**	$ 32,380	$ 34,991
Debt to book capitalization [2]	**27%**	40%	37%
After-tax return on average capital employed [3]	**16%**	—%	11%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.

(2) Capital Management Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(3) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

As at December 31, 2021, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Business Environment" section and in the "Risks and Uncertainties" section of this MD&A. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and market conditions. The Company continues to believe its internally generated cash flows from operating activities supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long-term and support its growth strategy.

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

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Reviewing the Company's borrowing capacity:
  - During 2021, the Company extended both of its $2,425 million revolving credit facilities originally maturing June 2022 and June 2023, to June 2024 and June 2025, respectively and increased each by $70 million. In accordance with the terms of the extension, and by mutual agreement, $70 million of the original revolving credit facilities were not extended and will mature upon the original maturity date of June 2022 and June 2023, respectively. The revolving syndicated credit facilities are extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
  - During 2021, the $1,000 million non-revolving term credit facility originally due February 2022, was extended to February 2023. Additionally in 2021, the facility was fully repaid and amended to allow for a re-draw of the full $1,000 million until March 31, 2022.
  - During 2021, the Company repaid $1,500 million of the $2,650 million non-revolving term credit facility due February 2023, reducing the outstanding balance to $1,150 million.
  - During 2019, the Company entered into a $3,250 million non-revolving term credit facility with an original maturity of June 2022, to finance the acquisition of assets from Devon. During 2021, the outstanding balance of $3,088 million was repaid and the facility was cancelled.

- During 2021, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- During 2021, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- During 2021, the Company repaid US$500 million of 3.45% debt securities.
- Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, SOFR, US base rate or Canadian prime rate.
- The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

As at December 31, 2021, the Company had undrawn bank credit facilities of $6,098 million. Including cash and cash equivalents and short-term investments, the Company had approximately $7,151 million in liquidity. Additionally, the Company had in place fully drawn term credit facilities of $1,150 million. The Company also has certain other dedicated credit facilities supporting letters of credit.

As at December 31, 2021, the Company had total US dollar denominated debt with a carrying amount of $11,581 million (US $9,151 million), before transaction costs and original issue discounts. This included $1,836 million (US$1,451 million) hedged by way of a cross currency swap (US$550 million) and foreign currency forwards (US$901 million). The fixed repayment amount of these hedging instruments is $1,805 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $31 million to $11,550 million as at December 31, 2021.

Net long-term debt was $13,950 million at December 31, 2021, resulting in a debt to book capitalization ratio of 27% (December 31, 2020 – 40%, December 31, 2019 – 37%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities are greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at December 31, 2021 are discussed in note 11 to the Company's audited consolidated financial statements.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at December 31, 2021, the Company was in compliance with this covenant.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2021 are discussed in note 19 to the Company's audited consolidated financial statements.

As at December 31, 2021, the maturity dates of long-term debt and other long-term liabilities and related interest payments were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt [1]	$ 1,000	$ 2,906	$ 3,251	$ 7,624
Other long-term liabilities [2]	$ 282	$ 181	$ 430	$ 824
Interest and other financing expense [3]	$ 650	$ 583	$ 1,503	$ 3,971

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

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, $185 million; one to less than two years, $149 million; two to less than five years, $426 million; and thereafter, $824 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2021.

SHARE CAPITAL

As at December 31, 2021, there were 1,168,369,000 common shares outstanding (December 31, 2020 – 1,183,866,000 common shares) and 38,327,000 stock options outstanding. As at March 1, 2022, the Company had 1,163,204,000 common shares outstanding and 37,112,000 stock options outstanding.

On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to $0.75 per common share, beginning with the dividend payable on April 5, 2022. On November 3, 2021, the Board of Directors approved a 25% increase in the quarterly dividend to $0.5875 per common share, from $0.47 per common share. On March 3, 2021, the Board of Directors approved an 11% increase in the quarterly dividend to $0.47 per common share, from $0.425 per common share. On March 4, 2020, the Board of Directors approved a 13% increase in the quarterly dividend to $0.425 per common share, from $0.375 per common share. On March 6, 2019, the Board of Directors approved a 12% increase in the quarterly dividend to $0.375 per common share, from $0.335 per common share. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 9, 2021, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the TSX, alternative Canadian trading platforms, and the NYSE, up to 59,278,474 common shares, over a 12-month period commencing March 11, 2021 and ending March 10, 2022.

During 2021, the Company purchased 33,644,400 common shares at a weighted average price of $46.98 per common share for a total cost of $1,581 million. Retained earnings were reduced by $1,297 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2021, the Company purchased 10,500,000 common shares at a weighted average price of $64.79 per common share for a total cost of $680 million.

On March 2, 2022, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the TSX to purchase, by way of a Normal Course Issuer Bid, up to 10% of the public float (as determined in accordance with the rules of the TSX) of its issued and outstanding common shares. Subject to acceptance of the Notice of Intention by the TSX, the purchases would be made through facilities of the TSX, alternative Canadian trading platforms, and the NYSE.

Commitments and Contingencies

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2021:

($ millions)		2022	2023	2024	2025	2026	Thereafter
Product transportation and processing [1] [2]	$	967	$ 1,107	$ 914	$ 870	$ 816	$ 10,028
North West Redwater Partnership service toll [3]	$	122	$ 123	$ 121	$ 119	$ 97	$ 3,671
Offshore vessels and equipment	$	62	$ —	$ —	$ —	$ —	$ —
Field equipment and power	$	25	$ 21	$ 21	$ 21	$ 21	$ 225
Other	$	37	$ 27	$ 22	$ 20	$ 15	$ —

(1) Includes commitments pertaining to a 20-year product transportation agreement on the Trans Mountain Pipeline Expansion.

(2) The acquisition of Storm in 2021 and Painted Pony in 2020 included approximately $298 million and $2,400 million of product transportation and processing commitments, respectively.

(3) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $1,486 million of interest payable over the 40-year tolling period, ending in 2058.

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

Reserves

For the years ended December 31, 2021 and 2020, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's total proved and total proved plus probable reserves. The evaluation and review was conducted and prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

The following are reconciliation tables of the company gross total proved and total proved plus probable reserves using forecast prices and costs as at the effective date of December 31, 2021:

Total Proved	**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, 2020	315	177	265	2,483	6,962	9,465	326	12,106
Discoveries	—	—	—	—	—	—	—	—
Extensions	1	7	—	119	—	598	15	243
Infill Drilling	3	4	—	—	—	170	13	47
Improved Recovery	—	—	1	19	—	3	—	21
Acquisitions	—	—	—	—	—	1,715	59	345
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	14	13	22	—	—	309	10	110
Technical Revisions	(5)	(9)	2	105	199	528	13	392
Production	(28)	(23)	(20)	(95)	(164)	(619)	(18)	(451)
December 31, 2021 (1)	**300**	**169**	**270**	**2,631**	**6,998**	**12,168**	**418**	**12,813**

Total Proved Plus Probable	**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, 2020	463	260	395	4,157	7,496	15,922	500	15,925
Discoveries	—	—	—	—	—	—	—	—
Extensions	2	10	—	158	—	1,004	30	368
Infill Drilling	4	6	—	—	—	687	21	146
Improved Recovery	—	—	2	23	—	4	—	26
Acquisitions	—	—	—	—	—	2,979	100	596
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	18	18	7	2	—	368	11	116
Technical Revisions	(34)	(22)	5	91	202	(94)	(1)	224
Production	(28)	(23)	(20)	(95)	(164)	(619)	(18)	(451)
December 31, 2021 (1)	**424**	**249**	**388**	**4,337**	**7,535**	**20,249**	**643**	**16,950**

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

At December 31, 2021, the total proved crude oil, bitumen (thermal oil) and NGLs reserves were 10,785 MMbbl, and total proved plus probable crude oil, bitumen (thermal oil) and NGLs reserves were 13,576 MMbbl. Total proved reserves additions and revisions replaced 174% of 2021 production. Additions to total proved reserves resulting from exploration and development activities, acquisitions, dispositions and future offset additions amounted to 241 MMbbl, and additions to total proved plus probable reserves amounted to 357 MMbbl. Net positive revisions amounted to 363 MMbbl for total proved reserves and 295 MMbbl for total proved plus probable reserves, primarily due to technical revisions.

