



**Canadian Natural**

**CANADIAN NATURAL RESOURCES LIMITED**

**MANAGEMENT'S DISCUSSION AND ANALYSIS**  
**FOR THE YEAR ENDED DECEMBER 31, 2022**

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**March 1, 2023**

# Management's Discussion and Analysis

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## Definitions and Abbreviations

<b>AECO</b>	Alberta natural gas reference location	<b>IFRS</b>	International Financial Reporting Standards
<b>AIF</b>	Annual Information Form	<b>LIBOR</b>	London Interbank Offered Rate
<b>AOSP</b>	Athabasca Oil Sands Project	<b>Mbbl</b>	thousand barrels
<b>API</b>	specific gravity measured in degrees on the American Petroleum Institute scale	<b>Mbbl/d</b>	thousand barrels per day
<b>ARO</b>	asset retirement obligations	<b>MBOE</b>	thousand barrels of oil equivalent
<b>bbl</b>	barrel	<b>MBOE/d</b>	thousand barrels of oil equivalent per day
<b>bbl/d</b>	barrels per day	<b>Mcf</b>	thousand cubic feet
<b>Bcf</b>	billion cubic feet	<b>Mcfe</b>	thousand cubic feet equivalent
<b>Bcf/d</b>	billion cubic feet per day	<b>Mcf/d</b>	thousand cubic feet per day
<b>Bitumen</b>	a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons that are too heavy or thick to flow at reservoir conditions, and recoverable at economic rates using thermal in situ recovery methods	<b>MMbbl</b>	million barrels
<b>BOE</b>	barrels of oil equivalent	<b>MMBOE</b>	million barrels of oil equivalent
<b>BOE/d</b>	barrels of oil equivalent per day	<b>MMBtu</b>	million British thermal units
<b>Brent</b>	Dated Brent	<b>MMcf</b>	million cubic feet
<b>C\$</b>	Canadian dollars	<b>MMcf/d</b>	million cubic feet per day
<b>CAGR</b>	compound annual growth rate	<b>NGLs</b>	natural gas liquids
<b>CAPEX</b>	capital expenditures	<b>NWRP</b>	North West Redwater Partnership
<b>CO<sub>2</sub></b>	carbon dioxide	<b>NYMEX</b>	New York Mercantile Exchange
<b>CO<sub>2</sub>e</b>	carbon dioxide equivalents	<b>NYSE</b>	New York Stock Exchange
<b>Crude oil</b>	includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil	<b>OPEC+</b>	Organization of the Petroleum Exporting Countries Plus
<b>CSS</b>	Cyclic Steam Stimulation	<b>PRT</b>	Petroleum Revenue Tax
<b>EOR</b>	Enhanced Oil Recovery	<b>SAGD</b>	Steam-Assisted Gravity Drainage
<b>E&amp;P</b>	Exploration and Production	<b>SCO</b>	synthetic crude oil
<b>FASB</b>	Financial Accounting Standards Board	<b>SEC</b>	United States Securities and Exchange Commission
<b>FPSO</b>	Floating Production, Storage and Offloading Vessel	<b>SOFR</b>	Secured Overnight Financing Rate
<b>GHG</b>	greenhouse gas	<b>Tcf</b>	trillion cubic feet
<b>GJ</b>	gigajoules	<b>TSX</b>	Toronto Stock Exchange
<b>GJ/d</b>	gigajoules per day	<b>UK</b>	United Kingdom
<b>Horizon</b>	Horizon Oil Sands	<b>US</b>	United States
<b>IASB</b>	International Accounting Standards Board	<b>US GAAP</b>	generally accepted accounting principles in the United States
<b>IBOR</b>	Interbank Offered Rate	<b>US\$</b>	United States dollars
		<b>WCS</b>	Western Canadian Select
		<b>WCS Heavy Differential</b>	WCS Heavy Differential from WTI
		<b>WTI</b>	West Texas Intermediate reference location at Cushing, Oklahoma

## Advisory

### SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, income tax expenses, and other targets provided throughout this Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including, without limitation, those in relation to: the Company's assets at Horizon, AOSP, the Primrose thermal oil projects, the Pelican Lake water and polymer flood projects, the Kirby Thermal Oil Sands Project, the Jackfish Thermal Oil Sands Project and the North West Redwater bitumen upgrader and refinery; construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, NGLs or SCO that the Company may be reliant upon to transport its products to market; the development and deployment of technology and technological innovations; the financial capacity of the Company to complete its growth projects and responsibly and sustainably grow in the long-term; and the impact of the Pathways Alliance ("Pathways") initiative and activities, government support for Pathways and the ability to achieve net zero emissions from oil production, also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and NGLs reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of effects of the novel coronavirus ("COVID-19") pandemic, the actions of OPEC+ and inflation) 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, 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 the mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities (including government mandated production curtailments); government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short, medium, and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

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

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

## **SPECIAL NOTE REGARDING NON-GAAP AND OTHER FINANCIAL MEASURES**

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

## **SPECIAL NOTE REGARDING CURRENCY, FINANCIAL INFORMATION, PRODUCTION AND RESERVES**

This MD&A should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2022. It should also be read in conjunction with the Company's MD&A for the three months and year ended December 31, 2022. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's consolidated financial statements and this MD&A have been prepared in accordance with IFRS as issued by the IASB.

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

The following discussion and analysis refers primarily to the Company's 2022 financial results compared to 2021 and 2020, unless otherwise indicated. In addition, this MD&A details the Company's targeted capital program for 2023. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its quarterly MD&A for the three months and year ended December 31, 2022, its Annual Information Form for the year ended December 31, 2022, and its audited consolidated financial statements for the year ended December 31, 2022, is available on SEDAR at [www.sedar.com](http://www.sedar.com), and on EDGAR at [www.sec.gov](http://www.sec.gov). Information on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated March 1, 2023.

## Objectives and Strategy

The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value <sup>(1)</sup> 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 endeavors to meet these objectives by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a balanced approach to growth and investments and focuses on creating long-term shareholder value. The Company allocates its capital by maintaining:

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

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

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

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

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

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

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

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

## Financial and Operational Highlights

(\$ millions, except per common share amounts)	2022		2021		2020	
Product sales <sup>(1)</sup>	\$	<b>49,530</b>	\$	32,854	\$	17,491
Crude oil and NGLs	\$	<b>43,009</b>	\$	29,256	\$	15,579
Natural gas	\$	<b>5,236</b>	\$	2,716	\$	1,478
Net earnings (loss)	\$	<b>10,937</b>	\$	7,664	\$	(435)
Per common share – basic	\$	<b>9.64</b>	\$	6.49	\$	(0.37)
– diluted	\$	<b>9.52</b>	\$	6.46	\$	(0.37)
Adjusted net earnings (loss) from operations <sup>(2)</sup>	\$	<b>12,863</b>	\$	7,420	\$	(756)
Per common share – basic <sup>(3)</sup>	\$	<b>11.33</b>	\$	6.28	\$	(0.64)
– diluted <sup>(3)</sup>	\$	<b>11.19</b>	\$	6.25	\$	(0.64)
Cash flows from operating activities	\$	<b>19,391</b>	\$	14,478	\$	4,714
Adjusted funds flow <sup>(2)</sup>	\$	<b>19,791</b>	\$	13,733	\$	5,200
Per common share – basic <sup>(3)</sup>	\$	<b>17.44</b>	\$	11.63	\$	4.40
– diluted <sup>(3)</sup>	\$	<b>17.22</b>	\$	11.57	\$	4.40
Dividends declared per common share <sup>(4)</sup>	\$	<b>4.60</b>	\$	2.00	\$	1.70
Total assets	\$	<b>76,142</b>	\$	76,665	\$	75,276
Total long-term liabilities	\$	<b>29,316</b>	\$	32,298	\$	37,818
Cash flows used in investing activities	\$	<b>4,987</b>	\$	3,703	\$	2,819
Net capital expenditures <sup>(2)</sup>	\$	<b>5,471</b>	\$	4,908	\$	3,206
Average realized price						
Crude oil and NGLs - Exploration and Production (\$/bbl) <sup>(3)</sup>	\$	<b>90.64</b>	\$	63.71	\$	31.90
Natural gas - Exploration and Production (\$/Mcf) <sup>(5)</sup>	\$	<b>6.55</b>	\$	4.07	\$	2.40
SCO - Oil Sands Mining and Upgrading (\$/bbl) <sup>(3)</sup>	\$	<b>117.69</b>	\$	77.95	\$	43.98
Daily production, before royalties (BOE/d)		<b>1,281,434</b>		1,234,906		1,164,136
Crude oil and NGLs (bbl/d)		<b>933,149</b>		952,404		917,958
Natural gas (MMcf/d) <sup>(6)</sup>		<b>2,090</b>		1,695		1,477

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

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

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

(4) On November 2, 2022, the Board of Directors approved a 13% increase in the quarterly dividend to \$0.85 per common share, from \$0.75 per common share. On August 3, 2022, the Board of Directors approved a special dividend of \$1.50 per common share. On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to \$0.75 per common share, from \$0.5875 per common share. On November 3, 2021, the Board of Directors approved a 25% increase in the quarterly dividend to \$0.5875 per common share, from \$0.47 per common share. On March 3, 2021, the Board of Directors approved an 11% increase in the quarterly dividend to \$0.47 per common share, from \$0.425 per common share. On March 4, 2020, the Board of Directors approved a 13% increase in the quarterly dividend to \$0.425 per common share, from \$0.375 per common share.

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

(6) Natural gas production volumes approximate sales volumes.

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

For 2022, the Company reported net earnings of \$10,937 million compared with \$7,664 million for 2021 (2020 – net loss of \$435 million). Net earnings for 2022 included non-operating items, net of tax, of \$1,926 million compared with \$244 million for 2021 (2020 – \$321 million) related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of realized foreign exchange on the settlement of the cross currency swap and repayment of US dollar debt securities, the gain on acquisitions, the (gain) loss from investments, a recoverability charge relating to the de-booking of reserves at the Ninian field in the North Sea, and government grant income under the provincial well-site rehabilitation programs. Excluding these items, adjusted net earnings from operations for 2022 were \$12,863 million compared with \$7,420 million for 2021 (2020 – adjusted net loss from operations of \$756 million).

The increase in net earnings and adjusted net earnings from operations for 2022 compared with 2021 primarily reflected:

- higher crude oil and NGLs netbacks<sup>(1)</sup> and crude oil sales volumes in the North America segment;
- higher natural gas netbacks and natural gas sales volumes in the Exploration and Production segments; and
- higher realized SCO sales price<sup>(1)</sup> in the Oil Sands Mining and Upgrading segment;

partially offset by:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment.

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

The impacts of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the gain on acquisitions, income from NWRP, and the (gain) loss from investments, also contributed to the movements in net earnings for 2022 from 2021. These items are discussed in detail in the relevant sections of this MD&A.

Prevailing regulatory and economic conditions in 2022 and the increasingly challenging commercial outlook in the United Kingdom, including the impact of higher natural gas and carbon costs, led the Company to assess the viability of its North Sea operations. Following a detailed review of its development plans, the Company determined that the Ninian field is no longer economic, de-booked associated crude oil reserves as at December 31, 2022, and is accelerating abandonment. As a result, the Company completed a recoverability assessment of its assets in the North Sea, and recognized a non-cash charge of \$651 million (after-tax) related to the Ninian field property, plant and equipment, comprised of a recoverability charge of \$1,620 million recognized in depletion, depreciation and amortization, net of deferred tax recoveries of \$969 million.

## CASH FLOWS FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW

Cash flows from operating activities for 2022 were \$19,391 million compared with \$14,478 million for 2021 (2020 – \$4,714 million). The fluctuations in cash flows from operating activities for 2022 from 2021 were primarily due to the factors previously noted related to the fluctuations in adjusted net earnings (loss) from operations, together with the impact of net changes in non-cash working capital.

Adjusted funds flow for 2022 was \$19,791 million (\$17.44 per common share) compared with \$13,733 million (\$11.63 per common share) for 2021 (2020 – \$5,200 million; \$4.40 per common share). The fluctuations in adjusted funds flow for 2022 from 2021 was primarily due to the factors noted above related to the fluctuations in cash flows from operating activities, excluding the impact of the net change in non-cash working capital, abandonment expenditures, government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets, including the unamortized cost of the share bonus program.

## PRODUCTION VOLUMES

Crude oil and NGLs production before royalties for 2022 of 933,149 bbl/d was comparable with 952,404 bbl/d in 2021 (2020 – 917,958 bbl/d). Natural gas production before royalties for 2022 increased 23% to average 2,090 MMcf/d from 1,695 MMcf/d in 2021 (2020 – 1,477 MMcf/d). Total production before royalties for 2022 of 1,281,434 BOE/d increased 4% from 1,234,906 BOE/d in 2021 (2020 – 1,164,136 BOE/d). Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

## PRODUCT PRICES

In the Company's Exploration and Production segments, the 2022 realized crude oil and NGLs prices<sup>(1)</sup> increased 42% to average \$90.64 per bbl from \$63.71 per bbl in 2021 (2020 – \$31.90 per bbl), and the 2022 realized natural gas price increased 61% to average \$6.55 per Mcf from \$4.07 per Mcf in 2021 (2020 – \$2.40 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2022 realized SCO sales price increased 51% to average \$117.69 per bbl from \$77.95 per bbl in 2021 (2020 – \$43.98 per bbl). Crude oil and NGLs and natural gas prices are discussed in detail in the "Business Environment", "Realized Product Prices - Exploration and Production", and the "Oil Sands Mining and Upgrading" sections of this MD&A.

