Canadian Natural

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	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	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	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	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	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	**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	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
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	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
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	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	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	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
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	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
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	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	**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

($ millions)	North America Total Proved	North America Total Proved plus Probable	North Sea Total Proved	North Sea Total Proved plus Probable	Offshore Africa Total Proved	Offshore Africa Total Proved plus Probable	Total Company Total Proved	Total Company 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° API), low sulphur content Mixed Sweet Blend (MSW) crude oil at Edmonton, Alberta; reference price used in the preparation of light and medium crude oil and SCO reserves.
   - "Cromer LSB" refers to the price of light sour blend (35° API) physical crude oil at Cromer, Manitoba; reference price used in the preparation of light and medium crude oil in SE Saskatchewan and SW Manitoba reserves.
   - "Edmonton C5+" refers to pentanes plus at Edmonton, Alberta; reference price used in the preparation of NGLs reserves; also used in determining the diluent costs associated with primary heavy crude oil and bitumen (thermal oil) reserves.

- "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.

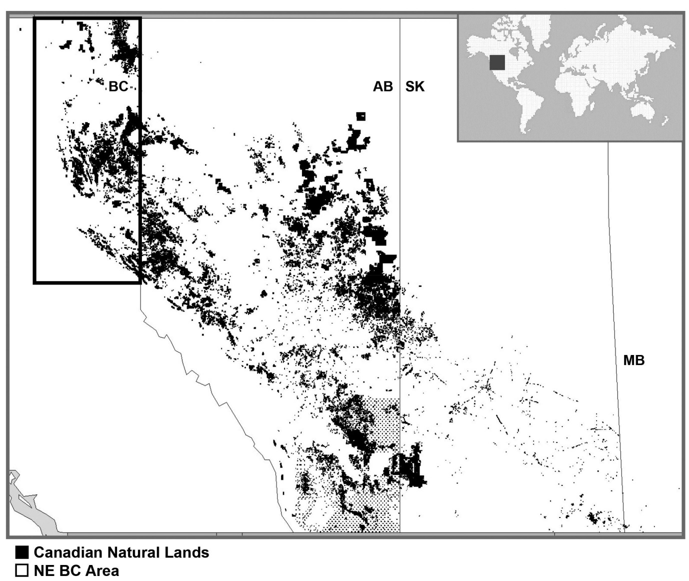
Other Oil and Gas Information

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



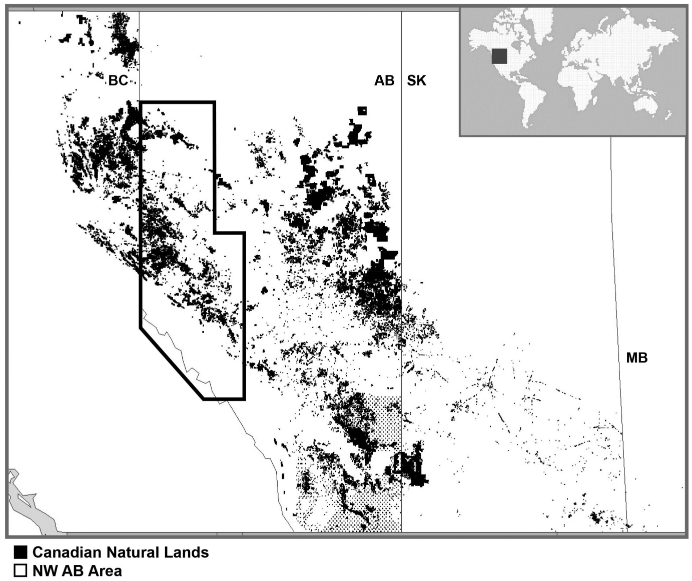
The northeast British Columbia region holds a significant portion of the Montney formation and provides exploration and development opportunities in combination with significant controlled infrastructure. The exploration strategy focuses on comprehensive evaluation through two dimensional seismic, three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

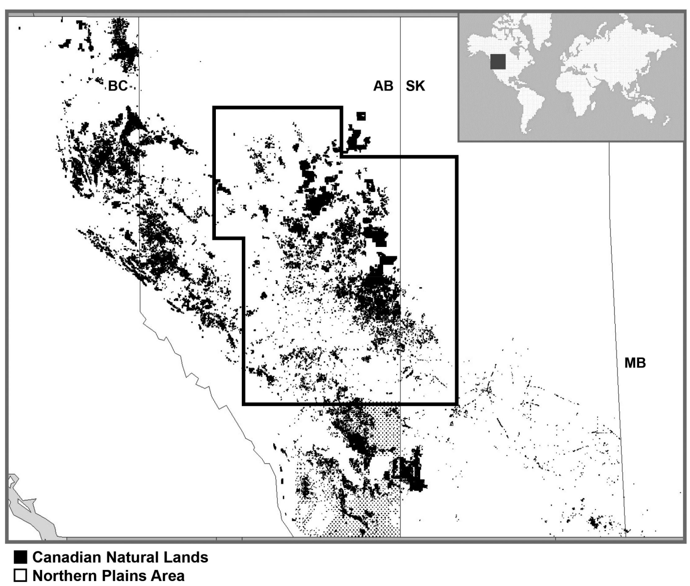
The southern portion of this region encompasses the Company's BC Foothills assets where natural gas is produced from the deep Mississippian and Triassic aged reservoirs in this highly structural area.