At December 31, 2021, the total proved natural gas reserves were 12,168 Bcf, and total proved plus probable natural gas reserves were 20,249 Bcf. Total proved reserves additions and revisions replaced 537% of 2021 production. Additions to total proved reserves resulting from exploration and development activities, acquisitions, dispositions and future offset additions amounted to 2,485 Bcf, and additions to total proved plus probable reserves amounted to 4,673 Bcf. Net positive revisions amounted to 837 Bcf for total proved reserves, primarily due to technical revisions and economic factors. Net positive revisions amounted to 273 Bcf for total proved plus probable reserves, primarily due to economic factors.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators to review the qualifications of and

procedures used by each evaluator in determining the estimate of the Company's quantities and related net present value of future net revenue of the remaining reserves. Additional reserves information is annually disclosed in the AIF.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States FASB Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual report on Form 40-F filed with the SEC and in the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

Risks and Uncertainties

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

- Volatility in the prevailing prices of crude oil and NGLs, natural gas and refined products;
- The ability to find, produce and replace reserves, whether sourced from exploration, improved recovery or acquisitions, at a reasonable cost, including the risk of reserves revisions due to economic and technical factors. Reserves revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Reservoir quality and uncertainty of reserves estimates;
- Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
- Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting and upgrading the Company's bitumen products;
- Timing and success of integrating the business and operations of acquired companies and assets;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
- Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
- Foreign exchange risk due to the effect of fluctuating exchange rates on the Company's US dollar denominated debt and revenue from sales predominantly based on US dollar denominated benchmarks;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Future legislative and regulatory developments related to environmental regulation, including but not limited to GHG compliance costs and reduction targets;
- The timing and pace of change to a low carbon economy is uncertain and the ability to access insurance and capital may be adversely affected in the event that financial institutions, investors, insurers, rating agencies and/or lenders adopt more restrictive decarbonisation policies;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations, including but not limited to restrictions on production and the certainty and timelines for regulatory processes;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;
- Changing royalty regimes;
- Business interruptions because of unexpected events such as fires or explosions whether caused by human error or nature, severe storms and other calamitous acts of nature, blowouts, freeze-ups, mechanical or equipment failures of facilities and infrastructure and other similar events affecting the Company or other parties whose operations or assets directly or indirectly impact the Company and that may or may not be financially recoverable;
- Epidemics or pandemics, such as COVID-19, 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 the 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 international demand for commodities and have a corresponding impact on the prices realized by the Company, which could have a material adverse effect on the Company's financial condition;
- The ability to secure adequate transportation for products, which could be affected by pipeline constraints, the construction by third parties of new or expansion of existing pipeline capacity and other factors;

- The access to markets for the Company’s products;
- The risk of significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach that could adversely affect the Company's operations;
- Liquidity risk related to the Company's ability to fulfill financial obligations as they become due or ability to liquidate assets in a timely manner at a reasonable price; and
- Other circumstances affecting revenue and expenses.

The Company uses a variety of means to seek to mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company seeks to manage these risks by monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default. Derivative financial instruments are periodically utilized to help ensure targets are met and to manage commodity price, foreign currency and interest rate exposures. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company seeks to manage this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. The arrangements and policies concerning the Company’s financial instruments are under constant review and may change depending upon the prevailing market conditions. Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper and access to debt capital markets, to meet obligations as they become due. The Company has implemented cyber security protocols and procedures designed to reduce the risk of failure or a significant breach of the Company’s information technology systems and related data and control systems.

The Company has safety, integrity and environmental management systems to recover and process crude oil and natural gas resources safely, efficiently, and in an environmentally sustainable manner and mitigate risk.

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

For additional details regarding the Company’s risks and uncertainties, refer to the Company’s AIF for the year ended December 31, 2021.

Environment

The Company has a Corporate Statement on Environmental Management that affirms environmental stewardship as a fundamental value of the Company. The Company continues to invest in people, proven and new technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner. Environmental, social, economic and health considerations are evaluated in new project designs and in operations to improve environmental performance. Processes are employed to avoid, mitigate, minimize or compensate for environmental effects. Working with local communities, the Company considers the interests and values of the people using the land in proximity to its operations, and where appropriate, adapts projects to recognize those matters.

The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation compliance, particularly in North America and the North Sea. Existing and expected legislation and regulations may require the Company to address and mitigate the effect of its activities on the environment. The Company believes it meets all existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. Increasingly stringent laws and regulations may have an adverse effect on the Company’s future net earnings.

The Company’s associated environmental risk management strategies incorporate working with legislators and regulators on any new or revised policies, legislation or regulations to reflect a balanced approach to sustainable development. Specific measures in response to existing or new legislation include a focus on the Company’s energy efficiency, air emissions management, water management and land management to minimize disturbance impacts. The Company’s environmental risk management strategies employ an Environmental Management Plan (the "Plan"). As part of risk management, the Company develops, assesses and implements technologies and innovative practices that will improve environmental performance, often through collaborative efforts with industry partners, governments and research institutions. Details of the Plan, along with performance results, are presented to, and reviewed by, the Board of Directors quarterly.

The Plan and the Company's operating guidelines focus on minimizing the impact of operations while meeting regulatory requirements, regional management frameworks for air quality and emissions, ground and surface water and biodiversity, industry operating standards and guidelines, and internal corporate standards. Training and due diligence for operators and contractors is key to the effectiveness of the Company's environmental management programs and the prevention of incidents to protect the environment. The Company, as part of this Plan, has implemented proactive programs that include:

- Environmental planning to assess impacts and implement avoidance and mitigation programs in order to maintain biodiversity for terrestrial and aquatic systems and high value ecosystems;
- Continued evaluation of new technologies to reduce environmental impacts, including support for Canada's Oil Sands Innovation Alliance ("COSIA"), Petroleum Technology Alliance Canada ("PTAC") and other research institutions;
- Mitigation of the Company's climate change impacts through implementation of various CO_2 emissions reduction and carbon capture projects including: CO_2 injection for EOR, CO_2 injection in tailings and the Quest Carbon Capture and Storage Facility; a methane emissions reduction program, including solution gas conservation to reduce methane venting, and an equipment retrofit program to reduce methane emissions from pneumatic equipment; and optimization of efficiencies at the Company's facilities;
- Water programs to improve efficiency of use and recycle rates as well as to reduce fresh water use;
- Groundwater monitoring for all thermal in situ and mine operations;
- Effective reclamation and decommissioning programs across the Company's operations, returning sites to their former state. In North America, well abandonment and progressive reclamation of large contiguous areas of land provides the foundation for the enhancement of biodiversity and functional wildlife habitats. In the Company's International operations, decommissioning activities were completed at Murchison and were advanced at Banff, Kyle, and Ninian North;
- Tailings management in Oil Sands Mining to minimize fine tailings and promote progressive reclamation;
- Monitoring programs to assess changes to biodiversity, wildlife and fisheries in order to manage construction and operation effects and to assess reclamation success;
- Participation and support for the Oil Sands Monitoring Program of regional important resources;
- An active spill prevention and management program; and
- An internal environmental management system for compliance audit and inspection programs of operating facilities.

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.0% (2020 – 3.7%; 2019 – 3.8%). For 2021, the Company's capital expenditures included $307 million for abandonment expenditures ($232 million – abandonment expenditures, net) (2020 – $249 million; 2019 – $296 million). Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A for further details on abandonments expenditures, net. The Company's estimated discounted ARO at December 31, 2021 was as follows:

($ millions)		**2021**		2020
Exploration and Production				
North America	**$**	**4,021**	$	2,899
North Sea		**821**		787
Offshore Africa		**170**		174
Oil Sands Mining and Upgrading		**1,793**		1,999
Midstream and Refining		**1**		2
	$	**6,806**	$	5,861

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine sites, upgrading facilities and tailings, and offshore production platforms. Factors that affect costs include number of wells drilled, well depth, facility size and the specific environmental legislation. The estimated future costs are based on engineering estimates of current costs in accordance with present legislation, industry operating practice and the expected timing of abandonment.

In 2021, the Alberta Energy Regulator announced a new Liability Management Framework, enforcing mandatory targets for companies for the closure of inactive wells and facilities. These targets became effective January 1, 2022. The Company has updated its forecasts of future expenditures to settle its ARO liability based on the set and forecasted annual targets. As a result, the Company's ARO liability as at December 31, 2021 has increased on an inflated and discounted basis due to earlier forecasted expenditures to settle liabilities associated with the closure of inactive well and facilities located in Alberta.

GREENHOUSE GAS AND OTHER EMISSIONS

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

The Company is participating in the Oil Sands Pathways to Net Zero initiative, an alliance of oil sands producers working collectively with federal and provincial governments, to achieve net zero GHG emissions from oil sands operations by 2050 to help Canada meet its climate goals, including its Paris Agreement commitments and 2050 net zero aspirations.

The Company, through industry associations, is working with Canadian legislators and regulators as they develop and implement new GHG emission laws and regulations to support emissions reductions and properly reflect a balanced approach to sustainable development. Internally, the Company is pursuing an integrated emissions reduction strategy, to ensure that it is able to comply with existing and future emissions reduction requirements, for both GHGs and air pollutants (such as sulphur dioxide and oxides of nitrogen). The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new policies encourage technological innovation, energy efficiency, and targeted research and development while not impacting competitiveness.

Governments in jurisdictions in which the Company operates have developed or are developing GHG regulations as part of their national and international climate change commitments. The Company uses existing GHG regulations to determine the impact of compliance costs on current and future projects. The Company monitors the development of GHG regulations on an ongoing basis in the jurisdictions in which it operates to assess the impact of future regulatory developments on the Company's operations and planned projects. In Canada, the federal government has ratified the Paris climate change agreement, with a commitment to reduce GHG emissions by 40 - 45% from 2005 levels by 2030. The Canadian government has also committed to cap and cut emissions from the oil and gas sector, with further details to be developed in 2022. Canada has also committed to reduce methane emissions from the upstream oil and natural gas sector by 40 - 45% by 2025, and by 75% by 2030, as compared to 2012 levels for both the 2025 and 2030 targets. In December 2020, the federal government announced its intention to increase the carbon price to $170/tonne in 2030. 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. Draft regulations under the Clean Fuel Standard were released in 2020 and are planned to take effect in December 2022. Aspects of the Clean Fuel Standard could potentially increase the cost of liquid fuels consumed in the Company's operations while also providing a potential mechanism to generate offset credits. The final version of the Clean Fuel regulations are expected to be published in 2022.

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, 2020, the GHG regulation (the Carbon Competitiveness Incentive Regulation) 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 was $40/tonne for emissions above the TIER-regulated limits in 2021 and is $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 and the North West Redwater bitumen upgrader and refinery are also subject to compliance under the regulations.

In British Columbia, carbon tax is currently being assessed at $45/tonne of CO_2e on fuel consumed and gas flared and vented in the province. In February 2021, the British Columbia government announced that the carbon tax rate would increase to $50/tonne effective April 1, 2022. The British Columbia government has implemented 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 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 required the North Tangleflags in situ heavy oil facility and the Senlac in situ heavy crude oil facility to meet reduction targets for GHG emissions in 2020. This regulation also enables facilities below the threshold to aggregate and opt into the Saskatchewan regulatory system as an alternative to the federal fuel charge.