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

## PRODUCTION EXPENSE

In the Company's Exploration and Production segments, the 2022 crude oil and NGLs production expense <sup>(1)</sup> increased 24% to average \$18.17 per bbl from \$14.71 per bbl in 2021 (2020 – \$12.42 per bbl), and natural gas production expense <sup>(1)</sup> averaged \$1.22 per Mcf in 2022, an increase of 3% from \$1.18 per Mcf in 2021 (2020 – \$1.18 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2022 production expense <sup>(1)</sup> averaged \$26.04 per bbl, an increase of 25% from \$20.91 per bbl in 2021 (2020 – \$20.46 per bbl). Crude oil and NGLs and natural gas production expense is discussed in detail in the "Exploration and Production" and the "Oil Sands Mining and Upgrading" sections of this MD&A.

## SUMMARY OF QUARTERLY FINANCIAL RESULTS

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

(\$ millions, except per common share amounts)

<b>2022</b>	<b>Total</b>	<b>Dec 31</b>	<b>Sep 30</b>	<b>Jun 30</b>	<b>Mar 31</b>
Product sales <sup>(1)</sup>	\$ 49,530	\$ 11,012	\$ 12,574	\$ 13,812	\$ 12,132
Crude oil and NGLs	\$ 43,009	\$ 9,508	\$ 11,001	\$ 11,727	\$ 10,773
Natural gas	\$ 5,236	\$ 1,287	\$ 1,342	\$ 1,605	\$ 1,002
Net earnings	\$ 10,937	\$ 1,520	\$ 2,814	\$ 3,502	\$ 3,101
Net earnings per common share					
– basic	\$ 9.64	\$ 1.37	\$ 2.52	\$ 3.04	\$ 2.66
– diluted	\$ 9.52	\$ 1.36	\$ 2.49	\$ 3.00	\$ 2.63

(\$ millions, except per common share amounts)

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

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

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

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

- **Crude oil pricing** – Fluctuating global supply/demand including crude oil production levels from OPEC+ and its impact on world supply; the impact of geopolitical and market uncertainties, including those due to COVID-19 and in connection with governmental responses to COVID-19 and the impact of the Russian invasion of Ukraine, on worldwide benchmark pricing; the impact of shale oil production in North America; the impact of the WCS Heavy Differential from WTI in North America; and the impact of the differential between WTI and Brent benchmark pricing in the International segments.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, third-party pipeline maintenance and outages, the impact of geopolitical and market uncertainties, the impact of seasonal conditions, and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production from the Kirby and Jackfish Thermal Oil Sands Projects, fluctuations in production due to the cyclic nature of the Primrose thermal oil projects, fluctuations in the Company's drilling program in North America and the International segments, natural decline rates, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and the impact of shut-in production due to lower demand during COVID-19. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's drilling program in North America and the International segments, natural decline rates, the temporary shutdown and subsequent reinstatement of the Pine River Gas Plant during 2021, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impacts of the demand and cost for services, fluctuations in product mix and production volumes, seasonal conditions, increased carbon tax and energy costs, inflationary cost pressures, cost optimizations across all segments, the impact and timing of acquisitions, turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.
- **Depletion, depreciation and amortization expense** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and a recoverability charge relating to the de-booking of reserves at the Ninian field in the North Sea.
- **Share-based compensation** – Fluctuations due to the measurement of fair market value of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Interest expense** – Fluctuations due to changing long-term debt levels, and the impact of movements in benchmark interest rates on outstanding floating rate long-term debt and accrued interest on the deferred PRT recovery.
- **Foreign exchange** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company receives for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses were also recorded with respect to US dollar denominated debt, partially offset by the impact of any cross currency swap hedges outstanding.
- **Gain on acquisitions, (gain) loss from investments and income from NWRP** – Fluctuations due to the recognition of gains on acquisitions, (gain) loss from the investments in PrairieSky Royalty Ltd. and Inter Pipeline Ltd. shares, and the distribution from NWRP in 2021.

## Business Environment

Global benchmark crude oil prices increased significantly in the first half of 2022, primarily in response to the impact of the Russian invasion of Ukraine and the OPEC+ decision to adhere to previously agreed upon production cut agreements, together with the improvement of global economic conditions and outlook due to the lessening of COVID-19 restrictions. In the second half of 2022, global benchmark crude oil prices decreased from levels in the first half of 2022 due to demand concerns related to the temporary reinstatement of COVID-19 restrictions in China, the impact of rising interest rates and concerns of a global recession.

### Liquidity

As at December 31, 2022, the Company had undrawn revolving bank credit facilities of \$5,520 million. Including cash and cash equivalents and short-term investments, the Company had approximately \$6,931 million in liquidity <sup>(1)</sup>. The Company also has certain other dedicated credit facilities supporting letters of credit.

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

### Capital Spending

Safe, reliable, effective and efficient operations continue to be a focus for the Company. On November 30, 2022, the Company announced its 2023 base capital budget <sup>(2)</sup> targeted at approximately \$4,190 million. The budget also includes incremental strategic growth capital of approximately \$1,020 million that targets to add additional production and capacity growth beyond 2023 in the Company's E&P segment, and long life low decline thermal in situ and Oil Sands Mining and Upgrading assets. Production for 2023 is targeted between 1,330,000 BOE/d and 1,374,000 BOE/d. Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, in the context of price volatility, project returns and the balancing of project risks and time horizons. The 2023 capital budget constitutes forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

### Risks and Uncertainties

COVID-19, including variants of concern, continues to have the potential to further disrupt the Company's operations, projects, and financial condition, through the disruption of the local or global supply chain and transportation services, or the loss of manpower, any of which may require the Company to temporarily reduce or shut down its operations depending on their extent and severity. The global economy, including Canada, is experiencing higher and more persistent inflation, in part due to the Russian invasion of Ukraine and ongoing supply constraints due to the impacts of COVID-19. As a result of these conditions, the Company has experienced and may continue to experience higher than normal fluctuations in commodity prices, and may experience inflationary pressures on operating and capital expenditures.

## BENCHMARK COMMODITY PRICES

(Yearly average)		2022		2021		2020
WTI benchmark price (US\$/bbl)	\$	94.23	\$	67.96	\$	39.40
Dated Brent benchmark price (US\$/bbl)	\$	99.80	\$	70.49	\$	42.27
WCS Heavy Differential from WTI (US\$/bbl)	\$	18.26	\$	13.04	\$	12.57
SCO price (US\$/bbl)	\$	98.66	\$	66.36	\$	36.26
Condensate benchmark price (US\$/bbl)	\$	93.69	\$	68.24	\$	36.97
Condensate Differential from WTI (US\$/bbl)	\$	0.54	\$	(0.28)	\$	2.43
NYMEX benchmark price (US\$/MMBtu)	\$	6.64	\$	3.85	\$	2.08
AECO benchmark price (C\$/GJ)	\$	5.28	\$	3.38	\$	2.12
US/Canadian dollar average exchange rate (US\$)	\$	0.7686	\$	0.7979	\$	0.7454
US/Canadian dollar year end exchange rate (US\$)	\$	0.7389	\$	0.7901	\$	0.7840

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

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

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

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US\$94.23 per bbl for 2022, an increase of 39% from US\$67.96 per bbl for 2021 (2020 – US\$39.40 per bbl).

Crude oil sales contracts for the Company's International segments are typically based on Brent pricing, which is representative of international markets and overall global supply and demand. Brent averaged US\$99.80 per bbl for 2022, an increase of 42% from US\$70.49 per bbl for 2021 (2020 – US\$42.27 per bbl).

The increase in WTI and Brent pricing for 2022 from 2021 primarily reflected the impact of the Russian invasion of Ukraine, the OPEC+ decision to adhere to the previously agreed upon production cut agreements, and an increase in global demand for crude oil due to improved economic conditions as a result of the lessening of earlier COVID-19 restrictions.

The WCS Heavy Differential averaged US\$18.26 per bbl for 2022, compared with US\$13.04 per bbl for 2021 (2020 – US\$12.57 per bbl). The widening of the WCS Heavy Differential for 2022 from 2021 primarily reflected weakening US Gulf Coast pricing due to increased sour supply from the US Strategic Petroleum Reserve and lower Russian pricing as a result of the Ukraine invasion.

The SCO price averaged US\$98.66 per bbl for 2022, an increase of 49% from US\$66.36 per bbl for 2021 (2020 – US\$36.26 per bbl). The increase in SCO pricing for 2022 from 2021 primarily reflected the increase in WTI benchmark pricing.

NYMEX natural gas prices averaged US\$6.64 per MMBtu for 2022, an increase of 72% from US\$3.85 per MMBtu for 2021 (2020 – US\$2.08 per MMBtu). The increase in NYMEX natural gas prices for 2022 from 2021 primarily reflected increased global commodity prices due to lower European inventories and the Russian invasion of Ukraine.

AECO natural gas prices averaged \$5.28 per GJ for 2022, an increase of 56% from \$3.38 per GJ for 2021 (2020 – \$2.12 per GJ). The increase in AECO natural gas prices for 2022 from 2021 primarily reflected lower storage levels and increased NYMEX benchmark pricing.

## Analysis of Changes in Product Sales

(\$ millions)	2020	Changes due to			2021	Changes due to			2022	
		Volumes	Prices	Other		Volumes	Prices	Other		
<b>North America</b>										
Crude oil and NGLs	\$ 7,480	\$ 82	\$ 6,916	\$ —	\$ 14,478	\$ 286	\$ 5,991	\$ —	\$ 20,755	
Natural gas	1,242	193	1,049	—	2,484	584	1,863	—	4,931	
Other <sup>(1)</sup>	41	—	—	78	119	—	—	98	217	
	8,763	275	7,965	78	17,081	870	7,854	98	25,903	
<b>North Sea</b>										
Crude oil and NGLs	417	(72)	262	—	607	(183)	199	—	623	
Natural gas	12	(8)	1	—	5	(2)	10	—	13	
Other <sup>(1)</sup>	3	—	—	(4)	(1)	—	—	1	—	
	432	(80)	263	(4)	611	(185)	209	1	636	
<b>Offshore Africa</b>										
Crude oil and NGLs	318	(68)	170	—	420	45	229	—	694	
Natural gas	42	(9)	(2)	—	31	2	22	—	55	
Other <sup>(1)</sup>	18	—	—	(11)	7	—	—	1	8	
	378	(77)	168	(11)	458	47	251	1	757	
<b>Oil Sands Mining and Upgrading</b>										
Crude oil and NGLs	7,389	560	6,084	—	14,033	(592)	7,363	—	20,804	
Other <sup>(1)</sup>	139	—	—	(66)	73	—	—	76	149	
	7,528	560	6,084	(66)	14,106	(592)	7,363	76	20,953	
<b>Midstream and Refining</b>										
Midstream activities	83	—	—	(5)	78	—	—	2	80	
Refined product sales and other <sup>(1)</sup>	202	—	—	479	681	—	—	225	906	
	285	—	—	474	759	—	—	227	986	
<b>Intersegment eliminations and other <sup>(2)</sup></b>										
Product sales	74	—	—	(238)	(164)	—	—	454	290	
Other <sup>(1)</sup>	31	—	—	(28)	3	—	—	2	5	
	105	—	—	(266)	(161)	—	—	456	295	
<b>Total</b>	<b>\$ 17,491</b>	<b>\$ 678</b>	<b>\$ 14,480</b>	<b>\$ 205</b>	<b>\$ 32,854</b>	<b>\$ 140</b>	<b>\$ 15,677</b>	<b>\$ 859</b>	<b>\$ 49,530</b>	

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

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

Product sales increased 51% to \$49,530 million for 2022 from \$32,854 million for 2021 (2020 – \$17,491 million). The increase in product sales was primarily a result of increased WTI benchmark pricing due to increased demand for refined products as a result of improved economic conditions. Crude oil and NGLs and natural gas pricing are discussed in detail in the "Business Environment", "Exploration and Production" and the "Oil Sands Mining and Upgrading" sections of this MD&A. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

For 2022, 3% of the Company's crude oil and NGLs and natural gas product sales were generated outside of North America (2021 – 3%; 2020 – 5%). North Sea accounted for 1% of crude oil and NGLs and natural gas product sales for 2022 (2021 – 2%; 2020 – 3%), and Offshore Africa accounted for 2% of crude oil and NGLs and natural gas product sales for 2022 (2021 – 1%; 2020 – 2%).