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.

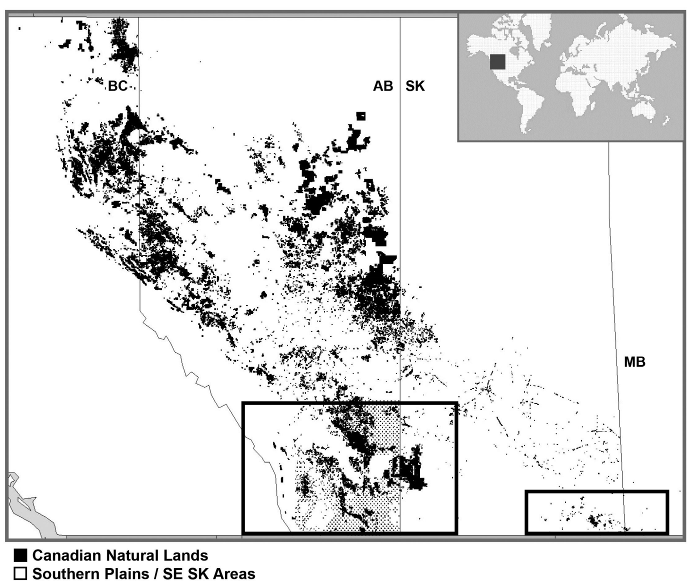
Included in the northern part of this region, approximately 200 miles north of Edmonton, Alberta are the Company's holdings at Pelican Lake. These assets produce Pelican Lake heavy crude oil from the Wabasca formation with gravities of 12°-17° API. Production expenses are low due to the absence of sand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

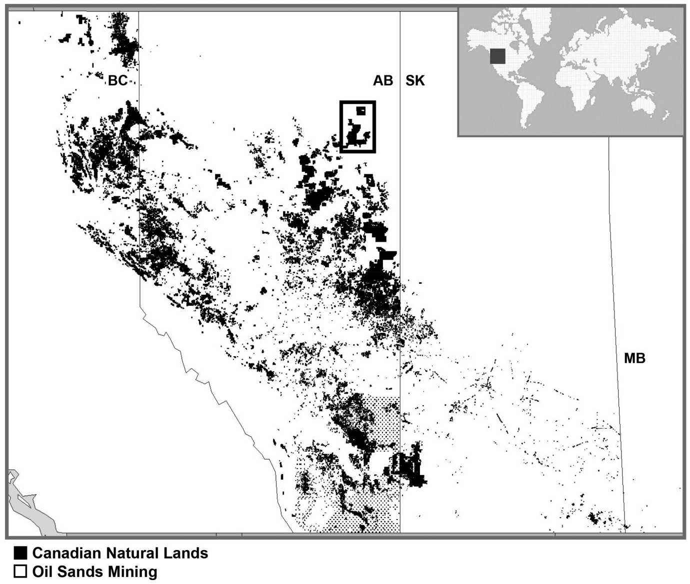


The Southern Plains region is principally located south of the Northern Plains region to the United States border and extending into western Saskatchewan.

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.

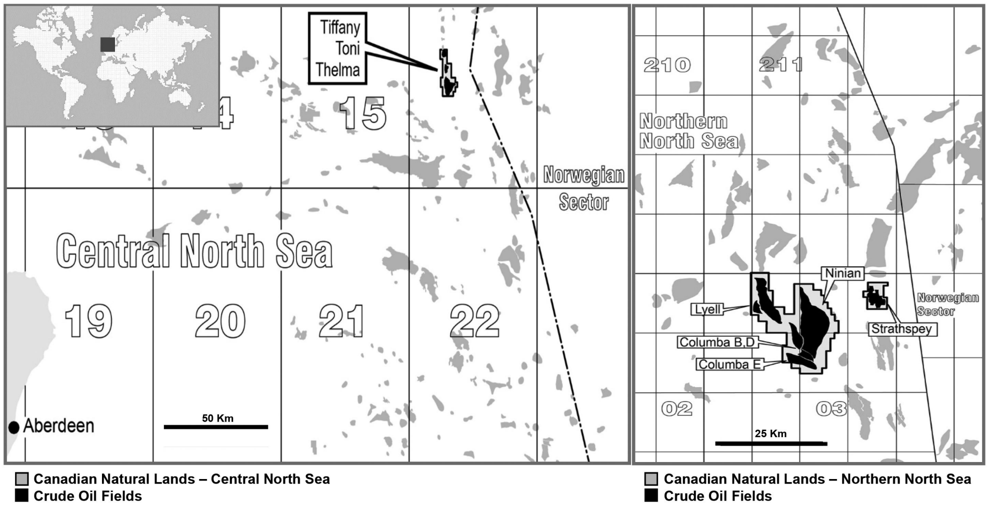
In 2018, the Company acquired the Joslyn oil sands project, adding to the Company's total oil sands mining and upgrading reserves. This incorporation of the Joslyn leases (now, Horizon South) to the mine plan will allow mining to continue south of the previously existing Horizon leases with opportunity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