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

By 2025, the federal government has committed to reduce methane emissions from the oil and gas sector by 40% to 45% below 2012 levels. 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, under which the federal regulation would not be in effect for those jurisdictions. The provinces of British Columbia, Alberta and Saskatchewan have implemented provincial methane regulations, and have reached equivalency agreements with the federal government. Accordingly, the applicable provincial methane regulations govern in the three western provinces whereas the federal methane regulation applies to methane emissions in the province of Manitoba.

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

In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 - 2007) of the UK National Allocation Plan, the Company operated below its CO_2 allocation. In Phase 2 (2008 - 2012) the Company's CO_2 allocation was decreased below the Company's operations emissions. In Phase 3 (2013 - 2020) the Company's CO_2 allocation was further reduced. Following the UK's withdrawal from the European Union ("EU") on January 31, 2020, a new UK Emissions Trading Scheme ("ETS") was launched on January 1, 2021. The new scheme is currently aligned with the EU ETS rules and applies to energy intensive industries, the power generation sector and aviation. The Company continues to focus on implementing CO_2 emission reduction program opportunities at its facilities and on trading mechanisms to ensure compliance with requirements now in effect.

Accounting Policies and Standards

REGULATORY DEVELOPMENTS

On May 27, 2021, the Canadian Securities Administrators ("CSA") announced the adoption of NI 52-112 and related amendments. This National Instrument replaces the previous CSA staff notice on Non-GAAP Measures. NI 52-112 governs how entities present non-GAAP and other financial measures and ratios. The requirements apply to the Company's MD&A and certain other disclosure documents for the year ended December 31, 2021.

CHANGES IN ACCOUNTING POLICIES

In August 2020, the IASB issued Interest Rate Benchmark Reform (Phase 2) in response to the Financial Stability Board's mandated reforms to IBORs, with financial regulators proposing that current IBOR benchmark rates be replaced by a number of new local currency denominated alternative benchmark rates. The Company adopted the amendments on January 1, 2021. Adoption of these amendments did not have a significant impact on the Company's financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. In 2021, COVID-19 continued to have an impact on the global economy, including the oil and gas industry. Business conditions in 2021 continued to reflect the market uncertainty associated with COVID-19. The Company has taken into account the impacts of COVID-19 and the unique circumstances it has created in making estimates, assumptions, and judgements in the preparation of the audited consolidated financial statements, and continues to monitor the developments in the business environment and commodity market. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in this MD&A and the audited consolidated financial statements for the year ended December 31, 2021.

A) Depletion, Depreciation and Amortization and Impairment

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

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

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

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

The Company assesses property, plant and equipment for impairment discounted at rates currently ranging from 10% to 12% whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low commodity prices for an extended period, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs an impairment test related to the specific assets at the CGU level.

B) Crude Oil and Natural Gas Reserves

Reserves estimates are based on engineering data, estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations and judgements, including the potential impact of climate related matters and in accordance with related government regulations. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion, depreciation and amortization charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of E&E and property, plant and equipment carrying amounts.

C) Asset Retirement Obligations

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

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company’s weighted average credit-adjusted risk-free interest rate, which is currently 4.0%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

D) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted that are expected to apply when the asset or liability is recovered. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

E) Risk Management Activities

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

F) Purchase Price Allocations

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

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

G) Share-Based Compensation

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

H) Leases

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

I) Government Grants

The Company receives or is eligible for government grants, including emissions credits and grants introduced in response to the impact of COVID-19. Government grants are recognized in net earnings when there is reasonable assurance that the Company will comply with the conditions attached to the grant and the grant will be received. Emissions performance and offset credits generated under the Alberta TIER regulation are initially recorded at fair value as determined by the prescribed Alberta TIER fund compliance rates in effect at the time the credits are recognized.

Control Environment

The Company's management, including the President and the Chief Financial Officer and Vice-President, Finance and Principal Accounting Officer, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2021, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized and reported within the time periods specified and such information is accumulated and communicated to the Company's management to allow timely decisions regarding required disclosures.

The Company's management, including the President and the Chief Financial Officer and Vice-President, Finance and Principal Accounting Officer, also evaluated the effectiveness of internal control over financial reporting as at December 31, 2021, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2021 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal control over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Non-GAAP and Other Financial Measures

This MD&A includes references to non-GAAP and other financial measures as defined in NI 52-112. These financial measures are used by the Company to evaluate its financial performance, financial position or cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies, and should not be considered an alternative to or more meaningful than the most directly comparable financial measure presented in the Company's audited consolidated financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this MD&A, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below.

ADJUSTED NET EARNINGS (LOSS) FROM OPERATIONS

Adjusted net earnings (loss) from operations is a non-GAAP financial measure that adjusts net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), for non-operating items (after-tax). The Company considers adjusted net earnings (loss) from operations a key measure in evaluating its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. A reconciliation for adjusted net earnings (loss) from operations is presented below.

($ millions)	**2021**	2020	2019
Net earnings (loss)	**$ 7,664**	$ (435)	$ 5,416
Share-based compensation, net of tax [1]	**495**	(86)	210
Unrealized risk management loss (gain), net of tax [2]	**16**	(31)	14
Unrealized foreign exchange gain, net of tax [3]	**(205)**	(116)	(548)
Realized foreign exchange loss (gain), net of tax [4]	**118**	(166)	—
Gain on acquisitions, net of tax [5]	**(478)**	(217)	—
(Gain) loss from investments, net of tax [6]	**(132)**	185	321
Other, net of tax [7]	**(58)**	110	—
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities [8]	**—**	—	(1,618)
Non-operating items (after-tax)	**(244)**	(321)	(1,621)
Adjusted net earnings (loss) from operations	**$ 7,420**	$ (756)	$ 3,795

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and PSU plan. The fair value of the share-based compensation is recognized as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings (loss). Pre-tax share-based compensation for 2021 was an expense of $514 million (2020 – $82 million recovery; 2019 – $223 million expense).

(2) Derivative financial instruments are recognized at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings (loss). The amounts ultimately realized may be materially different than those amounts reflected in the Company's audited consolidated financial statements due to changes in prices of the underlying items hedged, primarily natural gas and foreign exchange. Pre-tax unrealized risk management loss for 2021 was $19 million (2020 – $39 million gain; 2019 – $13 million loss).

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

(4) During 2021, the Company repaid US$500 million of 3.45% debt securities, resulting in a pre- and after-tax foreign exchange loss of $118 million. During 2020, the Company settled the US$500 million cross currency swaps designated as cash flow hedges of the US$500 million 3.45% US dollar debt securities due November 2021. The Company realized cash proceeds of $166 million on settlement. There was net zero tax impact on the settlement.

(5) During 2021, the Company completed two acquisitions resulting in a pre- and after-tax gain of $478 million. During 2020, the Company recognized a pre- and after-tax gain of $217 million related to the acquisition of Painted Pony.

(6) The Company's investments in PrairieSky and IPL have been accounted for at fair value through profit and loss and are measured each period with (gains) losses recognized in net earnings (loss). There is net zero tax impact on these (gains) losses from investment.

(7) During 2021, the Company recognized the impact of government grant income under the provincial well-site rehabilitation programs of $75 million ($58 million after-tax). During 2020, the Company recognized a provision in transportation, blending and feedstock expense of $143 million ($110 million after-tax) relating to the Keystone XL pipeline project.

(8) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to the underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recognized in net earnings (loss) during the period the legislation is substantively enacted. During 2019, the Company's deferred corporate income tax liability decreased by $1,618 million, refer to "Income Taxes" section of this MD&A.

ADJUSTED FUNDS FLOW

Adjusted funds flow is a non-GAAP financial measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment expenditures excluding the impact of government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets. The Company considers adjusted funds flow a key measure in evaluating its performance, as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. A reconciliation for adjusted funds flow, from cash flows from operating activities is presented below.

($ millions)		**2021**		2020		2019
Cash flows from operating activities	**$**	**14,478**	$	4,714	$	8,829
Net change in non-cash working capital		**(964)**		166		1,033
Abandonment expenditures, net [(1)]		**232**		249		296
Movements in other long-term assets [(2)]		**(13)**		71		109
Adjusted funds flow	**$**	**13,733**	$	5,200	$	10,267

(1) Non-GAAP Financial Measure. A reconciliation of abandonment expenditures, net is presented in the "Abandonment Expenditures, net" section below.

(2) Includes the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to NWRP and prepaid cost of service tolls.

ADJUSTED NET EARNINGS (LOSS) FROM OPERATIONS AND ADJUSTED FUNDS FLOW, PER SHARE (BASIC AND DILUTED)

Adjusted net earnings (loss) from operations and adjusted funds flow, per share (basic and diluted), are non-GAAP ratios that represent those non-GAAP measures divided by the weighted average number of basic and diluted common shares outstanding for the period, respectively, as presented in note 17 to the Company's audited consolidated financial statements.

ABANDONMENT EXPENDITURES, NET

Abandonment expenditures, net, is a non-GAAP financial measure that represents the abandonment expenditures to settle asset retirement obligations as reflected in the Company's annual capital budget. Abandonment expenditures, net is calculated as abandonment expenditures, as presented in the Company's audited consolidated Statements of Cash Flows, adjusted for the impact of government grant income under the provincial well-site rehabilitation programs. A reconciliation of abandonment expenditures, net is presented below.