# Daily Production

## DAILY PRODUCTION, BEFORE ROYALTIES

	2022	2021	2020
<b>Crude oil and NGLs (bbl/d)</b>			
North America – Exploration and Production	<b>479,971</b>	472,621	460,443
North America – Oil Sands Mining and Upgrading <sup>(1)</sup>	<b>425,945</b>	448,133	417,351
International – Exploration and Production			
North Sea	<b>12,890</b>	17,633	23,142
Offshore Africa	<b>14,343</b>	14,017	17,022
Total International <sup>(2)</sup>	<b>27,233</b>	31,650	40,164
Total Crude oil and NGLs	<b>933,149</b>	952,404	917,958
<b>Natural gas (MMcf/d) <sup>(3)</sup></b>			
North America	<b>2,075</b>	1,680	1,450
International			
North Sea	<b>2</b>	3	12
Offshore Africa	<b>13</b>	12	15
Total International	<b>15</b>	15	27
Total Natural gas	<b>2,090</b>	1,695	1,477
Total Barrels of oil equivalent (BOE/d)	<b>1,281,434</b>	1,234,906	1,164,136
<b>Product mix</b>			
Light and medium crude oil and NGLs	<b>11%</b>	10%	11%
Pelican Lake heavy crude oil	<b>4%</b>	5%	5%
Primary heavy crude oil	<b>5%</b>	5%	6%
Bitumen (thermal oil)	<b>20%</b>	21%	21%
Synthetic crude oil <sup>(1)</sup>	<b>33%</b>	36%	36%
Natural gas	<b>27%</b>	23%	21%
<b>Percentage of gross revenue <sup>(1) (4)</sup></b>			
(excluding Midstream and Refining revenue)			
Crude oil and NGLs	<b>88%</b>	91%	91%
Natural gas	<b>12%</b>	9%	9%

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

(2) "International" includes North Sea and Offshore Africa Exploration and Production segments in all instances used.

(3) Natural gas production volumes approximate sales volumes.

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

## DAILY PRODUCTION, NET OF ROYALTIES

	2022	2021	2020
<b>Crude oil and NGLs (bbl/d)</b>			
North America – Exploration and Production	<b>374,089</b>	404,637	420,906
North America – Oil Sands Mining and Upgrading	<b>351,740</b>	410,385	413,363
International – Exploration and Production			
North Sea	<b>12,849</b>	17,588	23,086
Offshore Africa	<b>12,972</b>	13,354	16,306
Total International	<b>25,821</b>	30,942	39,392
Total Crude oil and NGLs	<b>751,650</b>	845,964	873,661
<b>Natural gas (MMcf/d)</b>			
North America	<b>1,885</b>	1,593	1,406
International			
North Sea	<b>2</b>	3	12
Offshore Africa	<b>11</b>	11	14
Total International	<b>13</b>	14	26
Total Natural gas	<b>1,898</b>	1,607	1,432
Total Barrels of oil equivalent (BOE/d)	<b>1,068,063</b>	1,113,878	1,112,364

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

Total 2022 production before royalties averaged 1,281,434 BOE/d, an increase of 4% from 1,234,906 BOE/d in 2021 (2020 – 1,164,136 BOE/d).

Crude oil and NGLs production before royalties for 2022 averaged 933,149 bbl/d, comparable with 952,404 bbl/d for 2021 (2020 – 917,958 bbl/d).

Annual crude oil and NGLs production for 2022 was slightly below the Company's previously issued production forecast of 943,000 bbl/d. Annual crude oil and NGLs production for 2023 is targeted to average between 969,000 bbl/d and 1,001,000 bbl/d. Production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Natural gas production before royalties accounted for 27% of the Company's total production in 2022 on a BOE basis. Natural gas production for 2022 of 2,090 MMcf/d increased 23% from 1,695 MMcf/d for 2021 (2020 – 1,477 MMcf/d). The increase in natural gas production for 2022 from 2021 primarily reflected strong drilling results and the acquisition completed in 2021, partially offset by natural field declines and the impact of extreme cold weather conditions late in the fourth quarter of 2022.

Annual natural gas production for 2022 was slightly below the Company's previously issued production forecast of 2,112 MMcf/d. Annual natural gas production for 2023 is targeted to average between 2,170 MMcf/d and 2,242 MMcf/d. Production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

### North America – Exploration and Production

North America crude oil and NGLs production before royalties for 2022 averaged 479,971 bbl/d, comparable with 472,621 bbl/d for 2021 (2020 – 460,443 bbl/d).

Thermal oil production before royalties for 2022 averaged 252,018 bbl/d, a decrease of 3% from 259,284 bbl/d for 2021 (2020 – 248,971 bbl/d). The decrease in thermal oil production for 2022 from 2021 primarily reflected natural field declines.

Pelican Lake heavy crude oil production before royalties averaged 50,333 bbl/d for 2022, a decrease of 7% from 54,390 bbl/d for 2021 (2020 – 56,535 bbl/d), primarily reflecting a temporary injection reduction in 2022, together with natural field declines.

Natural gas production before royalties for 2022 averaged 2,075 MMcf/d, an increase of 24% from 1,680 MMcf/d for 2021 (2020 – 1,450 MMcf/d). The increase in natural gas production for 2022 from 2021 primarily reflected strong drilling results and the acquisition completed in 2021, partially offset by natural field declines and the impact of extreme cold weather conditions late in the fourth quarter of 2022.

## North America – Oil Sands Mining and Upgrading

SCO production before royalties for 2022 of 425,945 bbl/d decreased 5% from 448,133 bbl/d for 2021 (2020 – 417,351 bbl/d). The decrease in SCO production for 2022 from 2021 primarily reflected the extended turnaround at the Scotford Upgrader ("Scotford") in the first half of 2022, the unplanned outage at Horizon during October, and the impact of extreme cold weather conditions late in the fourth quarter of 2022 at both mines.

## International – Exploration and Production

International crude oil and NGLs production before royalties for 2022 averaged 27,233 bbl/d, a decrease of 14% from 31,650 bbl/d for 2021 (2020 – 40,164 bbl/d). The decrease in production for 2022 from 2021 primarily reflected natural field declines, together with the impact of maintenance activities in the North Sea in 2022.

## INTERNATIONAL CRUDE OIL INVENTORY VOLUMES

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

(bbl)	2022	2021	2020
International	<b>390,959</b>	727,439	972,133

## Exploration and Production

### OPERATING HIGHLIGHTS

	2022	2021	2020
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>			
Realized price <sup>(2)</sup>	\$ <b>90.64</b>	\$ 63.71	\$ 31.90
Transportation <sup>(2)</sup>	<b>4.13</b>	3.86	3.85
Realized price, net of transportation <sup>(2)</sup>	<b>86.51</b>	59.85	28.05
Royalties <sup>(3)</sup>	<b>18.91</b>	8.59	2.59
Production expense <sup>(4)</sup>	<b>18.17</b>	14.71	12.42
Netback <sup>(2)</sup>	\$ <b>49.43</b>	\$ 36.55	\$ 13.04
<b>Natural gas (\$/Mcf) <sup>(1)</sup></b>			
Realized price <sup>(5)</sup>	\$ <b>6.55</b>	\$ 4.07	\$ 2.40
Transportation <sup>(6)</sup>	<b>0.51</b>	0.45	0.43
Realized price, net of transportation	<b>6.04</b>	3.62	1.97
Royalties <sup>(3)</sup>	<b>0.61</b>	0.22	0.08
Production expense <sup>(4)</sup>	<b>1.22</b>	1.18	1.18
Netback	\$ <b>4.21</b>	\$ 2.22	\$ 0.71
<b>Barrels of oil equivalent (\$/BOE) <sup>(1)</sup></b>			
Realized price <sup>(2)</sup>	\$ <b>70.07</b>	\$ 49.67	\$ 26.15
Transportation <sup>(2)</sup>	<b>3.72</b>	3.44	3.44
Realized price, net of transportation <sup>(2)</sup>	<b>66.35</b>	46.23	22.71
Royalties <sup>(3)</sup>	<b>12.75</b>	5.98	1.89
Production expense <sup>(4)</sup>	<b>13.76</b>	11.98	10.67
Netback <sup>(2)</sup>	\$ <b>39.84</b>	\$ 28.27	\$ 10.15

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

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

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

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

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

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

## REALIZED PRODUCT PRICES – EXPLORATION AND PRODUCTION

		2022		2021		2020
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>						
North America <sup>(2)</sup>	\$	<b>88.43</b>	\$	62.10	\$	30.31
International average <sup>(3)</sup>	\$	<b>128.41</b>	\$	87.04	\$	50.46
North Sea <sup>(3)</sup>	\$	<b>129.04</b>	\$	87.98	\$	50.09
Offshore Africa <sup>(3)</sup>	\$	<b>127.85</b>	\$	85.71	\$	50.95
Crude oil and NGLs average <sup>(2)</sup>	\$	<b>90.64</b>	\$	63.71	\$	31.90
<b>Natural gas (\$/Mcf) <sup>(1) (3)</sup></b>						
North America	\$	<b>6.51</b>	\$	4.05	\$	2.34
International average	\$	<b>12.78</b>	\$	6.21	\$	5.56
North Sea	\$	<b>15.75</b>	\$	2.94	\$	2.74
Offshore Africa	\$	<b>12.23</b>	\$	7.17	\$	7.77
Natural gas average	\$	<b>6.55</b>	\$	4.07	\$	2.40
Average (\$/BOE) <sup>(1) (2)</sup>	\$	<b>70.07</b>	\$	49.67	\$	26.15

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

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

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

### North America

North America realized crude oil and NGLs prices increased 42% to average \$88.43 per bbl for 2022 from \$62.10 per bbl for 2021 (2020 – \$30.31 per bbl), primarily due to higher WTI benchmark pricing.

The Company continues to focus on its crude oil blending marketing strategy including a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil and bitumen (thermal oil) conversion capacity. During 2022, the Company contributed approximately 179,000 bbl/d of heavy crude oil blends to the WCS stream.

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

North America realized natural gas prices increased 61% to average \$6.51 per Mcf for 2022 from \$4.05 per Mcf for 2021 (2020 – \$2.34 per Mcf). The increase in realized natural gas prices for 2022 from 2021 primarily reflected increased AECO benchmark pricing.

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

(Yearly average)		2022		2021		2020
<b>Wellhead Price <sup>(1)</sup></b>						
Light and medium crude oil and NGLs (\$/bbl)	\$	<b>88.24</b>	\$	61.29	\$	33.42
Pelican Lake heavy crude oil (\$/bbl)	\$	<b>96.18</b>	\$	68.05	\$	33.57
Primary heavy crude oil (\$/bbl)	\$	<b>93.80</b>	\$	65.88	\$	31.81
Bitumen (thermal oil) (\$/bbl)	\$	<b>85.51</b>	\$	60.20	\$	28.11
Natural gas (\$/Mcf)	\$	<b>6.51</b>	\$	4.05	\$	2.34

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

### International

International realized crude oil and NGLs prices increased 48% to average \$128.41 per bbl for 2022 from \$87.04 per bbl for 2021 (2020 – \$50.46 per bbl). Realized crude oil and NGLs prices per barrel in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The increase in realized crude oil and NGLs prices for 2022 from 2021 reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

## ROYALTIES – EXPLORATION AND PRODUCTION

		2022		2021		2020
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>						
North America	\$	<b>19.64</b>	\$	9.06	\$	2.72
International average	\$	<b>6.38</b>	\$	1.75	\$	0.99
North Sea	\$	<b>0.30</b>	\$	0.19	\$	0.12
Offshore Africa	\$	<b>11.79</b>	\$	3.94	\$	2.17
Crude oil and NGLs average	\$	<b>18.91</b>	\$	8.59	\$	2.59
<b>Natural gas (\$/Mcf) <sup>(1)</sup></b>						
North America	\$	<b>0.61</b>	\$	0.22	\$	0.07
Offshore Africa	\$	<b>1.50</b>	\$	0.33	\$	0.37
Natural gas average	\$	<b>0.61</b>	\$	0.22	\$	0.08
Average (\$/BOE) <sup>(1)</sup>	\$	<b>12.75</b>	\$	5.98	\$	1.89

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

### North America

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

North America crude oil and NGLs and natural gas royalties for 2022 and the comparable periods reflected movements in benchmark commodity prices, fluctuations in the WCS Heavy Differential and the impact of sliding scale royalty rates.

Crude oil and NGLs royalty rates <sup>(1)</sup> averaged approximately 22% of product sales for 2022 compared with 15% of product sales for 2021 (2020 – 9%). The increase in royalty rates for 2022 from 2021 was primarily due to higher benchmark prices together with fluctuations in the WCS Heavy Differential.

Natural gas royalty rates averaged approximately 9% of product sales for 2022, compared with 5% of product sales for 2021 (2020 – 3%). The increase in royalty rates for 2022 from 2021 was primarily due to higher benchmark prices.

### Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 9% for 2022 compared with 5% of product sales for 2021 (2020 – 4%). Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

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

## PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

		2022		2021		2020
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>						
North America	\$	16.25	\$	13.12	\$	11.21
International average	\$	51.01	\$	37.77	\$	26.60
North Sea	\$	88.99	\$	54.13	\$	36.51
Offshore Africa	\$	17.25	\$	14.73	\$	13.29
Crude oil and NGLs average	\$	18.17	\$	14.71	\$	12.42
<b>Natural gas (\$/Mcf) <sup>(1)</sup></b>						
North America	\$	1.19	\$	1.15	\$	1.14
International average	\$	5.16	\$	5.07	\$	3.64
North Sea	\$	9.27	\$	7.31	\$	3.72
Offshore Africa	\$	4.40	\$	4.41	\$	3.58
Natural gas average	\$	1.22	\$	1.18	\$	1.18
Average (\$/BOE) <sup>(1)</sup>	\$	13.76	\$	11.98	\$	10.67

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

### North America

North America crude oil and NGLs production expense for 2022 averaged \$16.25 per bbl, an increase of 24% from \$13.12 per bbl for 2021 (2020 – \$11.21 per bbl). The increase in crude oil and NGLs production expense per bbl for 2022 from 2021 primarily reflected higher energy and service costs.