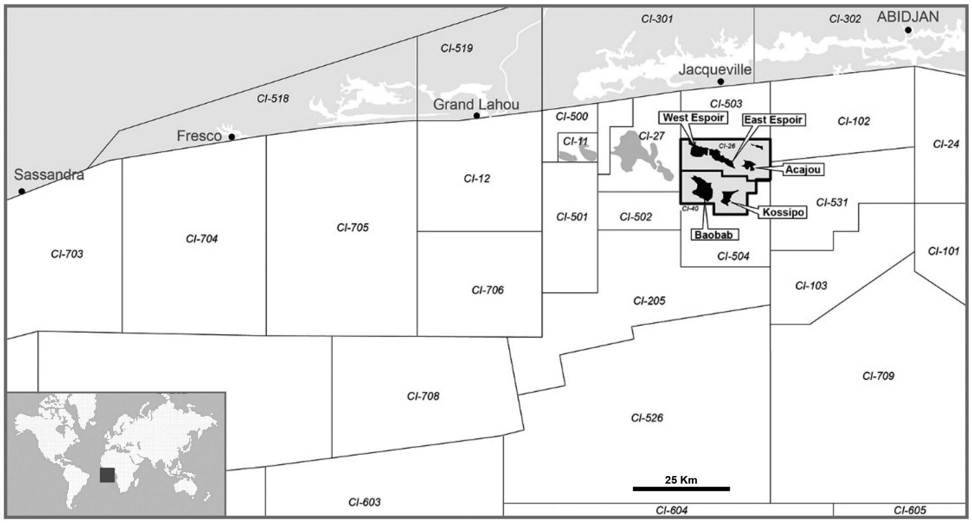
The Company receives tariff revenue from third parties for the processing of crude oil and natural gas through certain processing facilities.

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



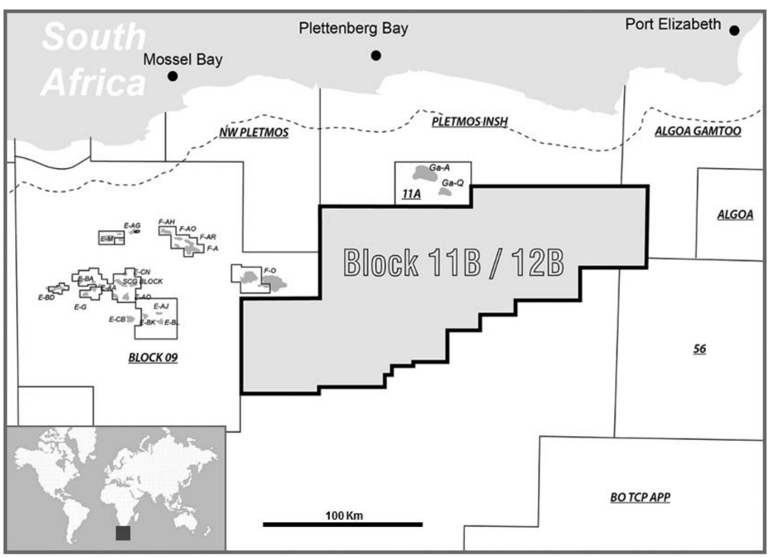
Canadian Natural Lands – Côte d'Ivoire
Crude Oil Fields

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



Canadian Natural Lands – 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**

	Q1	Q2	Q3	Q4	Year Ended
			2021		
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

Sproule International 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

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

Validation
Sproule Associates Limited
APEGA Permit #00417

Validation
Sproule International Limited
APEGA Permit #06151

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 "SCOTT W. PENNELL"
Scott W. Pennell, P.Eng.
Chief Operating Officer
March 2, 2022
RM APEGA ID 94501

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

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.