($ millions)		**2021**		2020		2019
Abandonment expenditures	**$**	**307**	$	249	$	296
Government grants for abandonment expenditures		**(75)**		—		—
Abandonment expenditures, net	**$**	**232**	$	249	$	296

NETBACK

Netback is a non-GAAP ratio that represents net cash flows provided from core activities after the impact of all costs associated with bringing a product to market, on a per unit basis. The Company considers netback a key measure in evaluating its performance, as it demonstrates the efficiency and profitability of the Company's activities. Refer to the "Operating Highlights – Exploration and Production", "Per Unit Results – Exploration and Production", and "Per Unit Results – Oil Sands Mining and Upgrading" sections of this MD&A for the netback calculations on a per unit basis for crude oil and NGLs, natural gas and on a total barrels of oil equivalent basis.

The netback calculations include the non-GAAP financial measures: realized price and transportation, reconciled below to their respective line item in note 22 to the Company's audited consolidated financial statements.

REALIZED PRICE ($/BBL AND $/BOE) – EXPLORATION AND PRODUCTION

Realized price ($/bbl and $/BOE) is a non-GAAP ratio calculated as realized crude oil and NGLs sales and total realized BOE sales (non-GAAP financial measures) divided by respective sales volumes. Realized crude oil and NGLs sales and total realized BOE sales include the impact of blending costs and other by-product sales. The Company considers realized price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit the Company obtained on the market for its crude oil and NGLs sales volumes and BOE sales volumes.

Reconciliations for Exploration and Production realized crude oil and NGLs sales and BOE sales and the calculations for realized price are presented below.

($ millions, except bbl/d and $/bbl)	Q1	Q2	Q3	Q4	2021	2020	2019
Crude oil and NGLs (bbl/d)							
North America	**477,768**	**468,265**	**448,948**	**490,448**	**471,331**	465,073	400,853
North Sea	**29,566**	**8,939**	**16,028**	**21,360**	**18,942**	22,852	27,171
Offshore Africa	**10,843**	**17,932**	**19,402**	**5,624**	**13,452**	17,017	21,056
Sales volumes	**518,177**	**495,136**	**484,378**	**517,432**	**503,725**	504,942	449,080
Crude oil and NGLs sales (1) (2)	**$ 3,373**	**$ 3,655**	**$ 3,810**	**$ 4,667**	**$ 15,505**	$ 8,215	$ 11,183
Less: Blending costs (3)	**916**	**897**	**777**	**1,202**	**3,792**	2,321	2,155
Realized crude oil and NGLs sales	**$ 2,457**	**$ 2,758**	**$ 3,033**	**$ 3,465**	**$ 11,713**	$ 5,894	$ 9,028
Realized price ($/bbl)	**$ 52.68**	**$ 61.20**	**$ 68.06**	**$ 72.81**	**$ 63.71**	$ 31.90	$ 55.08

(1) Crude oil and NGLs sales in note 22 to the Company's audited consolidated financial statements.

(2) Includes other miscellaneous income in the segment.

(3) Blending costs are a component of transportation, blending and feedstock expense as reconciled below in the "Transportation – Exploration and Production" section.

($ millions, except BOE/d and $/BOE)	Q1	Q2	Q3	Q4	2021	2020	2019
Barrels of oil equivalent (BOE/d)							
North America	**741,904**	**733,874**	**731,962**	**797,185**	**751,330**	706,799	641,327
North Sea	**30,180**	**9,624**	**16,427**	**21,940**	**19,512**	24,805	31,167
Offshore Africa	**12,444**	**20,659**	**20,652**	**7,781**	**15,385**	19,517	25,151
Sales volumes	**784,528**	**764,157**	**769,041**	**826,906**	**786,227**	751,121	697,645
Barrels of oil equivalent sales (1) (2)	**$ 3,865**	**$ 4,119**	**$ 4,460**	**$ 5,581**	**$ 18,025**	$ 9,511	$ 12,457
Less: Blending costs (3)	**916**	**897**	**777**	**1,202**	**3,792**	2,321	2,155
Less: Sulphur (income) expense	**(2)**	**(4)**	**(3)**	**(12)**	**(21)**	4	(12)
Realized barrels of oil equivalent sales	**$ 2,951**	**$ 3,226**	**$ 3,686**	**$ 4,391**	**$ 14,254**	$ 7,186	$ 10,314
Realized price ($/BOE)	**$ 41.80**	**$ 46.40**	**$ 52.09**	**$ 57.72**	**$ 49.67**	$ 26.15	$ 40.50

(1) Barrels of oil equivalent sales includes crude oil and NGLs sales and natural gas sales in note 22 to the Company's audited consolidated financial statements.

(2) Includes other miscellaneous income in the segment.

(3) Blending costs are a component of transportation, blending and feedstock expense as reconciled below in the "Transportation – Exploration and Production" section.

TRANSPORTATION – EXPLORATION AND PRODUCTION

Transportation ($/BOE, $/bbl and $/Mcf) is a non-GAAP ratio calculated as transportation (a non-GAAP financial measure) divided by the respective sales volumes. The Company calculates transportation to demonstrate its cost to deliver products to the market excluding the impact of blending costs. A reconciliation for Exploration and Production transportation and the calculations for transportation are presented below.

($ millions, except $ per unit amounts)	Q1	Q2	Q3	Q4	2021	2020	2019
Transportation, blending and feedstock [1]	**$ 1,148**	**$ 1,146**	**$ 1,025**	**$ 1,461**	**$ 4,780**	$ 3,409	$ 2,956
Less: Blending costs	**916**	**897**	**777**	**1,202**	**3,792**	2,321	2,155
Less: Other [2]	**—**	**—**	**—**	**—**	**—**	143	—
Transportation	**$ 232**	**$ 249**	**$ 248**	**$ 259**	**$ 988**	$ 945	$ 801
Transportation ($/BOE)	**$ 3.29**	**$ 3.58**	**$ 3.50**	**$ 3.40**	**$ 3.44**	$ 3.44	$ 3.14
Amounts attributed to crude oil and NGLs	**$ 166**	**$ 179**	**$ 178**	**$ 187**	**$ 710**	$ 711	$ 571
Transportation ($/bbl)	**$ 3.56**	**$ 3.98**	**$ 4.00**	**$ 3.93**	**$ 3.86**	$ 3.85	$ 3.48
Amounts attributed to natural gas	**$ 66**	**$ 70**	**$ 70**	**$ 72**	**$ 278**	$ 234	$ 230
Transportation ($/Mcf)	**$ 0.46**	**$ 0.48**	**$ 0.44**	**$ 0.42**	**$ 0.45**	$ 0.43	$ 0.42

(1) Transportation, blending and feedstock in note 22 to the Company's audited consolidated financial statements.

(2) Transportation excludes the impact of a $143 million provision recognized in 2020, relating to the Keystone XL pipeline project.

NORTH AMERICA – REALIZED PRODUCT PRICES AND ROYALTIES

Realized crude oil and NGLs price ($/bbl) is a non-GAAP ratio calculated as realized crude oil and NGLs sales (non-GAAP financial measure) divided by sales volumes. Realized crude oil and NGLs sales include the impact of blending costs. The Company considers the realized crude oil and NGLs price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its crude oil and NGLs sales volumes.

Crude oil and NGLs royalty rate is a non-GAAP ratio that is calculated as crude oil and NGLs royalties divided by realized crude oil and NGLs sales. The Company considers crude oil and NGLs royalty rate a key measure in evaluating its performance, as it describes the Company's royalties for crude oil and NGLs sales volumes on a per unit basis.

A reconciliation for North America realized crude oil and NGLs sales and the calculations for realized crude oil and NGLs prices and the royalty rates are presented below.

($ millions, except $/bbl and royalty rates)	2021	2020	2019
Crude oil and NGLs sales [1]	**$ 14,478**	$ 7,480	$ 9,679
Less: Blending costs [2]	**3,792**	2,321	2,155
Realized crude oil and NGLs sales	**$ 10,686**	$ 5,159	$ 7,524
Realized crude oil and NGLs prices ($/bbl)	**$ 62.10**	$ 30.31	$ 51.43
Crude oil and NGLs royalties [3]	**$ 1,558**	$ 464	$ 959
Crude oil and NGLs royalty rates	**15%**	9%	13%

(1) Crude oil and NGLs sales in note 22 to the Company's audited consolidated financial statements.

(2) Blending costs are a component of transportation, blending and feedstock expense as reconciled above in the "Transportation – Exploration and Production" section.

(3) Item is a component of royalties in note 22 to the Company's audited consolidated financial statements.

REALIZED PRODUCT PRICES AND TRANSPORTATION – OIL SANDS MINING AND UPGRADING

Realized SCO sales price ($/bbl) is a non-GAAP ratio calculated as realized SCO sales (non-GAAP financial measure) including the impact of blending and feedstock costs, divided by SCO sales volumes. The Company considers realized SCO sales price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its SCO sales volumes.

Transportation ($/bbl) is a non-GAAP ratio calculated as transportation (a non-GAAP financial measure) divided by SCO sales volumes. The Company calculates transportation to demonstrate its cost to deliver product to the market excluding the impact of blending and feedstock costs.

Reconciliations for Oil Sands Mining and Upgrading realized SCO sales and transportation and the calculations for realized SCO sales price and transportation are presented below.