North America natural gas production expense for 2022 averaged \$1.19 per Mcf, an increase of 3% from \$1.15 per Mcf for 2021 (2020 – \$1.14 per Mcf). The increase in natural gas production expense per Mcf for 2022 from 2021 primarily reflected higher energy costs.

### International

International crude oil and NGLs production expense for 2022 averaged \$51.01 per bbl, an increase of 35% from \$37.77 per bbl for 2021 (2020 – \$26.60 per bbl). The increase in crude oil production expense per bbl for 2022 from 2021 primarily reflected the timing of liftings from various fields that have different cost structures, the impact of lower production volumes, higher energy costs, and fluctuations in foreign exchange.

## DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

(\$ millions, except per BOE amounts)		2022		2021		2020
North America	\$	3,595	\$	3,569	\$	3,780
North Sea		1,747		160		277
Offshore Africa		173		142		190
Depletion, Depreciation and Amortization	\$	5,515	\$	3,871	\$	4,247
Less: Recoverability charge <sup>(1)</sup>		1,620		—		—
Adjusted depletion, depreciation and amortization <sup>(2)</sup>	\$	3,895	\$	3,871	\$	4,247
\$/BOE <sup>(3)</sup>	\$	12.45	\$	13.49	\$	15.45

(1) Prevailing regulatory and economic conditions in 2022 and the increasingly challenging commercial outlook in the United Kingdom, including the impact of higher natural gas and carbon costs, led the Company to assess the viability of its North Sea operations. Following a detailed review of its development plans, the Company determined that the Ninian field is no longer economic, de-booked associated crude oil reserves as at December 31, 2022, and is accelerating abandonment. As a result, the Company completed a recoverability assessment of its assets in the North Sea, and recognized a recoverability charge of \$1,620 million in depletion, depreciation and amortization.

(2) This is a non-GAAP measure used to calculate depletion, depreciation and amortization, excluding the impact of non-recurring charges that do not reflect the Company's normal course depletion, depreciation and amortization costs. It may not be comparable to similar measures presented by other companies, and should not be considered an alternative to or more meaningful than the most directly comparable financial measure presented in the financial statements (depletion, depreciation and amortization expense), as applicable, as an indication of the Company's performance. It is calculated as depletion, depreciation and amortization expense, less the impact of non-recurring charges.

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

Adjusted depletion, depreciation and amortization expense for 2022 of \$12.45 per BOE decreased 8% from \$13.49 per BOE for 2021 (2020 – \$15.45 per BOE). The decrease in adjusted depletion, depreciation and amortization expense per BOE for 2022 from 2021 primarily reflected lower depletion rates due to increases to the Company's North America E&P reserve estimates at December 31, 2021, including the impact of acquisitions completed during the prior year.

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

## ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

(\$ millions, except per BOE amounts)	2022		2021		2020
North America	\$	171	\$	101	\$ 97
North Sea		33		21	30
Offshore Africa		7		6	6
Asset Retirement Obligation Accretion	\$	211	\$	128	\$ 133
\$/BOE <sup>(1)</sup>	\$	0.67	\$	0.44	\$ 0.48

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

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

Asset retirement obligation accretion expense for 2022 of \$0.67 per BOE increased 52% from \$0.44 per BOE for 2021 (2020 – \$0.48 per BOE). The increase in asset retirement obligation accretion expense per BOE for 2022 from 2021 primarily reflected the cost estimate and discount rate revisions made to the asset retirement obligation in 2021 and 2022.

## Oil Sands Mining and Upgrading

### OPERATING HIGHLIGHTS

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the Horizon and AOSP sites. SCO production in 2022 averaged 425,945 bbl/d, reflecting the extended turnaround at Scotford in the first half of 2022, the unplanned outage at Horizon in October, and the impact of extreme cold weather conditions late in the fourth quarter at both mines.

The Company incurred production expense of \$4,076 million for 2022, an increase of 19% from \$3,414 million for 2021, reflecting increased energy and maintenance services costs.

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

(\$/bbl)	2022		2021		2020
Realized SCO sales price <sup>(1)</sup>	\$	117.69	\$	77.95	\$ 43.98
Bitumen value for royalty purposes <sup>(2)</sup>	\$	83.07	\$	58.39	\$ 25.82
Bitumen royalties <sup>(3)</sup>	\$	20.71	\$	6.62	\$ 0.51
Transportation <sup>(1)</sup>	\$	1.71	\$	1.21	\$ 1.23

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

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

(3) Calculated as royalties divided by sales volumes.

The realized SCO sales price averaged \$117.69 per bbl for 2022, an increase of 51% from \$77.95 per bbl for 2021 (2020 – \$43.98 per bbl). The increase in the realized SCO sales price for 2022 compared to 2021 primarily reflected the increase in WTI benchmark pricing.

The increase in bitumen royalties per bbl for 2022 from 2021 primarily reflected the impact of Horizon reaching full payout in 2022, together with higher prevailing bitumen pricing and higher sliding scale royalty rates.

Transportation expense averaged \$1.71 per bbl for 2022, an increase of 41% from \$1.21 per bbl for 2021 (2020 – \$1.23 per bbl). The increase in transportation expense for 2022 from 2021 primarily reflected the impact of higher pipeline tolls, partially offset by lower sales volumes.

## PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

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

(\$ millions)		<b>2022</b>		2021		2020
Production expense, excluding natural gas costs	<b>\$</b>	<b>3,743</b>	<b>\$</b>	3,176	<b>\$</b>	2,968
Natural gas costs		<b>333</b>		238		146
Production expense	<b>\$</b>	<b>4,076</b>	<b>\$</b>	3,414	<b>\$</b>	3,114

  

(\$/bbl)		<b>2022</b>		2021		2020
Production expense, excluding natural gas costs <sup>(1)</sup>	<b>\$</b>	<b>23.91</b>	<b>\$</b>	19.45	<b>\$</b>	19.50
Natural gas costs <sup>(2)</sup>		<b>2.13</b>		1.46		0.96
Production expense <sup>(3)</sup>	<b>\$</b>	<b>26.04</b>	<b>\$</b>	20.91	<b>\$</b>	20.46
Sales volumes (bbl/d)		<b>428,820</b>		447,230		415,741

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

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

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

Production expense for 2022 of \$26.04 per bbl increased 25% from \$20.91 per bbl for 2021 (2020 – \$20.46 per bbl). The increase in production expense per bbl for 2022 as compared to 2021 primarily reflected increased energy and maintenance services costs, together with lower production volumes.

## DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

(\$ millions, except per bbl amounts)		<b>2022</b>		2021		2020
Depletion, depreciation and amortization	<b>\$</b>	<b>1,822</b>	<b>\$</b>	1,838	<b>\$</b>	1,784
\$/bbl <sup>(1)</sup>	<b>\$</b>	<b>11.64</b>	<b>\$</b>	11.26	<b>\$</b>	11.73

(1) Calculated as depletion, depreciation and amortization divided by sales volumes.

Depletion, depreciation and amortization expense for 2022 of \$11.64 per bbl increased 3% from \$11.26 per bbl for 2021 (2020 – \$11.73 per bbl), reflecting lower production volumes in 2022.

## ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

(\$ millions, except per bbl amounts)		<b>2022</b>		2021		2020
Asset retirement obligation accretion	<b>\$</b>	<b>70</b>	<b>\$</b>	57	<b>\$</b>	72
\$/bbl <sup>(1)</sup>	<b>\$</b>	<b>0.45</b>	<b>\$</b>	0.35	<b>\$</b>	0.47

(1) Calculated as asset retirement obligation accretion divided by sales volumes.

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

Asset retirement obligation accretion expense for 2022 of \$0.45 per bbl increased 29% from \$0.35 per bbl for 2021 (2020 – \$0.47 per bbl). The increase in asset retirement obligation accretion expense on a per barrel basis for 2022 from 2021 primarily reflected the impact of cost estimate and discount rate revisions made to the asset retirement obligation during 2022.

## Midstream and Refining

(\$ millions)	2022	2021	2020
Product sales			
Midstream activities	\$ 80	\$ 78	\$ 83
NWRP, refined product sales and other	906	681	202
Segmented revenue	986	759	285
Less:			
NWRP, refining toll	247	213	166
Midstream activities	24	21	18
Production expense	271	234	184
NWRP, transportation and feedstock costs	691	550	181
Depreciation	16	15	15
Income from NWRP	—	(400)	—
Segmented earnings (loss)	\$ 8	\$ 360	\$ (95)

The Company's Midstream and Refining assets consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose and the Company's 50% equity investment in NWRP. Approximately 25% of the Company's heavy crude oil production was transported to international mainline liquid pipelines via the 100% owned and operated ECHO and Pelican Lake pipelines. The Midstream pipeline asset ownership allows the Company to control transportation costs, earn third party revenue, and manage the marketing of heavy crude oils.

NWRP operates a 50,000 bbl/d bitumen upgrader and refinery that processes approximately 12,500 bbl/d (25% toll payer) of bitumen feedstock for the Company and 37,500 bbl/d (75% toll payer) of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period until 2058. Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment. Production of ultra-low sulphur diesel and other refined products for 2022 averaged 58,351 BOE/d (14,588 BOE/d to the Company), reflecting turnaround activities during the year (2021 – 69,713 BOE/d; 17,428 BOE/d to the Company).

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

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

To facilitate the Optimization Transaction, NWRP issued \$500 million of 1.20% series L senior secured bonds due December 2023, \$500 million of 2.00% series M senior secured bonds due December 2026, \$1,000 million of 2.80% series N senior secured bonds due June 2031, and \$600 million of 3.75% series O senior secured bonds due June 2051.

During 2022, NWRP extended its \$3,000 million syndicated credit facility and increased it to \$3,175 million. The revolving portion of the credit facility was increased to \$2,175 million, with \$118 million maturing in June 2023, and \$2,057 million maturing in June 2025. The \$1,000 million non-revolving portion of the credit facility was extended, with \$60 million maturing in June 2023, and \$940 million maturing in June 2025. During 2022, NWRP also entered into a \$150 million facility to support letters of credit. As at December 31, 2022, NWRP had borrowings of \$2,318 million under the syndicated credit facility (December 31, 2021 – \$1,981 million).

As at December 31, 2022, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was \$551 million (2021 – \$562 million). The recovery of the unrecognized share of equity losses from NWRP for 2022 was \$11 million (2021 – unrecognized equity loss of \$9 million and partnership distributions of \$400 million; 2020 – unrecognized equity loss of \$94 million).

## Corporate and Other

### ADMINISTRATION EXPENSE

	2022		2021		2020	
Expense (\$ millions)	\$	415	\$	366	\$	391
\$/BOE <sup>(1)</sup>	\$	0.88	\$	0.81	\$	0.92
Sales volumes (BOE/d) <sup>(2)</sup>		<b>1,285,877</b>		1,233,457		1,166,862

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

(2) Total Company sales volumes.

Administration expense for 2022 of \$0.88 per BOE increased 9% from \$0.81 per BOE for 2021 (2020 – \$0.92 per BOE). Administration expense per BOE increased for 2022 from 2021 primarily due to higher personnel costs, partially offset by the impact of higher overhead recoveries.

### SHARE-BASED COMPENSATION

(\$ millions)	2022		2021		2020	
Expense (recovery)	\$	804	\$	514	\$	(82)

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

The Company recognized \$804 million of share-based compensation expense for 2022, primarily as a result of the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period, and changes in the Company's share price. An expense of \$101 million related to PSUs granted to certain executive employees was included in the share-based compensation expense for 2022 (2021 – \$79 million expense; 2020 – \$21 million expense).

### INTEREST AND OTHER FINANCING EXPENSE

(\$ millions, except effective interest rate)	2022		2021		2020	
Interest and other financing expense	\$	549	\$	711	\$	756
Interest income and other <sup>(1)</sup>		121		32		72
Capitalized interest <sup>(1)</sup>		—		—		24
Interest on long-term debt and lease liabilities <sup>(1)</sup>	\$	670	\$	743	\$	852
Average current and long-term debt <sup>(2)</sup>	\$	13,986	\$	18,935	\$	22,446
Average lease liabilities <sup>(2)</sup>		1,531		1,619		1,708
Average long-term debt and lease liabilities <sup>(2)</sup>	\$	15,517	\$	20,554	\$	24,154
Average effective interest rate <sup>(3) (4)</sup>		4.3%		3.5%		3.5%
Interest and other financing expense per \$/BOE <sup>(5)</sup>	\$	1.17	\$	1.58	\$	1.77
Sales volumes (BOE/d) <sup>(6)</sup>		<b>1,285,877</b>		1,233,457		1,166,862

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

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

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

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

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

(6) Total Company sales volumes.