($ millions, except for bbl/d and $/bbl)	Q1	Q2	Q3	Q4	2021	2020	2019
SCO sales volumes (bbl/d)	**469,953**	**366,843**	**467,772**	**483,972**	**447,230**	415,741	397,735
Crude oil and NGLs sales [1] [2]	**$ 2,983**	**$ 2,794**	**$ 3,848**	**$ 4,408**	**$ 14,033**	$ 7,389	$ 11,307
Less: Blending and feedstock costs	**251**	**251**	**339**	**468**	**1,309**	695	1,119
Realized SCO sales	**$ 2,732**	**$ 2,543**	**$ 3,509**	**$ 3,940**	**$ 12,724**	$ 6,694	$ 10,188
Realized SCO sales price ($/bbl)	**$ 64.60**	**$ 76.19**	**$ 81.54**	**$ 88.48**	**$ 77.95**	$ 43.98	$ 70.18
Transportation, blending and feedstock [3]	**$ 297**	**$ 294**	**$ 387**	**$ 527**	**$ 1,505**	$ 881	$ 1,306
Less: Blending and feedstock costs	**251**	**251**	**339**	**468**	**1,309**	695	1,119
Transportation	**$ 46**	**$ 43**	**$ 48**	**$ 59**	**$ 196**	$ 186	$ 187
Transportation ($/bbl)	**$ 1.10**	**$ 1.26**	**$ 1.14**	**$ 1.33**	**$ 1.21**	$ 1.23	$ 1.29

(1) Crude oil and NGLs sales in note 22 to the Company's audited consolidated financial statements.

(2) Excludes other miscellaneous income not pertaining to crude oil and NGLs sales.

(3) Transportation, blending and feedstock in note 22 to the Company's audited consolidated financial statements.

NET CAPITAL EXPENDITURES

Net capital expenditures is a non-GAAP financial measure that represents cash flows used in investing activities as presented in the Company's audited consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, proceeds from investment, the repayment of NWRP subordinated debt advances, abandonment expenditures including the impact of government grant income under the provincial well-site rehabilitation programs, and the settlement of long-term debt assumed in acquisitions. The Company considers net capital expenditures a key measure in evaluating its performance, as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. A reconciliation of net capital expenditures is presented below.

($ millions)	2021	2020	2019
Cash flows used in investing activities	**$ 3,703**	$ 2,819	$ 7,255
Net change in non-cash working capital [1]	**107**	(383)	(430)
Proceeds from investment	**128**	—	—
Repayment of NWRP subordinated debt advances	**555**	124	—
Capital expenditures	**4,493**	2,560	6,825
Abandonment expenditures, net [2]	**232**	249	296
Settlement of long-term debt acquired [3]	**183**	397	—
Net capital expenditures	**$ 4,908**	$ 3,206	$ 7,121

(1) Includes net working capital and other long-term assets of $195 million related to the acquisition of assets from Devon in 2019.

(2) Non-GAAP Financial Measure. A reconciliation of abandonment expenditures, net is presented in the "Abandonment Expenditures, net" section above.

(3) Relates to the settlement of long-term debt assumed in the acquisition of Storm in 2021 and Painted Pony in 2020.

LIQUIDITY

Liquidity is a non-GAAP financial measure that represents the availability of readily available undrawn bank credit facilities, cash and cash equivalents, and other highly liquid assets to meet short-term funding requirements and to assist in assessing the Company's financial position. The following is the Company's calculation of liquidity:

($ millions)		**2021**		2020		2019
Undrawn bank credit facilities	**$**	**6,098**	$	4,958	$	4,737
Cash and cash equivalents		**744**		184		139
Investments		**309**		305		490
Liquidity	**$**	**7,151**	$	5,447	$	5,366

LONG-TERM DEBT, NET

Long-term debt, net, is a capital management measure that represents long-term debt less cash and cash equivalents, as disclosed in note 16 to the Company's audited consolidated financial statements.

DEBT TO BOOK CAPITALIZATION

Debt to book capitalization is a capital management measure intended to enable financial statement users to evaluate the Company's capital structure, as disclosed in note 16 to the Company's audited consolidated financial statements.

AFTER-TAX RETURN ON AVERAGE CAPITAL EMPLOYED

After-tax return on average capital employed as defined by the Company is a non-GAAP ratio. The ratio is calculated as net earnings (loss) plus after-tax interest and other financing expense for the twelve month trailing period; as a percentage of average capital employed (defined as current and long-term debt plus shareholders' equity) for the twelve month trailing period. The Company considers this ratio a key measure in evaluating the Company's ability to generate profit and the efficiency with which it employs capital. A reconciliation of the Company's after-tax return on average capital employed is presented below.

($ millions, except ratios)		**2021**		2020		2019
Interest adjusted after-tax return:						
Net earnings (loss), 12 months trailing	**$**	**7,664**	$	(435)	$	5,416
Interest and other financing expense, net of tax, 12 months trailing [(1)]		**547**		571		612
Interest adjusted after-tax return	**$**	**8,211**	$	136	$	6,028
12 months average current portion long-term debt [(2)]	**$**	**1,483**	$	1,842	$	2,640
12 months average long-term debt [(2)]		**16,769**		20,162		19,078
12 months average common shareholders' equity [(2)]		**34,458**		33,026		33,660
12 months average capital employed	**$**	**52,710**	$	55,030	$	55,378
After-tax return on average capital employed		**16%**		—%		11%

(1) The blended tax rate on interest was 23% for December 31, 2021, 24% for December 31, 2020, and 27% for December 31, 2019.

(2) For the purpose of this non-GAAP ratio, the measurement of average current and long-term debt and common shareholders equity are determined on a consistent basis, as an average of the opening and quarterly period end values for the 12 month trailing period for each of the periods presented.

Outlook

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

2022 CAPITAL BUDGET

On January 11, 2022, the Company announced its 2022 base capital budget targeted at approximately $3,645 million. The budget also includes incremental strategic growth capital of approximately $700 million that targets to add future production and capacity in the Company's long life low decline thermal in situ and Oil Sands Mining and Upgrading assets.

The 2022 capital budget constitutes forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Other

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flows from operating activities and net earnings due to changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2021, excluding mark-to-market gains (losses) on risk management activities and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flows from Operating Activities ($ millions)	**Cash flows from Operating Activities** (per common share, basic)	**Net earnings (loss)** ($ millions)	**Net earnings (loss)** (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl				
Excluding financial derivatives	$ 311	$ 0.26	$ 311	$ 0.26
Including financial derivatives	$ 310	$ 0.26	$ 310	$ 0.26
Natural gas – AECO C$0.10/Mcf				
Excluding financial derivatives	$ 31	$ 0.03	$ 31	$ 0.03
Including financial derivatives	$ 27	$ 0.02	$ 27	$ 0.02
Volume changes				
Crude oil – 10,000 bbl/d	$ 170	$ 0.14	$ 144	$ 0.12
Natural gas – 10 MMcf/d	$ 10	$ 0.01	$ 5	$ —
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 268	$ 0.23	$ 142	$ 0.12
Interest rate change – 1%	$ 13	$ 0.01	$ 13	$ 0.01

(1) For details of financial instruments in place, refer to note 19 to the Company's audited consolidated financial statements as at December 31, 2021.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2021	2020	2019
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	**478,736**	**478,314**	**454,888**	**478,738**	**472,621**	460,443	405,970
North America – Oil Sands Mining and Upgrading [1]	**468,803**	**361,707**	**468,126**	**493,406**	**448,133**	417,351	395,133
North Sea	**19,959**	**16,458**	**16,294**	**17,860**	**17,633**	23,142	27,919
Offshore Africa	**11,854**	**16,239**	**13,531**	**14,421**	**14,017**	17,022	21,371
Total	**979,352**	**872,718**	**952,839**	**1,004,425**	**952,404**	917,958	850,393
Natural gas (MMcf/d) [2]							
North America	**1,585**	**1,594**	**1,698**	**1,841**	**1,680**	1,450	1,443
North Sea	**4**	**4**	**2**	**3**	**3**	12	24
Offshore Africa	**9**	**16**	**8**	**13**	**12**	15	24
Total	**1,598**	**1,614**	**1,708**	**1,857**	**1,695**	1,477	1,491
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	**742,871**	**743,923**	**737,902**	**785,476**	**752,620**	702,168	646,443
North America – Oil Sands Mining and Upgrading [1]	**468,803**	**361,707**	**468,126**	**493,406**	**448,133**	417,351	395,133
North Sea	**20,574**	**17,143**	**16,694**	**18,441**	**18,203**	25,095	31,915
Offshore Africa	**13,455**	**18,966**	**14,781**	**16,577**	**15,950**	19,522	25,466
Total	**1,245,703**	**1,141,739**	**1,237,503**	**1,313,900**	**1,234,906**	1,164,136	1,098,957

(1) SCO production before royalties excludes SCO consumed internally as diesel.

(2) Natural gas production volumes approximate sales volumes.

PER UNIT RESULTS – EXPLORATION AND PRODUCTION

	Q1	Q2	Q3	Q4	2021	2020	2019
Crude oil and NGLs ($/bbl) [1]							
Realized price [2]	**$ 52.68**	**$ 61.20**	**$ 68.06**	**$ 72.81**	**$ 63.71**	$ 31.90	$ 55.08
Transportation [2]	**3.56**	**3.98**	**4.00**	**3.93**	**3.86**	3.85	3.48
Realized price, net of transportation [2]	**49.12**	**57.22**	**64.06**	**68.88**	**59.85**	28.05	51.60
Royalties [3]	**5.69**	**8.50**	**9.46**	**10.67**	**8.59**	2.59	6.08
Production expense [4]	**14.56**	**13.75**	**14.78**	**15.70**	**14.71**	12.42	13.81
Netback [2]	**$ 28.87**	**$ 34.97**	**$ 39.82**	**$ 42.51**	**$ 36.55**	$ 13.04	$ 31.71
Natural gas ($/Mcf) [1]							
Realized price [5]	**$ 3.42**	**$ 3.17**	**$ 4.13**	**$ 5.35**	**$ 4.07**	$ 2.40	$ 2.34
Transportation [6]	**0.46**	**0.48**	**0.44**	**0.42**	**0.45**	0.43	0.42
Realized price, net of transportation	**2.96**	**2.69**	**3.69**	**4.93**	**3.62**	1.97	1.92
Royalties [3]	**0.16**	**0.12**	**0.22**	**0.35**	**0.22**	0.08	0.08
Production expense [4]	**1.27**	**1.19**	**1.17**	**1.12**	**1.18**	1.18	1.22
Netback [2]	**$ 1.53**	**$ 1.38**	**$ 2.30**	**$ 3.46**	**$ 2.22**	$ 0.71	$ 0.62
Barrels of oil equivalent ($/BOE) [1]							
Realized price [2]	**$ 41.80**	**$ 46.40**	**$ 52.09**	**$ 57.72**	**$ 49.67**	$ 26.15	$ 40.50
Transportation [2]	**3.29**	**3.58**	**3.50**	**3.40**	**3.44**	3.44	3.14
Realized price, net of transportation [2]	**38.51**	**42.82**	**48.59**	**54.32**	**46.23**	22.71	37.36
Royalties [3]	**4.10**	**5.77**	**6.45**	**7.48**	**5.98**	1.89	4.09
Production expense [4]	**12.20**	**11.42**	**11.91**	**12.33**	**11.98**	10.67	11.49
Netback [2]	**$ 22.21**	**$ 25.63**	**$ 30.23**	**$ 34.51**	**$ 28.27**	$ 10.15	$ 21.78

(1) For crude oil and NGLs and BOE sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A. For natural gas sales volumes, refer to the "Daily Production, before royalties" section of this MD&A.

(2) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(3) Calculated as royalties divided by respective sales volumes.

(4) Calculated as production expense divided by respective sales volumes.

(5) Calculated as natural gas sales divided by natural gas sales volumes.

(6) Calculated as natural gas transportation expense divided by natural gas sales volumes.

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING

	Q1	Q2	Q3	Q4	2021	2020	2019
Crude oil and NGLs ($/bbl) [1]							
Realized SCO sales price [2]	**$ 64.60**	**$ 76.19**	**$ 81.54**	**$ 88.48**	**$ 77.95**	$ 43.98	$ 70.18
Bitumen royalties [3]	**2.88**	**5.92**	**8.21**	**9.16**	**6.62**	0.51	3.31
Transportation [2]	**1.10**	**1.26**	**1.14**	**1.33**	**1.21**	1.23	1.29
Production costs [4]	**19.82**	**25.46**	**19.86**	**19.55**	**20.91**	20.46	22.56
Netback [2]	**$ 40.80**	**$ 43.55**	**$ 52.33**	**$ 58.44**	**$ 49.21**	$ 21.78	$ 43.02

(1) For SCO sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(2) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(3) Calculated as royalties divided by sales volumes.

(4) Calculated as production costs divided by sales volumes.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2021	2020
TSX – C$						
Trading volume (thousands)	**439,840**	**401,283**	**364,136**	**363,613**	**1,568,872**	1,866,414
Share Price ($/share)						
High	**$ 41.05**	**$ 46.36**	**$ 46.99**	**$ 55.59**	**$ 55.59**	$ 42.57
Low	**$ 28.67**	**$ 36.23**	**$ 37.82**	**$ 46.06**	**$ 28.67**	$ 9.80
Close	**$ 38.85**	**$ 45.00**	**$ 46.31**	**$ 53.45**	**$ 53.45**	$ 30.59
Market capitalization as at December 31 ($ millions)					**$ 62,449**	$ 36,214
Shares outstanding (thousands)					**1,168,369**	1,183,866
NYSE – US$						
Trading volume (thousands)	**243,664**	**177,553**	**188,674**	**185,714**	**795,605**	1,058,121
Share Price ($/share)						
High	**$ 32.64**	**$ 38.10**	**$ 37.39**	**$ 44.33**	**$ 44.33**	$ 32.79
Low	**$ 22.40**	**$ 28.86**	**$ 29.53**	**$ 36.37**	**$ 22.40**	$ 6.71
Close	**$ 30.87**	**$ 36.28**	**$ 36.54**	**$ 42.25**	**$ 42.25**	$ 24.05
Market capitalization as at December 31 ($ millions)					**$ 49,364**	$ 28,472
Shares outstanding (thousands)					**1,168,369**	1,183,866

ADDITIONAL DISCLOSURE

CERTIFICATIONS

The required disclosure is included in Exhibits 31.1, 31.2, 32.1 and 32.2 to this Annual Report on Form 40-F.

DISCLOSURE CONTROLS AND PROCEDURES

As of the end of the registrant's fiscal year ended December 31, 2021, an evaluation of the effectiveness of Canadian Natural's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), was carried out by Canadian Natural's management with the participation of Canadian Natural's principal executive officer and principal financial officer. Based upon the evaluation, Canadian Natural's principal executive officer and principal financial officer have concluded that as of the end of the fiscal year, Canadian Natural's disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and (ii) accumulated and communicated to Canadian Natural's management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

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

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The required disclosure is included in the "Management's Assessment of Internal Control Over Financial Reporting" that accompanies Canadian Natural's audited consolidated financial statements for the fiscal year ended December 31, 2021, filed as part of this Annual Report on Form 40-F.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

The required disclosure is included in the "Report of Independent Registered Public Accounting Firm" that accompanies Canadian Natural's audited consolidated financial statements for the fiscal year ended December 31, 2021, filed as part of this Annual Report on Form 40-F.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

During the fiscal year ended December 31, 2021, there were no changes in Canadian Natural's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, Canadian Natural's internal control over financial reporting.

NOTICES PURSUANT TO REGULATION BTR

None.

AUDIT COMMITTEE FINANCIAL EXPERT

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

CODE OF ETHICS

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

Any waivers of or amendments to the Code of Ethics must be approved by the Board of Directors and will be appropriately disclosed. In the past fiscal year, there have not been any waivers, including implicit waivers, from any provisions of the Code of Ethics.

The Code of Ethics is available through the System for Electronic Document and Analysis and Retrieval (SEDAR) at www.sedar.com. Canadian Natural hereby undertakes to provide to any person, without charge and upon request, a copy of its Code of Ethics. Requests for copies can also be made by contacting: Paul M. Mendes, Vice President, Legal, General Counsel and Corporate Secretary, Canadian Natural Resources Limited, 2100-855 2nd Street, S.W., Calgary, Alberta, Canada T2P 4J8.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

PricewaterhouseCoopers LLP (“PwC”), Calgary, Alberta, Canada (PCAOB ID 271), has been the auditor of Canadian Natural since 1973. The aggregate amounts billed by PwC for each of the last two fiscal years for audit fees, audit-related fees, tax fees and all other fees, excluding expenses, are set forth below.

AUDIT FEES

The aggregate fees billed for each of the last two fiscal years of Canadian Natural ended December 31, 2021 and December 31, 2020, for professional services rendered by PwC for the audit of its internal controls and annual consolidated financial statements in connection with statutory and regulatory filings or engagements for those fiscal years, unaudited reviews of the first, second and third quarters of its interim consolidated financial statements and audits of certain of Canadian Natural’s subsidiary companies’ annual financial statements were $2,310,000 for 2021 and were $2,207,000 for 2020.

Audit-Related Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ended December 31, 2021 and December 31, 2020, for audit-related services by PwC including pension assets and Crown Royalty Statements were $463,000 for 2021 and were $412,000 for 2020. Canadian Natural’s Audit Committee approved all of these audit-related services.

Tax Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ended December 31, 2021 and December 31, 2020, for professional services rendered by PwC for tax services related to expatriate personal tax compliance and other corporate tax return matters were $305,000 for 2021 and were $258,000 for 2020. Canadian Natural’s Audit Committee approved all of these tax-related services.

All Other Fees

The aggregate fees billed for each of the last two fiscal years of Canadian Natural, ended December 31, 2021 and December 31, 2020 for other services were $17,000 for 2021 and were $12,000 for 2020, related to expatriate visa application assistance and to accessing resource materials through PwC’s accounting literature library. Canadian Natural’s Audit Committee approved all of the noted services.

Audit Committee Pre-Approval Policies and Procedures

The Audit Committee’s duties and responsibilities include the review and approval of fees to be paid to the independent auditors, scope and timing of the audit and other related services rendered by the independent auditors. The Audit Committee also reviews and approves the independent auditor’s annual audit plan, including scope, staffing, locations and reliance upon management and internal audit department prior to the commencement of the audit and reviews and approves proposed non-audit services to be provided by the independent auditors, except those non-audit services prohibited by legislation. Canadian Natural did not rely on the de minimis exemption provided by paragraph (c)(7)(i)(c) of Rule 2.01 of Regulation S-X in 2020.

OFF BALANCE SHEET ARRANGEMENTS

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

DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The required disclosure is included under the ”Commitments and Contingencies" section of the Company's annual MD&A for the year ended December 31, 2021, dated March 2, 2022.

IDENTIFICATION OF THE AUDIT COMMITTEE

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

MINE SAFETY DISCLOSURE

Not Applicable.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

Undertaking

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

Consent to Service of Process

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

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

SIGNATURES

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

Dated this 23rd day of March, 2022.

CANADIAN NATURAL RESOURCES LIMITED

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

Documents filed as part of this report:

EXHIBIT INDEX

Exhibit No.	Description
23.1	Consent of Independent Registered Public Accounting Firm.
23.2	Consent of Sproule Associates Limited, Independent Petroleum Engineering Consultants.
23.3	Consent of Sproule International Limited, Independent Petroleum Engineering Consultants.
23.4	Consent of GLJ Ltd., Independent Petroleum Engineering Consultants.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 .
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 .
32.1	Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
32.2	Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
99.1	Supplementary Oil & Gas Information (Unaudited) for the fiscal year ended December 31, 2021.
101	Interactive data files with respect to the consolidated financial statements for the fiscal year ended December 31, 2021.