Interest and other financing expense per BOE for 2022 decreased 26% to \$1.17 per BOE from \$1.58 per BOE for 2021 (2020 – \$1.77 per BOE). The decrease in interest and other financing expense per BOE for 2022 from 2021 was primarily due to lower debt levels in 2022 and accrued interest on the deferred PRT recovery.

The Company's average effective interest rate of 4.3% for 2022 increased from 2021 primarily due to higher prevailing interest rates on floating rate debt held during 2022.

## RISK MANAGEMENT ACTIVITIES

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

(\$ millions)		<b>2022</b>		2021		2020
Foreign currency contracts	<b>\$</b>	<b>(37)</b>	<b>\$</b>	1	<b>\$</b>	16
Natural gas financial instruments <sup>(1)</sup>		<b>13</b>		17		16
Crude oil and NGLs financial instruments <sup>(1)</sup>		<b>17</b>		(1)		—
Net realized (gain) loss		<b>(7)</b>		17		32
Foreign currency contracts		<b>(16)</b>		6		(3)
Natural gas financial instruments <sup>(1)</sup>		<b>(10)</b>		11		(36)
Crude oil and NGLs financial instruments <sup>(1)</sup>		<b>(2)</b>		2		—
Net unrealized (gain) loss		<b>(28)</b>		19		(39)
Net (gain) loss	<b>\$</b>	<b>(35)</b>	<b>\$</b>	36	<b>\$</b>	(7)

(1) Commodity financial instruments were assumed in the acquisition of Storm Resources Ltd. ("Storm") and Painted Pony Energy Ltd. ("Painted Pony") in 2021 and 2020, respectively.

During 2022, net realized risk management gains were related to the settlement of foreign currency contracts, partially offset by losses on natural gas financial instruments, and crude oil and NGLs financial instruments. The Company recorded a net unrealized gain of \$28 million (\$25 million after-tax of \$3 million) on its risk management activities for 2022 (2021 – \$19 million unrealized loss, \$16 million after-tax of \$3 million; 2020 – \$39 million unrealized gain, \$31 million after-tax of \$8 million).

Further details related to outstanding derivative financial instruments as at December 31, 2022 are disclosed in note 19 to the Company's audited consolidated financial statements.

## FOREIGN EXCHANGE

(\$ millions)		<b>2022</b>		2021		2020
Net realized (gain) loss	<b>\$</b>	<b>(114)</b>	<b>\$</b>	78	<b>\$</b>	(159)
Net unrealized loss (gain)		<b>852</b>		(205)		(116)
Net loss (gain) <sup>(1)</sup>	<b>\$</b>	<b>738</b>	<b>\$</b>	(127)	<b>\$</b>	(275)

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

The net realized foreign exchange gain for 2022 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the settlement of the US\$550 million cross currency swap during 2022. The net unrealized foreign exchange loss for 2022 was primarily related to the impact of a weaker Canadian dollar with respect to outstanding US dollar debt and the reclassification of the gain on the US\$550 million cross currency swap to realized foreign exchange due to its settlement in 2022. The US/Canadian dollar exchange rate at December 31, 2022 was US\$0.7389 (December 31, 2021 – US\$0.7901, December 31, 2020 – US\$0.7840).

## INCOME TAXES

(\$ millions, except effective tax rates)	2022		2021		2020
North America <sup>(1)</sup>	\$	2,789	\$	1,841	\$ (245)
North Sea		69		7	(4)
Offshore Africa		74		21	17
PRT – North Sea		(42)		(34)	(31)
Other taxes		16		13	6
Current income tax		2,906		1,848	(257)
Deferred corporate income tax		302		399	(181)
Deferred PRT – North Sea		(441)		—	—
Deferred income tax		(139)		399	(181)
Income tax	\$	2,767	\$	2,247	\$ (438)
Earnings (loss) before taxes	\$	13,704	\$	9,911	\$ (873)
Effective tax rate on net earnings (loss) <sup>(2)</sup>		20%		23%	50%

(\$ millions, except effective tax rates)	2022		2021		2020
Income tax	\$	2,767	\$	2,247	\$ (438)
Tax effect on non-operating items <sup>(3)</sup>		964		5	29
Current PRT – North Sea		42		34	31
Other taxes		(16)		(13)	(6)
Effective tax on adjusted net earnings (loss)	\$	3,757	\$	2,273	\$ (384)
Adjusted net earnings (loss) from operations <sup>(4)</sup>	\$	12,863	\$	7,420	\$ (756)
Adjusted net earnings (loss) from operations, before taxes	\$	16,620	\$	9,693	\$ (1,140)
Effective tax rate on adjusted net earnings (loss) from operations <sup>(5) (6)</sup>		23%		23%	34%

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

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

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

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

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

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

The effective tax rate on net earnings (loss) and adjusted net earnings (loss) from operations for 2022 and the comparable years included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings (loss).

The current corporate income tax and PRT in the North Sea in 2022 and the prior periods included the impact of carrybacks of PRT losses, including expenditures related to decommissioning activities at the Company's platforms in the North Sea. Deferred PRT and income taxes for 2022 also reflected the impact of the recoverability charge recognized in depletion, depreciation, and amortization.

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

During 2022, the Company filed Scientific Research and Experimental Development claims of approximately \$283 million (2021 – \$229 million; 2020 – \$246 million) relating to qualifying research and development expenditures for Canadian income tax purposes.

# Net Capital Expenditures <sup>(1) (2)</sup>

(\$ millions)	2022		2021		2020	
<b>Exploration and Evaluation</b>						
Net expenditures	\$	36	\$	12	\$	36
Net property dispositions		(3)		(11)		(31)
Total Exploration and Evaluation		33		1		5
<b>Property, Plant and Equipment</b>						
Net property acquisitions <sup>(3) (4)</sup>		513		1,112		536
Well drilling, completion and equipping		1,545		918		429
Production and related facilities		1,233		802		580
Other		59		64		60
Total Property, Plant and Equipment		3,350		2,896		1,605
Total Exploration and Production		3,383		2,897		1,610
<b>Oil Sands Mining and Upgrading</b>						
Project costs		294		236		258
Sustaining capital		1,171		1,035		839
Turnaround costs		287		145		196
Net property dispositions		(40)		—		—
Other <sup>(5)</sup>		7		331		30
Total Oil Sands Mining and Upgrading		1,719		1,747		1,323
<b>Midstream and Refining</b>		9		9		5
<b>Head office</b>		25		23		19
<b>Abandonments expenditures, net <sup>(2)</sup></b>		335		232		249
Net capital expenditures	\$	5,471	\$	4,908	\$	3,206
<b>By segment</b>						
North America <sup>(3) (4)</sup>	\$	3,133	\$	2,662	\$	1,389
North Sea		126		173		122
Offshore Africa		124		62		99
Oil Sands Mining and Upgrading		1,719		1,747		1,323
Midstream and Refining		9		9		5
Head office		25		23		19
Abandonments expenditures, net <sup>(2)</sup>		335		232		249
Net capital expenditures	\$	5,471	\$	4,908	\$	3,206

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

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

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

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

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

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

Net capital expenditures for 2022 were \$5,471 million compared with \$4,908 million for 2021. Net capital expenditures for 2022 included base capital expenditures <sup>(1)</sup> of \$3,956 million and strategic growth capital expenditures <sup>(1)</sup> of \$1,045 million, in accordance with the Company's capital budget. The Company also completed strategic acquisitions <sup>(1)</sup> of \$470 million during 2022.

(1) Item is a component of net capital expenditures. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A for more details on Net Capital Expenditures.

## 2023 CAPITAL BUDGET

On November 30, 2022, the Company announced its 2023 base capital budget <sup>(1)</sup> targeted at approximately \$4,190 million. The budget also includes incremental strategic growth capital of approximately \$1,020 million that targets to add additional production and capacity growth beyond 2023 in the Company's E&P segments, and long life low decline thermal in situ and Oil Sands Mining and Upgrading assets.

The 2023 capital budget constitutes forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

### DRILLING ACTIVITY <sup>(1) (2)</sup>

(number of net wells)	2022	2021	2020
Net successful crude oil wells <sup>(3)</sup>	317	149	42
Net successful natural gas wells	72	49	30
Dry wells	1	1	—
Total	390	199	72
Success rate	99%	99%	100%

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

(2) During 2022, on a net basis, the Company drilled 373 stratigraphic and 5 service wells in the Oil Sands Mining and Upgrading segment, 18 stratigraphic and 53 service wells in the Company's thermal oil projects, and 3 service wells in Northwest Alberta.

(3) Includes bitumen wells.

### North America

During 2022, the Company drilled 72 net natural gas wells, 176 net primary heavy crude oil wells, 6 net Pelican Lake heavy crude oil wells, 104 net bitumen (thermal oil) wells and 32 net light crude oil wells.

## Liquidity and Capital Resources

(\$ millions, except ratios)	2022	2021	2020
Adjusted working capital <sup>(1)</sup>	\$ (1,190)	\$ (480)	\$ 626
Long-term debt, net <sup>(2)</sup>	\$ 10,525	\$ 13,950	\$ 21,269
Shareholders' equity	\$ 38,175	\$ 36,945	\$ 32,380
Debt to book capitalization <sup>(2)</sup>	22%	27%	40%
After-tax return on average capital employed <sup>(3)</sup>	22%	16%	—%

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

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

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

As at December 31, 2022, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Business Environment" section and in the "Risks and Uncertainties" section of this MD&A. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and market conditions. The Company continues to believe its internally generated cash flows from operating activities, supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long-term and support its growth strategy.

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

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default;

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

- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Reviewing the Company's borrowing capacity:
  - During 2021, the \$1,000 million non-revolving term credit facility originally due February 2022, was extended to February 2023. Additionally in 2021, the facility was fully repaid and amended to allow for a re-draw of the full \$1,000 million until March 31, 2022. During 2022, the Company repaid and cancelled the \$500 million non-revolving portion of the \$1,000 million term credit facility, reducing the remaining facility to the \$500 million revolving facility maturing February 2023, and extended this facility from February 2023 to February 2024.
  - During 2021, the Company repaid \$1,500 million of the \$2,650 million non-revolving term credit facility due February 2023, reducing the outstanding balance to \$1,150 million. During 2022, the Company repaid and cancelled the \$1,150 million non-revolving term credit facility maturing in February 2023.
  - During 2022, the Company discontinued its £5 million demand credit facility related to its North Sea operations.
  - During 2021, the Company extended both of its \$2,425 million revolving credit facilities originally maturing June 2022 and June 2023, to June 2024 and June 2025, respectively and increased each by \$70 million. In accordance with the terms of the extension, and by mutual agreement, \$70 million of the original revolving credit facilities were not extended and will mature upon the original maturity date of June 2022 and June 2023, respectively. The revolving syndicated credit facilities are extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
  - During 2021, the outstanding balance of \$3,088 million on the non-revolving term credit facility was repaid and the facility was cancelled.
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US\$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
  - Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, SOFR, US base rate or Canadian prime rate.
  - During 2022, the Company repaid through market purchases \$498 million of medium-term notes with interest rates ranging from 1.45% to 3.55%, originally due between 2023 and 2028.
  - During 2022, the Company repaid \$1,000 million of 3.31% medium-term notes.
  - During 2021, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to \$3,000 million of medium-term notes in Canada, which expires in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
  - During 2022, the Company early repaid US\$1,000 million of 2.95% debt securities, originally due January 15, 2023.
  - During 2021, the Company repaid US\$500 million of 3.45% debt securities.
  - During 2021, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US\$3,000 million of debt securities in the United States, which expires in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

As at December 31, 2022, the Company had undrawn revolving bank credit facilities of \$5,520 million. Including cash and cash equivalents and short-term investments, the Company had approximately \$6,931 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit.

During 2022, the Company settled the US\$550 million cross currency swap designated as a cash flow hedge of a portion of the US\$1,100 million 6.25% US dollar debt securities due March 2038. The Company realized cash proceeds of \$158 million on settlement. As at December 31, 2022, the Company had no cross currency swap contracts outstanding. As at December 31, 2022, there were no foreign currency contracts designated as cash flow hedges.

Long-term debt, net was \$10,525 million at December 31, 2022, resulting in a debt to book capitalization ratio <sup>(1)</sup> of 22% (December 31, 2021 – 27%, December 31, 2020 – 40%); this ratio was below the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities are greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at December 31, 2022 are discussed in note 11 to the Company's audited consolidated financial statements.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at December 31, 2022, the Company was in compliance with this covenant.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2022 are discussed in note 19 to the Company's audited consolidated financial statements.

As at December 31, 2022, the maturity dates of long-term debt and other long-term liabilities and related interest payments were as follows:

		Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt <sup>(1)</sup>	\$	404	\$ 1,009	\$ 3,757	\$ 6,344
Other long-term liabilities <sup>(2)</sup>	\$	247	\$ 156	\$ 416	\$ 724
Interest and other financing expense <sup>(3)</sup>	\$	584	\$ 577	\$ 1,410	\$ 3,790

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

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, \$244 million; one to less than two years, \$156 million; two to less than five years, \$416 million; and thereafter, \$724 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2022.