EXHIBIT 23.1



Consent of Independent Registered Public Accounting Firm

We hereby consent to the inclusion in this Annual Report on Form 40-F for the year ended December 31, 2021 of Canadian Natural Resources Limited, of our report dated March 2, 2022, relating to the consolidated financial statements, and the effectiveness of internal control over financial reporting, which appears in this Annual Report.

We also consent to the incorporation by reference in the Registration Statement on Form F-10 (SEC file number 333-258127) of Canadian Natural Resources Limited of our report dated March 2, 2022 referred to above. We also consent to reference to us under the heading “Interests of Experts,” which appears in the Annual Information Form included in this Annual Report on Form 40-F, which is incorporated by reference in such registration statement.

SIGNED "PricewaterhouseCoopers LLP"

Chartered Professional Accountants

Calgary, Canada
March 23, 2022

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

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

EXHIBIT 23.2

Sproule

LETTER OF CONSENT

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

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

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

(i) Annual Report on Form 40-F for the year ended December 31, 2021 and

(ii) Registration Statement on Form F-10 (File No. 333-258127) filed with the Securities and Exchange Commission.

Sincerely,
SPROULE ASSOCIATES LIMITED

SIGNED “Steven J. Golko”

Steven J. Golko, P.Eng.
Senior Vice President

Calgary, Alberta, Canada

March 23, 2022

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

EXHIBIT 23.3

Sproule

LETTER OF CONSENT

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

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

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

(i) Annual Report on Form 40-F for the year ended December 31, 2021 and

(ii) Registration Statement on Form F-10 (File No. 333-258127) filed with the Securities and Exchange Commission.

Sincerely,
SPROULE INTERNATIONAL LIMITED

SIGNED “Scott W. Pennell”

Scott W. Pennell, P.Eng.
Chief Operating Officer

Calgary, Alberta, Canada
March 23, 2022

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

EXHIBIT 23.4

LETTER OF CONSENT

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

Re: Consent of Independent Petroleum Consultants

To Whom It May Concern:

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

(i) Annual Report on Form 40-F for the year ended December 31, 2021 and

(ii) Registration Statement on Form F-10 (File No. 333-258127) filed with the Securities and Exchange Commission.

Yours truly,
GLJ LTD.

"Originally Signed By"

Tim R. Freeborn, P.Eng.
Vice President and Chief Financial Officer

Calgary, Alberta, Canada
March 23, 2022

EXHIBIT 31.1

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

CERTIFICATION

I, Tim S. McKay, certify that:

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

Dated this 23rd day of March, 2022.

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

EXHIBIT 31.2

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

CERTIFICATION

I, Mark A. Stainthorpe, certify that:

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

Dated this 23rd day of March, 2022.

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

EXHIBIT 32.1

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

In connection with the Annual Report of Canadian Natural Resources Limited (the "Company") on Form 40-F for the fiscal year ending December 31, 2021 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Tim S. McKay, certify pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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

DATED this 23rd day of March, 2022.

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

EXHIBIT 32.2

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

In connection with the Annual Report of Canadian Natural Resources Limited (the "Company") on Form 40-F for the fiscal year ending December 31, 2021 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Mark A. Stainthorpe, certify pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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

DATED this 23rd day of March, 2022.

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

Supplementary Oil & Gas Information for the Fiscal Year Ended December 31, 2021 (Unaudited)

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

For the years ended December 31, 2021, 2020, 2019 and 2018 the Company filed its reserves information under National Instrument 51-101 – "Standards of Disclosure of Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada.

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

For the purposes of determining proved crude oil and natural gas reserves for SEC requirements as at December 31, 2021, 2020, 2019 and 2018 the Company used the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The Company has used the following 12-month average benchmark prices to determine its 2021 and 2020 reserves for SEC requirements.

	Crude Oil and NGLs						Natural Gas		
	WTI	**WCS**	**Canadian Light Sweet**	**Cromer LSB**	**Brent**	**Edmonton C5+**	**Henry Hub**	**AECO**	**BC Westcoast Station 2**
	(US$/bbl)	(C$/bbl)	(C$/bbl)	(C$/bbl)	(US$/bbl)	(C$/bbl)	(US$/MMBtu)	(C$/MMBtu)	(C$/MMBtu)
2021:									
	66.34	**67.68**	**77.87**	**78.17**	**68.92**	**83.05**	**3.68**	**3.39**	**2.90**
2020:									
	39.77	34.84	45.02	45.55	43.43	50.41	2.16	2.17	2.10

A foreign exchange rate of US$ 0.7972/C$1.00 was used in the 2021 evaluation (2020 - US$ 0.7462/C$1.00), determined on the same basis as the 12-month average price.

Net Proved Crude Oil and Natural Gas Reserves

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

- For the years ended December 31, 2021, 2020, 2019 and 2018, the reports by GLJ Ltd. covered 100% of the Company's SCO reserves. With the inclusion of non-traditional resources within the definition of "oil and gas producing activities" in the SEC's modernization of oil and gas reporting rules, effective January 1, 2010 these reserves volumes are included within the Company's crude oil and natural gas reserves totals.
- For the years ended December 31, 2021, 2020, 2019 and 2018, the reports by Sproule Associates Limited and Sproule International Limited covered 100% of the Company's crude oil, bitumen, natural gas and NGLs reserves.

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

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

The following tables summarize the Company's proved and proved developed crude oil and natural gas reserves, net of royalties, as at December 31, 2021, 2020, 2019 and 2018:

	North America						
Crude Oil and NGLs (MMbbl)[1]	**Synthetic Crude Oil**	**Bitumen**[2]	**Crude Oil & NGLs**	**North America Total**	**North Sea**	**Offshore Africa**	**Total**
Net Proved Reserves							
Reserves, December 31, 2018	5,661	1,469	604	7,734	114	71	7,919
Extensions and discoveries	334	18	12	364	—	—	364
Improved recovery	—	169	12	181	—	—	181
Purchases of reserves in place	—	666	2	668	—	—	668
Sales of reserves in place	—	—	—	—	—	—	—
Production	(137)	(81)	(49)	(267)	(10)	(7)	(285)
Economic revisions due to prices[3]	(288)	3	—	(285)	(1)	1	(285)
Revisions of prior estimates	(17)	(27)	17	(28)	3	6	(19)
Reserves, December 31, 2019	5,554	2,216	598	8,368	105	70	8,544
Extensions and discoveries	708	8	10	726	—	—	726
Improved recovery	—	49	9	58	—	—	58
Purchases of reserves in place	—	—	28	28	—	—	28
Sales of reserves in place	—	—	—	—	—	—	—
Production	(151)	(109)	(45)	(305)	(8)	(6)	(320)
Economic revisions due to prices[4]	701	207	(94)	814	(12)	3	805
Revisions of prior estimates	36	41	20	97	3	4	103
Reserves, December 31, 2020	6,847	2,413	525	9,785	87	71	9,943
Extensions and discoveries	**—**	**101**	**14**	**115**	**—**	**—**	**115**
Improved recovery	**—**	**19**	**14**	**33**	**—**	**—**	**33**
Purchases of reserves in place	**—**	**—**	**52**	**52**	**—**	**—**	**52**
Sales of reserves in place	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Production	**(150)**	**(103)**	**(45)**	**(297)**	**(6)**	**(5)**	**(309)**
Economic revisions due to prices[5]	**(927)**	**(296)**	**108**	**(1,115)**	**1**	**(4)**	**(1,118)**
Revisions of prior estimates	**174**	**155**	**40**	**369**	**(3)**	**2**	**368**
Reserves, December 31, 2021	**5,944**	**2,289**	**708**	**8,941**	**79**	**64**	**9,083**
Net proved developed reserves							
December 31, 2018	5,661	461	378	6,500	37	34	6,571
December 31, 2019	5,452	661	354	6,466	38	39	6,543
December 31, 2020	6,770	628	285	7,682	32	37	7,751
December 31, 2021	**5,929**	**584**	**370**	**6,883**	**39**	**38**	**6,960**

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

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

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

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

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

2021 total proved Crude Oil and NGLs reserves decreased by 860 MMbbl:

- Extensions and discoveries: Increase of 115 MMbbl primarily due to extension drilling/future offset additions at various Bitumen properties.
- Improved recovery: Increase of 33 MMbbl primarily due to increased recovery of thermal Bitumen at Jackfish and Kirby properties and infill drilling/future offset additions at various Crude Oil and natural gas (NGLs) properties.
- Purchases of reserves in place: Increase of 52 MMbbl primarily due to natural gas (NGLs) acquisitions in northeast British Columbia.
- Production: Decrease of 309 MMbbl.
- Economic revisions due to prices: Decrease of 1,118 MMbbl primarily at Oil Sands Mining and Upgrading (SCO) and thermal Bitumen properties due to higher bitumen pricing resulting in higher royalties and lower net reserves.
- Revisions of prior estimates: Increase of 368 MMbbl primarily due to transfers from beyond the 50-year reserves life cutoff at Oil Sands Mining and Upgrading (SCO) and improved performance at various North America and Offshore Africa Crude Oil, Bitumen and natural gas (NGLs) properties.

2020 total proved Crude Oil and NGLs reserves increased by 1,400 MMbbl:

- Extensions and discoveries: Increase of 726 MMbbl primarily due to the pit extension at Oil Sands Mining and Upgrading (SCO) and extension drilling/future offset additions at various Bitumen, Crude Oil and natural gas (NGLs) properties.
- Improved recovery: Increase of 58 MMbbl primarily due to increased steamflood recovery of Bitumen at Primrose and infill drilling/future offset additions at various Bitumen, Crude Oil and natural gas (NGLs) properties.
- Purchases of reserves in place: Increase of 28 MMbbl primarily of NGLs from the acquisition of Painted Pony Energy Ltd.
- Production: Decrease of 320 MMbbl.
- Economic revisions due to prices: Increase of 805 MMbbl primarily at Oil Sands Mining and Upgrading (SCO) and thermal Bitumen properties due to lower bitumen pricing resulting in lower royalties and higher net reserves, partially offset by uneconomic reserves at several North America Bitumen (primary heavy crude oil) and Crude Oil properties.
- Revisions of prior estimates: Increase of 103 MMbbl primarily due to improved mine performance and mine model changes at Oil Sands Mining and Upgrading (SCO) and improved performance at North America, North Sea and Offshore Africa Crude Oil, Bitumen and various natural gas (NGLs) properties.

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

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

Natural Gas (Bcf)[1]	North America	North Sea	Offshore Africa	Total
Net Proved Reserves				
Reserves, December 31, 2018	4,306	27	21	4,354
Extensions and discoveries	106	—	—	106
Improved recovery	202	—	—	202
Purchases of reserves in place	34	—	—	34
Sales of reserves in place	—	—	—	—
Production	(511)	(9)	(8)	(528)
Economic revisions due to prices	246	—	2	248
Revisions of prior estimates	346	(2)	23	367
Reserves, December 31, 2019	4,728	16	38	4,782
Extensions and discoveries	173	—	—	173
Improved recovery	159	—	—	159
Purchases of reserves in place	2,614	—	—	2,615
Sales of reserves in place	(4)	—	—	(4)
Production	(515)	(4)	(5)	(524)
Economic revisions due to prices	97	—	4	100
Revisions of prior estimates	402	—	(3)	399
Reserves, December 31, 2020	7,655	12	34	7,701
Extensions and discoveries	**545**	**—**	**—**	**545**
Improved recovery	**161**	**—**	**—**	**161**
Purchases of reserves in place	**1,654**	**—**	**—**	**1,654**
Sales of reserves in place	**(1)**	**—**	**—**	**(1)**
Production	**(581)**	**(1)**	**(4)**	**(587)**
Economic revisions due to prices	**712**	**—**	**(4)**	**708**
Revisions of prior estimates	**1,139**	**(3)**	**—**	**1,136**
Reserves, December 31, 2021	**11,285**	**8**	**25**	**11,318**
Net proved developed reserves				
December 31, 2018	2,382	23	12	2,417
December 31, 2019	2,342	11	28	2,381
December 31, 2020	3,116	6	22	3,144
December 31, 2021	**4,469**	**3**	**20**	**4,492**

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

2021 total proved Natural Gas reserves increased by 3,617 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 545 Bcf primarily due to extension drilling/future offsets additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 161 Bcf primarily due to infill drilling/future offsets additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 1,654 Bcf primarily due to the Storm Resources Ltd. and other acquisitions in northeast British Columbia.
- Sales of reserves in place: Decrease of 1 Bcf from Natural Gas properties in North America.
- Production: Decrease of 587 Bcf.
- Economic revisions due to prices: Increase of 708 Bcf primarily due to increased Natural Gas price in North America.
- Revisions of prior estimates: Increase of 1,136 Bcf primarily due to overall positive revisions in several North American core areas as a result of increased performance and category transfers from probable to proved.

2020 total proved Natural Gas reserves increased by 2,919 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 173 Bcf primarily due to extension drilling/future offset additions in the Montney and other unconventional formations of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 159 Bcf primarily due to infill drilling/future offset additions in the Montney and other unconventional formations of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 2,615 Bcf primarily due to the acquisition of Painted Pony Energy Ltd.
- Sales of reserves in place: Decrease of 4 Bcf from Natural Gas properties in North America.
- Production: Decrease of 524 Bcf.
- Economic revisions due to prices: Increase of 100 Bcf primarily due to increased Natural Gas price in North America.
- Revisions of prior estimates: Increase of 399 Bcf primarily due to overall positive revisions in several North America core areas as a result of increased recovery and category transfers from probable to proved, partially offset by removal of future extension and infill undeveloped reserves in North America properties due to revised Company development plans.

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

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

Capitalized Costs Related to Crude Oil and Natural Gas Activities

(millions of Canadian dollars)	2021 North America	North Sea	Offshore Africa	Total
Proved properties	$ 124,690	$ 7,438	$ 3,980	$ 136,108
Unproved properties	2,159	—	91	2,250
	126,849	7,438	4,071	138,358
Less: accumulated depletion and depreciation	(61,231)	(5,951)	(2,923)	(70,105)
Net capitalized costs	$ 65,618	$ 1,487	$ 1,148	$ 68,253

(millions of Canadian dollars)	2020 North America	North Sea	Offshore Africa	Total
Proved properties	$ 119,707	$ 7,283	$ 3,963	$ 130,953
Unproved properties	2,353	—	83	2,436
	122,060	7,283	4,046	133,389
Less: accumulated depletion and depreciation	(56,930)	(5,853)	(2,822)	(65,605)
Net capitalized costs	$ 65,130	$ 1,430	$ 1,224	$ 67,784

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

Costs Incurred in Crude Oil and Natural Gas Activities

(millions of Canadian dollars)	2021 North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 1,371	$ —	$ —	$ 1,371
Unproved	26	—	—	26
Exploration	4	—	8	12
Development	4,301	208	48	4,557
Costs incurred	$ 5,702	$ 208	$ 56	$ 5,966

(millions of Canadian dollars)	2020 North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 750	$ —	$ —	$ 750
Unproved	15	—	—	15
Exploration	22	—	15	37
Development	2,338	104	94	2,536
Costs incurred	$ 3,125	$ 104	$ 109	$ 3,338

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

Results of Operations from Crude Oil and Natural Gas Producing Activities

The Company's results of operations from crude oil and natural gas producing activities for the years ended December 31, 2021, 2020 and 2019 are summarized in the following tables:

	2021			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	**$ 23,111**	**$ 611**	**$ 438**	**$ 24,160**
Production	**(6,377)**	**(383)**	**(91)**	**(6,851)**
Transportation	**(1,176)**	**(7)**	**(1)**	**(1,184)**
Depletion, depreciation and amortization	**(5,407)**	**(160)**	**(142)**	**(5,709)**
Asset retirement obligation accretion	**(158)**	**(21)**	**(6)**	**(185)**
Petroleum revenue tax	**—**	**33**	**—**	**33**
Income tax	**(2,317)**	**(29)**	**(50)**	**(2,396)**
Results of operations	**$ 7,676**	**$ 44**	**$ 148**	**$ 7,868**

	2020			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	$ 12,520	$ 432	$ 354	$ 13,306
Production	(5,624)	(321)	(103)	(6,048)
Transportation	(1,258)	(15)	(1)	(1,274)
Depletion, depreciation and amortization	(5,564)	(277)	(190)	(6,031)
Asset retirement obligation accretion	(169)	(30)	(6)	(205)
Petroleum revenue tax	—	31	—	31
Income tax	23	72	(13)	82
Results of operations	$ (72)	$ (108)	$ 41	$ (139)

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

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

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

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

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

	2021			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Future cash inflows	**$ 679,123**	**$ 7,791**	**$ 5,581**	**$ 692,495**
Future production costs	**(238,144)**	**(4,074)**	**(1,818)**	**(244,036)**
Future development costs and asset retirement obligations	**(77,375)**	**(1,857)**	**(1,142)**	**(80,374)**
Future income taxes	**(81,860)**	**(719)**	**(565)**	**(83,144)**
Future net cash flows	**281,744**	**1,141**	**2,056**	**284,941**
10% annual discount for timing of future cash flows	**(201,227)**	**(142)**	**(788)**	**(202,157)**
Standardized measure of future net cash flows	**$ 80,517**	**$ 999**	**$ 1,268**	**$ 82,784**

	2020			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Future cash inflows	$ 404,193	$ 5,873	$ 4,172	$ 414,238
Future production costs	(203,599)	(3,259)	(1,746)	(208,604)
Future development costs and asset retirement obligations	(72,935)	(2,130)	(1,032)	(76,097)
Future income taxes	(27,178)	(141)	(217)	(27,536)
Future net cash flows	100,481	343	1,177	102,001
10% annual discount for timing of future cash flows [(1)]	(74,395)	278	(373)	(74,490)
Standardized measure of future net cash flows	$ 26,086	$ 621	$ 804	$ 27,511

(1) Includes the impact of abandonment expenditures timing.

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

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

(millions of Canadian dollars)	**2021**	2020	2019
Sales of crude oil and natural gas produced, net of production costs	**$ (16,149)**	$ (6,127)	$ (11,807)
Net changes in sales prices and production costs	**74,558**	(46,055)	(3,515)
Extensions, discoveries and improved recovery	**2,948**	626	5,883
Changes in estimated future development costs	**(2,773)**	(153)	(1,889)
Purchases of proved reserves in place	**4,010**	947	7,418
Sales of proved reserves in place	**(1)**	(1)	—
Revisions of previous reserve estimates	**(186)**	5,295	(3,384)
Accretion of discount	**3,460**	7,718	8,062
Changes in production timing and other	**6,638**	(4,830)	447
Net change in income taxes	**(17,232)**	6,566	1,984
Net change	**55,273**	(36,014)	3,199
Balance - beginning of year	**27,511**	63,525	60,326
Balance - end of year	**$ 82,784**	$ 27,511	$ 63,525