## SHARE CAPITAL

As at December 31, 2022, there were 1,102,636,000 common shares outstanding (December 31, 2021 – 1,168,369,000 common shares) and 31,150,000 stock options outstanding. As at February 28, 2023, the Company had 1,099,741,000 common shares outstanding and 31,902,000 stock options outstanding.

On March 1, 2023, the Board of Directors approved a 6% increase in the quarterly dividend to \$0.90 per common share, beginning with the dividend payable on April 5, 2023.

On November 2, 2022, the Board of Directors approved a 13% increase in the quarterly dividend to \$0.85 per common share, beginning with the dividend paid on January 5, 2023.

On August 3, 2022, the Board of Directors approved a special dividend of \$1.50 per common share, paid on August 31, 2022.

On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to \$0.75 per common share. On November 3, 2021, the Board of Directors approved a 25% increase in the quarterly dividend to \$0.5875 per common share. On March 3, 2021, the Board of Directors approved an 11% increase in the quarterly dividend to \$0.47 per common share, from \$0.425 per common share. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 8, 2022, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), up to 101,574,207 common shares, representing 10% of the public float, over a 12-month period commencing March 11, 2022 and ending March 10, 2023.

During 2022, the Company purchased 77,338,200 common shares at a weighted average price of \$72.03 per common share for a total cost of \$5,571 million. Retained earnings were reduced by \$4,868 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2022, up to and including February 28, 2023, the Company purchased 6,000,000 common shares at a weighted average price of \$77.72 per common share for a total cost of \$466 million.

On March 1, 2023, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the TSX to purchase, by way of Normal Course Issuer Bid, up to 10% of the public float (as determined in accordance with the rules of the TSX) of its issued and outstanding common shares. Subject to acceptance of the Notice of Intention by the TSX, the purchases would be made through facilities of the TSX, alternative Canadian trading platforms, and the NYSE.

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

## Commitments and Contingencies

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2022:

(\$ millions)	2023	2024	2025	2026	2027	Thereafter
Product transportation and processing <sup>(1)</sup>	\$ 1,171	\$ 1,349	\$ 1,168	\$ 1,102	\$ 1,052	11,095
North West Redwater Partnership service toll <sup>(2)</sup>	\$ 151	\$ 152	\$ 151	\$ 133	\$ 118	4,884
Offshore vessels and equipment	\$ 44	\$ 35	\$ —	\$ —	\$ —	—
Field equipment and power	\$ 36	\$ 27	\$ 24	\$ 23	\$ 22	215
Other	\$ 23	\$ 24	\$ 21	\$ 16	\$ —	—

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

(2) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is \$2,863 million of interest payable over the 40-year tolling period, ending in 2058.

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

### LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

## Reserves

For the years ended December 31, 2022 and 2021, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's total proved and total proved plus probable reserves. The evaluation and review was conducted and prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

The following are reconciliation tables of the Company gross total proved and total proved plus probable reserves using forecast prices and costs as at the effective date of December 31, 2022:

<b>Total Proved</b>	<b>Light and Medium Crude Oil</b>	<b>Primary Heavy Crude Oil</b>	<b>Pelican Lake Heavy Crude Oil</b>	<b>Bitumen (Thermal Oil)</b>	<b>Synthetic Crude Oil</b>	<b>Natural Gas</b>	<b>Natural Gas Liquids</b>	<b>Barrels of Oil Equivalent</b>
	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(Bcf)	(MMbbl)	(MMBOE)
December 31, 2021 <sup>(1)</sup>	300	169	270	2,631	6,998	12,168	418	12,813
Discoveries	—	—	—	—	—	—	—	—
Extensions	3	14	—	262	—	290	13	339
Infill Drilling	7	5	—	—	—	218	19	68
Improved Recovery	—	—	—	2	37	—	—	40
Acquisitions	—	—	—	431	—	249	25	498
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	10	6	4	—	—	446	9	103
Technical Revisions	(61)	11	6	50	(6)	1,019	23	194
Production	(28)	(25)	(18)	(92)	(155)	(763)	(22)	(468)
December 31, 2022 <sup>(1)</sup>	<b>231</b>	<b>179</b>	<b>262</b>	<b>3,284</b>	<b>6,873</b>	<b>13,627</b>	<b>486</b>	<b>13,587</b>

<b>Total Proved Plus Probable</b>	<b>Light and Medium Crude Oil</b>	<b>Primary Heavy Crude Oil</b>	<b>Pelican Lake Heavy Crude Oil</b>	<b>Bitumen (Thermal Oil)</b>	<b>Synthetic Crude Oil</b>	<b>Natural Gas</b>	<b>Natural Gas Liquids</b>	<b>Barrels of Oil Equivalent</b>
	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(Bcf)	(MMbbl)	(MMBOE)
December 31, 2021 <sup>(1)</sup>	424	249	388	4,337	7,535	20,249	643	16,950
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	26	—	337	—	829	35	539
Infill Drilling	10	8	—	—	—	344	26	100
Improved Recovery	—	—	1	2	50	—	—	52
Acquisitions	—	—	—	551	—	588	72	722
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	10	7	3	—	—	528	11	120
Technical Revisions	(100)	8	2	50	(20)	495	8	29
Production	(28)	(25)	(18)	(92)	(155)	(763)	(22)	(468)
December 31, 2022 <sup>(1)</sup>	<b>320</b>	<b>272</b>	<b>376</b>	<b>5,186</b>	<b>7,408</b>	<b>22,270</b>	<b>772</b>	<b>18,046</b>

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

At December 31, 2022, the total proved crude oil, bitumen (thermal oil) and NGLs reserves were 11,316 MMbbl, and total proved plus probable crude oil, bitumen (thermal oil) and NGLs reserves were 14,334 MMbbl. Total proved reserves additions and revisions replaced 256% of 2022 production. Additions to total proved reserves resulting from exploration and development activities, acquisitions, dispositions and future offset additions amounted to 818 MMbbl, and additions to total proved plus probable reserves amounted to 1,120 MMbbl. Net positive revisions amounted to 53 MMbbl for total proved reserves and net negative revisions amounted to 21 MMbbl for total proved plus probable reserves, primarily due to technical revisions.

At December 31, 2022, the total proved natural gas reserves were 13,627 Bcf, and total proved plus probable natural gas reserves were 22,270 Bcf. Total proved reserves additions and revisions replaced 291% of 2022 production. Additions to total proved reserves resulting from exploration and development activities, acquisitions, dispositions and future offset additions amounted to 757 Bcf, and additions to total proved plus probable reserves amounted to 1,761 Bcf.

Net positive revisions amounted to 1,465 Bcf for total proved reserves, primarily due to technical revisions and economic factors. Net positive revisions amounted to 1,023 Bcf for total proved plus probable reserves, primarily due to economic factors and technical revisions.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and related net present value of future net revenue of the remaining reserves. Additional reserves information is annually disclosed in the AIF.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States FASB Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual report on Form 40-F filed with the SEC and in the "Supplementary Oil and Gas Information" section of the Company's annual report.

## Risks and Uncertainties

The Company is exposed to various operational risks inherent in the exploration, development, production and marketing of crude oil and NGLs and natural gas and the mining, extracting and upgrading of bitumen into SCO. These inherent risks include, but are not limited to, the following:

- Volatility in the prevailing prices of crude oil and NGLs, natural gas and refined products;
- The ability to find, produce and replace reserves, whether sourced from exploration, improved recovery or acquisitions, at a reasonable cost, including the risk of reserves revisions due to economic and technical factors. Reserves revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Reservoir quality and uncertainty of reserves estimates;
- Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
- Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting and upgrading the Company's bitumen products;
- Timing and success of integrating the business and operations of acquired companies and assets;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
- Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
- Foreign exchange risk due to the effect of fluctuating exchange rates on the Company's US dollar denominated debt and revenue from sales predominantly based on US dollar denominated benchmarks;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Future legislative and regulatory developments related to environmental regulation, including but not limited to GHG compliance costs and reduction targets;
- The timing and pace of change to a low carbon economy is uncertain and the ability to access insurance and capital may be adversely affected in the event that financial institutions, investors, insurers, rating agencies and/or lenders adopt more restrictive decarbonisation policies;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations, including but not limited to restrictions on production and the certainty and timelines for regulatory processes;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;
- Changing royalty regimes;
- Business interruptions because of unexpected events such as fires or explosions whether caused by human error or nature, severe storms and other calamitous acts of nature, blowouts, freeze-ups, mechanical or equipment failures of facilities and infrastructure and other similar events affecting the Company or other parties whose operations or assets directly or indirectly impact the Company and that may or may not be financially recoverable;
- Epidemics or pandemics, such as COVID-19, have the potential to disrupt the Company's operations, projects and financial condition through the disruption of the local or global supply chain and transportation services, or the loss of manpower resulting from quarantines that affect the Company's labour pools in the local communities, workforce camps or operating sites or that are instituted by local health authorities as a precautionary measure, any of which may require the Company to temporarily reduce or shutdown its operations depending on the extent and severity of a potential outbreak and the areas or operations impacted. Depending on the severity, a large scale epidemic or pandemic could impact international demand for commodities and have a corresponding impact on the prices realized by the Company, which could have a material adverse effect on the Company's financial condition;

- The ability to secure adequate transportation for products, which could be affected by pipeline constraints, the construction by third parties of new or expansion of existing pipeline capacity and other factors;
- The access to markets for the Company's products;
- The risk of significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach that could adversely affect the Company's operations;
- Liquidity risk related to the Company's ability to fulfill financial obligations as they become due or ability to liquidate assets in a timely manner at a reasonable price; and
- Other circumstances affecting revenue and expenses.

The Company uses a variety of means to seek to mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company seeks to manage these risks by monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default. Derivative financial instruments are periodically utilized to help ensure targets are met and to manage commodity price, foreign currency and interest rate exposures. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company seeks to manage this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions. Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper and access to debt capital markets, to meet obligations as they become due. The Company has implemented cyber security protocols and procedures designed to reduce the risk of failure or a significant breach of the Company's information technology systems and related data and control systems.

The Company has safety, integrity and environmental management systems to recover and process crude oil and natural gas resources safely, efficiently, and in an environmentally sustainable manner and mitigate risk.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

For additional details regarding the Company's risks and uncertainties, refer to the Company's AIF for the year ended December 31, 2022.

## Environment

The Company has a Corporate Statement on Environmental Management which affirms that environmental stewardship is a fundamental value of the Company. The Company continues to invest in people, proven and new technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner. Environmental, social, economic and health considerations are evaluated in new project designs and in operations to improve environmental performance. Processes are employed to avoid, mitigate, minimize or compensate for environmental effects. Working with local communities, the Company considers the interests and values of the people using the land in proximity to its operations, and where appropriate, adapts projects to recognize those matters.

The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation compliance, particularly in North America and the North Sea. Existing and expected legislation and regulations may require the Company to address and mitigate the effect of its activities on the environment. The Company has processes in place to meet all existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings.

The Company's associated environmental risk management strategies incorporate working with legislators and regulators on any new or revised policies, legislation or regulations to reflect a balanced approach to sustainable development. Specific measures in response to existing or new legislation include a focus on the Company's energy efficiency, air emissions management, water management and land management to minimize disturbance impacts. The Company's environmental risk management strategies employ an Environmental Management Plan (the "Plan"). As part of risk management, the Company develops, assesses and implements technologies and innovative practices that will improve environmental performance, often through collaborative efforts with industry partners, governments and research institutions. Details of the Plan, along with performance results, are presented to, and reviewed by, the Board of Directors quarterly.

The Plan and the Company's operating guidelines focus on minimizing the impact of operations while meeting regulatory requirements, regional management frameworks for air quality and emissions, ground and surface water and biodiversity, industry operating standards and guidelines, and internal corporate standards. Training and due diligence for operators and contractors is key to the effectiveness of the Company's environmental management programs and the prevention of incidents to protect the environment. The Company, as part of this Plan, has implemented proactive programs that include:

- Environmental planning to assess impacts and implement avoidance and mitigation programs in order to maintain biodiversity for terrestrial and aquatic systems and high value ecosystems;
- Continued evaluation of new technologies to reduce environmental impacts, including support for Canada's Oil Sands Innovation Alliance ("COSIA"), the innovation arm of Pathways, Petroleum Technology Alliance Canada ("PTAC") and other research institutions;
- Mitigation of the Company's climate change impacts through implementation of various CO<sub>2</sub> emissions reduction and carbon capture projects including: CO<sub>2</sub> injection for EOR, CO<sub>2</sub> injection in tailings and the Quest Carbon Capture and Storage Facility; a methane emissions reduction program, including solution gas conservation to reduce methane venting, and an equipment retrofit program to reduce methane emissions from pneumatic equipment; and optimization of efficiencies at the Company's facilities;
- Water programs to improve efficiency of use and recycle rates as well as to reduce fresh water use;
- Groundwater monitoring for all thermal in situ and mine operations;
- Effective reclamation and decommissioning programs across the Company's operations. In North America, well abandonment and progressive reclamation of large contiguous areas of land provides the foundation for the enhancement of biodiversity and functional wildlife habitats. In the Company's International operations, decommissioning activities were completed at Murchison and Ninian North and were advanced at Banff and Kyle;
- Tailings management in Oil Sands Mining to minimize fine tailings and promote progressive reclamation;
- Monitoring programs to assess changes to biodiversity, wildlife and fisheries in order to manage construction and operation effects and to assess reclamation success;
- Participation and support for the Oil Sands Monitoring Program of regional important resources;
- An active spill prevention and management program;
- Supporting regional air shed monitoring for emissions and their deposition; and
- An internal environmental management system for compliance audit and inspection programs of operating facilities.

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 5.6% (2021 – 4.0%; 2020 – 3.7%). For 2022, the Company's capital expenditures included \$449 million for abandonment expenditures (\$335 million – abandonment expenditures, net) (2021 – \$307 million; 2020 – \$249 million). Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A for further details on abandonments expenditures, net. The Company's estimated discounted ARO at December 31, 2022 was as follows:

(\$ millions)	2022	2021
Exploration and Production		
North America	\$ 4,326	\$ 4,021
North Sea	1,011	821
Offshore Africa	143	170
Oil Sands Mining and Upgrading	1,427	1,793
Midstream and Refining	1	1
	<b>\$ 6,908</b>	<b>\$ 6,806</b>

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine sites, upgrading facilities and tailings, and offshore production platforms. Factors that affect costs include number of wells drilled, well depth, facility size and the specific environmental legislation. The estimated future costs are based on estimates of current costs in accordance with present legislation, industry operating practice and the expected timing of abandonment.

In 2021, the Alberta Energy Regulator ("AER") announced a new Liability Management Framework, enforcing mandatory targets for companies for the closure of inactive wells and facilities. These targets became effective January 1, 2022. During 2022, the AER increased the mandatory targets. Also during 2022, the government of Saskatchewan introduced the Inactive Liability Reduction Program and the government of British Columbia updated its Dormancy and Shutdown Regulations, which provide mandatory targets for decommissioning and restoring inactive wells and facilities in those provinces. The Company has updated its forecasts of future expenditures to settle its ARO liability based on the set and forecasted annual targets. As a result, the Company's ARO liability as at December 31, 2022 was increased on an inflated and discounted basis due to earlier forecasted expenditures to settle liabilities associated with the closure of inactive well and facilities.

## GREENHOUSE GAS AND OTHER EMISSIONS

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

The Company is participating in Pathways, an alliance of oil sands producers working collectively with federal and provincial governments, to achieve the goal of net zero GHG emissions from oil sands operations by 2050 to help Canada meet its climate goals, including its Paris Agreement commitments and 2050 net zero aspirations.

The Company, through industry associations, is working with Canadian legislators and regulators as they develop and implement new GHG emission laws and regulations to support emissions reductions and properly reflect a balanced approach to sustainable development. Internally, the Company is pursuing an integrated emissions reduction strategy, to ensure that it is able to comply with existing and future emissions reduction requirements, for both GHGs and air pollutants (such as sulphur dioxide and oxides of nitrogen). The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new policies encourage technological innovation, energy efficiency, and targeted research and development while not impacting competitiveness.

Governments in jurisdictions in which the Company operates have developed or are developing GHG regulations as part of their national and international climate change commitments. The Company uses existing GHG regulations to determine the impact of compliance costs on current and future projects. The Company monitors the development of GHG regulations on an ongoing basis in the jurisdictions in which it operates to assess the impact of future regulatory developments on the Company's operations and planned projects. In Canada, the federal government has ratified the Paris climate change agreement, with a commitment to reduce GHG emissions by 40 - 45% from 2005 levels by 2030. The Canadian government has also committed to cap and cut emissions from the oil and gas sector, with further details to be developed in 2023. In December 2020, the federal government announced its intention to increase the carbon price to \$170/tonne in 2030. The federal government is also developing a comprehensive management system for air pollutants and has released regulations pertaining to certain boilers, heaters and compressor engines operated by the Company. Additionally, in 2022, the federal government released the Clean Fuel Regulations, which applies to producers or importers of liquid fuels (including gasoline, diesel, kerosene and light and heavy fuel oils).

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

Effective January 1, 2020, the GHG regulation (the Carbon Competitiveness Incentive Regulation) was replaced with the Technology Innovation and Emissions Reduction Regulation ("TIER"). The coverage of TIER has expanded to include all of the Company's assets in Alberta (as an alternative to the federal fuel charge). In December 2022, the Alberta government published changes to TIER effective January 1, 2023 that reduce the amount of emissions allocations for facilities under the regulation. Additionally, emissions coverage within TIER was expanded to include flaring from all TIER regulated facilities. The carbon price in Alberta was \$50/tonne for emissions above the TIER-regulated limits in 2022 and is \$65/tonne in 2023, in alignment with the federal carbon pricing schedule. The Alberta government has published a carbon pricing schedule to 2030 that aligns with the federal carbon pricing schedule for that period. The non-operated Scotford Upgrader and the North West Redwater bitumen upgrader and refinery are also subject to compliance under the regulations.

In British Columbia, carbon tax is currently being assessed at \$50/tonne of CO<sub>2</sub>e on fuel consumed and gas flared and vented in the province. 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<sub>2</sub>e annually and required the North Tangleflags in situ heavy oil facility and the Senlac in situ heavy crude oil facility to meet reduction targets for GHG emissions in 2020. This regulation also enables facilities below the threshold to aggregate and opt into the Saskatchewan regulatory system as an alternative to the federal fuel charge.

The governments of British Columbia and Saskatchewan have announced their intention to follow the federal carbon pricing schedule and associated regulations are expected in 2023.

In Manitoba, the federal output-based pricing system and carbon pricing schedule applies for facilities with emissions greater than or equal to 10 kilotonnes of CO<sub>2</sub>e annually, and the federal fuel charge applies for facilities with emissions of less than 10 kilotonnes of CO<sub>2</sub>e annually.

By 2025, the federal government has committed to reduce methane emissions from the oil and gas sector by 40% to 45% below 2012 levels. The federal government's methane regulation came into effect on January 1, 2020 and applies nationally unless provinces reach equivalency agreements with the federal government, under which the federal regulation would not be in effect for those jurisdictions. The provinces of British Columbia, Alberta and Saskatchewan have implemented provincial methane regulations, and have reached equivalency agreements with the federal government. Accordingly, the applicable provincial methane regulations govern in the three western provinces whereas the federal methane regulation applies to methane emissions in the province of Manitoba. In 2022, the federal government announced a framework for expanding methane regulations to achieve at least a 75% reduction below 2012 levels, by 2030. Draft regulations are expected in 2023.

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

In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 - 2007) of the UK National Allocation Plan, the Company operated below its CO<sub>2</sub> allocation. In Phase 2 (2008 - 2012) the Company's CO<sub>2</sub> allocation was decreased below the Company's operations emissions. In Phase 3 (2013 - 2020) the Company's CO<sub>2</sub> allocation was further reduced. Following the UK's withdrawal from the European Union ("EU") on January 31, 2020, a new UK Emissions Trading Scheme ("ETS") was launched on January 1, 2021. The new scheme is currently aligned with the EU ETS rules and applies to energy intensive industries, the power generation sector and aviation. The Company continues to focus on implementing CO<sub>2</sub> emission reduction program opportunities at its facilities and on trading mechanisms to ensure compliance with requirements now in effect.

# Accounting Policies and Standards

## REGULATORY DEVELOPMENTS

On May 27, 2021, the Canadian Securities Administrators ("CSA") announced the adoption of NI 52-112 and related amendments. This National Instrument replaces the previous CSA staff notice on Non-GAAP Measures. NI 52-112 governs how entities present non-GAAP and other financial measures and ratios. The requirements apply to the Company's MD&A and certain other disclosure documents beginning in 2021.

## CHANGES IN ACCOUNTING POLICIES

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

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in this MD&A and the audited consolidated financial statements for the year ended December 31, 2022.

### A) Depletion, Depreciation and Amortization and Impairment

Exploration and evaluation ("E&E") costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. The judgements associated with the estimation of proved reserves are described below in "Crude Oil and Natural Gas Reserves".

An alternative acceptable accounting method for E&E costs under IFRS 6 "Exploration for and Evaluation of Mineral Resources" is to charge exploratory dry holes and geological and geophysical exploration costs incurred after having obtained the legal rights to explore an area against net earnings in the period incurred rather than capitalizing to E&E assets.

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of related Cash Generating Units ("CGUs"), aggregated at a segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and production costs, discount rates, income taxes, and the potential impact of climate related matters and in accordance with related government regulations. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Crude oil and natural gas properties in the Exploration and Production segments are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future estimated development expenditures required to develop proved reserves. Estimates of proved reserves have a significant impact on net earnings, as they are a key input to the calculation of depletion expense.

The Company assesses property, plant and equipment for impairment discounted at rates currently ranging from 10% to 12% whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low commodity prices for an extended period, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs a recoverability assessment related to the specific assets at the CGU level.

## **B) Crude Oil and Natural Gas Reserves**

Reserves estimates are based on estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations and judgements, including the potential impact of climate related matters and in accordance with related government regulations. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion, depreciation and amortization charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of E&E and property, plant and equipment carrying amounts.

## **C) Asset Retirement Obligations**

The Company is required to recognize a liability for ARO associated with its property, plant and equipment. An ARO liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total ARO amount, including the potential impact of climate related matters and in accordance with related government regulations. These individual assumptions may be subject to change.

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's weighted average credit-adjusted risk-free interest rate, which is currently 5.6%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

## **D) Income Taxes**

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted that are expected to apply when the asset or liability is recovered. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

## **E) Risk Management Activities**

The Company periodically uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The carrying amount of a risk management liability is adjusted for the Company's own credit risk. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

## **F) Purchase Price Allocations**

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

The Company has made various assumptions in determining the fair values of acquired assets and liabilities. The most significant assumptions and judgements relate to the estimation of the fair value of crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates crude oil and natural gas reserves. Reserves estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgements associated with these estimated reserves are described above in "Crude Oil and Natural Gas Reserves". Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

### **G) Share-Based Compensation**

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

### **H) Leases**

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

### **I) Government Grants**

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

## **Control Environment**

The Company's management, including the President and the Chief Financial Officer and Vice-President, Finance and Principal Accounting Officer, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2022, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized and reported within the time periods specified and such information is accumulated and communicated to the Company's management to allow timely decisions regarding required disclosures.

The Company's management, including the President and the Chief Financial Officer and Vice-President, Finance and Principal Accounting Officer, also evaluated the effectiveness of internal control over financial reporting as at December 31, 2022, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2022 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal control over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

## Non-GAAP and Other Financial Measures

This MD&A includes references to non-GAAP and other financial measures as defined in NI 52-112. These financial measures are used by the Company to evaluate its financial performance, financial position or cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies, and should not be considered an alternative to or more meaningful than the most directly comparable financial measure presented in the Company's audited consolidated financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this MD&A, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below.

### ADJUSTED NET EARNINGS (LOSS) FROM OPERATIONS

Adjusted net earnings (loss) from operations is a non-GAAP financial measure that adjusts net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), for non-operating items, net of tax. The Company considers adjusted net earnings (loss) from operations a key measure in evaluating its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. A reconciliation for adjusted net earnings (loss) from operations is presented below.

(\$ millions)	2022	2021	2020
Net earnings (loss)	\$ 10,937	\$ 7,664	\$ (435)
Share-based compensation, net of tax <sup>(1)</sup>	780	495	(86)
Unrealized risk management (gain) loss, net of tax <sup>(2)</sup>	(25)	16	(31)
Unrealized foreign exchange loss (gain), net of tax <sup>(3)</sup>	852	(205)	(116)
Realized foreign exchange (gain) loss, net of tax <sup>(4)</sup>	(62)	118	(166)
Gain on acquisitions, net of tax <sup>(5)</sup>	—	(478)	(217)
(Gain) loss from investments, net of tax <sup>(6)</sup>	(182)	(132)	185
Recoverability charge, net of tax <sup>(7)</sup>	651	—	—
Other, net of tax <sup>(8)</sup>	(88)	(58)	110
Non-operating items, net of tax	1,926	(244)	(321)
Adjusted net earnings (loss) from operations	\$ 12,863	\$ 7,420	\$ (756)

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and PSU plan. The fair value of the share-based compensation is recognized as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings (loss). Pre-tax share-based compensation for 2022 was an expense of \$804 million (2021 – \$514 million expense; 2020 – \$82 million recovery).

(2) Derivative financial instruments are recognized at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings (loss). The amounts ultimately realized may be materially different than those amounts reflected in the Company's audited consolidated financial statements due to changes in prices of the underlying items hedged, primarily crude oil, natural gas and foreign exchange. Pre-tax unrealized risk management gain for 2022 was \$28 million (2021 – \$19 million loss; 2020 – \$39 million gain).

(3) Unrealized foreign exchange losses and gains result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, partially offset by the impact of cross currency swaps, and are recognized in net earnings (loss). Pre- and after-tax amounts for these unrealized foreign exchange losses and gains are the same.

(4) During 2022, the Company early repaid US\$1,000 million of 2.95% debt securities, originally due January 15, 2023, resulting in a realized foreign exchange loss of \$7 million. Also, during 2022, the Company settled the US\$550 million cross currency swap designated as a cash flow hedge of a portion of the US\$1,100 million 6.25% US dollar debt securities due March 2038, resulting in a realized foreign exchange gain of \$69 million. During 2021, the Company repaid US\$500 million of 3.45% debt securities, resulting in a realized foreign exchange loss of \$118 million. During 2020, the Company settled the US\$500 million cross currency swaps designated as cash flow hedges of the US\$500 million 3.45% US dollar debt securities, originally due November 2021, resulting in a realized foreign exchange gain of \$166 million. Pre- and after-tax amounts for these realized foreign exchange gains and losses are the same.

(5) During 2021, the Company completed two acquisitions resulting in a pre- and after-tax gain of \$478 million. During 2020, the Company recognized a pre- and after-tax gain of \$217 million related to the acquisition of Painted Pony.

(6) The Company's investments have been accounted for at fair value through profit and loss and are measured each period with (gains) losses recognized in net earnings (loss). There is zero net tax impact on these (gains) losses from investments.

(7) The Company recognized a recoverability charge of \$1,620 million in depletion, depreciation and amortization at December 31, 2022 relating to the de-booking of reserves at the Ninian field in the North Sea. Prevailing regulatory and economic conditions in 2022 and the increasingly challenging commercial outlook in the United Kingdom, including the impact of higher natural gas and carbon costs, led the Company to assess the viability of its North Sea operations. Following a detailed review of its development plans, the Company determined that the Ninian field is no longer economic, de-booked associated crude oil reserves as at December 31, 2022, and is accelerating abandonment.

(8) During 2022, the Company recognized the impact of government grant income under the provincial well-site rehabilitation programs of \$114 million (2021 – \$75 million). During 2020, the Company recognized a provision in transportation, blending and feedstock expense of \$143 million relating to the Keystone XL pipeline project.

## ADJUSTED FUNDS FLOW

Adjusted funds flow is a non-GAAP financial measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment expenditures excluding the impact of government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets. The Company considers adjusted funds flow a key measure in evaluating its performance, as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. A reconciliation for adjusted funds flow, from cash flows from operating activities is presented below.

(\$ millions)	2022		2021		2020
Cash flows from operating activities	\$	19,391	\$	14,478	\$ 4,714
Net change in non-cash working capital		(79)		(964)	166
Abandonment expenditures, net <sup>(1)</sup>		335		232	249
Movements in other long-term assets <sup>(2)</sup>		144		(13)	71
Adjusted funds flow	\$	19,791	\$	13,733	\$ 5,200

(1) Non-GAAP Financial Measure. A reconciliation of abandonment expenditures, net is presented in the "Abandonment Expenditures, net" section below.

(2) Includes the unamortized cost of the share bonus program, accrued interest on the deferred PRT recovery, accrued interest on subordinated debt advances to NWRP and prepaid cost of service tolls.

## ADJUSTED NET EARNINGS (LOSS) FROM OPERATIONS AND ADJUSTED FUNDS FLOW, PER SHARE (BASIC AND DILUTED)

Adjusted net earnings (loss) from operations and adjusted funds flow, per common share (basic and diluted), are non-GAAP ratios that represent those non-GAAP measures divided by the weighted average number of basic and diluted common shares outstanding for the period, respectively, as presented in note 17 to the Company's audited consolidated financial statements. These non-GAAP measures, disclosed on a per share basis, enable a comparison to the per share amounts disclosed in the Company's financial statements prepared in accordance with IFRS.

## ABANDONMENT EXPENDITURES, NET

Abandonment expenditures, net, is a non-GAAP financial measure that represents the abandonment expenditures to settle asset retirement obligations as reflected in the Company's annual capital budget. Abandonment expenditures, net is calculated as abandonment expenditures, as presented in the Company's audited consolidated Statements of Cash Flows, adjusted for the impact of government grant income under the provincial well-site rehabilitation programs. A reconciliation of abandonment expenditures, net is presented below.

(\$ millions)	2022		2021		2020
Abandonment expenditures	\$	449	\$	307	\$ 249
Government grants for abandonment expenditures		(114)		(75)	—
Abandonment expenditures, net	\$	335	\$	232	\$ 249

## NETBACK

Netback is a non-GAAP ratio that represents net cash flows provided from core activities after the impact of all costs associated with bringing a product to market, on a per unit basis. The Company considers netback a key measure in evaluating its performance, as it demonstrates the efficiency and profitability of the Company's activities. Refer to the "Operating Highlights – Exploration and Production", "Per Unit Results – Exploration and Production", and "Per Unit Results – Oil Sands Mining and Upgrading" sections of this MD&A for the netback calculations on a per unit basis for crude oil and NGLs, natural gas and on a total barrels of oil equivalent basis.

The netback calculations include the non-GAAP financial measures: realized price and transportation, reconciled below to their respective line item in note 22 to the Company's audited consolidated financial statements.

## REALIZED PRICE (\$/BBL AND \$/BOE) – EXPLORATION AND PRODUCTION

Realized price (\$/bbl and \$/BOE) is a non-GAAP ratio calculated as realized crude oil and NGLs sales and total realized BOE sales (non-GAAP financial measures) divided by respective sales volumes. Realized crude oil and NGLs sales and total realized BOE sales include the impact of blending costs and other by-product sales. The Company considers realized price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit the Company obtained on the market for its crude oil and NGLs sales volumes and BOE sales volumes.

Reconciliations for Exploration and Production realized crude oil and NGLs sales and BOE sales and the calculations for realized price are presented below.

(\$ millions, except bbl/d and \$/bbl)	2022	2021	2020
<b>Crude oil and NGLs (bbl/d)</b>			
North America	<b>480,691</b>	471,331	465,073
International			
North Sea	<b>13,215</b>	18,942	22,852
Offshore Africa	<b>14,866</b>	13,452	17,017
Total International	<b>28,081</b>	32,394	39,869
Total sales volumes	<b>508,772</b>	503,725	504,942
Crude oil and NGLs sales <sup>(1) (2)</sup>	\$ <b>22,072</b>	\$ 15,505	\$ 8,215
Less: Blending costs <sup>(3)</sup>	<b>5,239</b>	3,792	2,321
Realized crude oil and NGLs sales	\$ <b>16,833</b>	\$ 11,713	\$ 5,894
Realized price (\$/bbl)	\$ <b>90.64</b>	\$ 63.71	\$ 31.90

(1) Crude oil and NGLs sales in note 22 to the Company's audited consolidated financial statements.

(2) Includes other miscellaneous income in the segment.

(3) Blending costs are a component of transportation, blending and feedstock expense as reconciled below in the "Transportation – Exploration and Production" section.

(\$ millions, except BOE/d and \$/BOE)	2022	2021	2020
<b>Barrels of oil equivalent (BOE/d)</b>			
North America	<b>826,526</b>	751,330	706,799
International			
North Sea	<b>13,598</b>	19,512	24,805
Offshore Africa	<b>16,933</b>	15,385	19,517
Total International	<b>30,531</b>	34,897	44,322
Total sales volumes	<b>857,057</b>	786,227	751,121
Barrels of oil equivalent sales <sup>(1) (2)</sup>	\$ <b>27,071</b>	\$ 18,025	\$ 9,511
Less: Blending costs <sup>(3)</sup>	<b>5,239</b>	3,792	2,321
Less: Sulphur (income) expense	<b>(88)</b>	(21)	4
Realized barrels of oil equivalent sales	\$ <b>21,920</b>	\$ 14,254	\$ 7,186
Realized price (\$/BOE)	\$ <b>70.07</b>	\$ 49.67	\$ 26.15

(1) Barrels of oil equivalent sales includes crude oil and NGLs sales and natural gas sales in note 22 to the Company's audited consolidated financial statements.

(2) Includes other miscellaneous income in the segment.

(3) Blending costs are a component of transportation, blending and feedstock expense as reconciled below in the "Transportation – Exploration and Production" section.

## TRANSPORTATION – EXPLORATION AND PRODUCTION

Transportation (\$/BOE, \$/bbl and \$/Mcf) is a non-GAAP ratio calculated as transportation (a non-GAAP financial measure) divided by the respective sales volumes. The Company calculates transportation to demonstrate its cost to deliver products to the market excluding the impact of blending costs. A reconciliation for Exploration and Production transportation and the calculations for transportation on a per unit basis are presented below.

(\$ millions, except \$ per unit amounts)		2022		2021		2020
Transportation, blending and feedstock <sup>(1)</sup>	\$	<b>6,401</b>	\$	4,780	\$	3,409
Less: Blending costs		<b>5,239</b>		3,792		2,321
Less: Other <sup>(2)</sup>		—		—		143
Transportation	\$	<b>1,162</b>	\$	988	\$	945
Transportation (\$/BOE)	\$	<b>3.72</b>	\$	3.44	\$	3.44
Amounts attributed to crude oil and NGLs	\$	<b>767</b>	\$	710	\$	711
Transportation (\$/bbl)	\$	<b>4.13</b>	\$	3.86	\$	3.85
Amounts attributed to natural gas	\$	<b>395</b>	\$	278	\$	234
Transportation (\$/Mcf)	\$	<b>0.51</b>	\$	0.45	\$	0.43

(1) Transportation, blending and feedstock in note 22 to the Company's audited consolidated financial statements.

(2) Transportation excludes the impact of a \$143 million provision recognized in 2020, relating to the Keystone XL pipeline project.

## NORTH AMERICA – REALIZED PRODUCT PRICES AND ROYALTIES

Realized crude oil and NGLs price (\$/bbl) is a non-GAAP ratio calculated as realized crude oil and NGLs sales (non-GAAP financial measure) divided by sales volumes. Realized crude oil and NGLs sales include the impact of blending costs. The Company considers the realized crude oil and NGLs price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its crude oil and NGLs sales volumes.

Crude oil and NGLs royalty rate is a non-GAAP ratio that is calculated as crude oil and NGLs royalties divided by realized crude oil and NGLs sales. The Company considers crude oil and NGLs royalty rate a key measure in evaluating its performance, as it describes the Company's royalties for crude oil and NGLs sales volumes on a per unit basis.

A reconciliation for North America realized crude oil and NGLs sales and the calculations for realized crude oil and NGLs prices and the royalty rates are presented below.

(\$ millions, except \$/bbl and royalty rates)		2022		2021		2020
Crude oil and NGLs sales <sup>(1)</sup>	\$	<b>20,755</b>	\$	14,478	\$	7,480
Less: Blending costs <sup>(2)</sup>		<b>5,239</b>		3,792		2,321
Realized crude oil and NGLs sales	\$	<b>15,516</b>	\$	10,686	\$	5,159
Realized crude oil and NGLs prices (\$/bbl)	\$	<b>88.43</b>	\$	62.10	\$	30.31
Crude oil and NGLs royalties <sup>(3)</sup>	\$	<b>3,445</b>	\$	1,558	\$	464
Crude oil and NGLs royalty rates		<b>22%</b>		15%		9%

(1) Crude oil and NGLs sales in note 22 to the Company's audited consolidated financial statements.

(2) Blending costs are a component of transportation, blending and feedstock expense as reconciled above in the "Transportation – Exploration and Production" section.

(3) Item is a component of royalties in note 22 to the Company's audited consolidated financial statements.

## REALIZED PRODUCT PRICES AND TRANSPORTATION – OIL SANDS MINING AND UPGRADING

Realized SCO sales price (\$/bbl) is a non-GAAP ratio calculated as realized SCO sales (non-GAAP financial measure) including the impact of blending and feedstock costs, divided by SCO sales volumes. The Company considers realized SCO sales price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its SCO sales volumes.

Transportation (\$/bbl) is a non-GAAP ratio calculated as transportation (a non-GAAP financial measure) divided by SCO sales volumes. The Company calculates transportation to demonstrate its cost to deliver product to the market excluding the impact of blending and feedstock costs.

Reconciliations for Oil Sands Mining and Upgrading realized SCO sales and transportation and the calculations for realized SCO sales price and transportation on a per unit basis are presented below.

(\$ millions, except for bbl/d and \$/bbl)	2022		2021		2020	
SCO sales volumes (bbl/d)		<b>428,820</b>		447,230		415,741
Crude oil and NGLs sales <sup>(1) (2)</sup>	\$	<b>20,804</b>	\$	14,033	\$	7,389
Less: Blending and feedstock costs		<b>2,384</b>		1,309		695
Realized SCO sales	\$	<b>18,420</b>	\$	12,724	\$	6,694
Realized SCO sales price (\$/bbl)	\$	<b>117.69</b>	\$	77.95	\$	43.98
Transportation, blending and feedstock <sup>(3)</sup>	\$	<b>2,652</b>	\$	1,505	\$	881
Less: Blending and feedstock costs		<b>2,384</b>		1,309		695
Transportation	\$	<b>268</b>	\$	196	\$	186
Transportation (\$/bbl)	\$	<b>1.71</b>	\$	1.21	\$	1.23

(1) Crude oil and NGLs sales in note 22 to the Company's audited consolidated financial statements.

(2) Excludes other miscellaneous income not pertaining to crude oil and NGLs sales.

(3) Transportation, blending and feedstock in note 22 to the Company's audited consolidated financial statements.

## NET CAPITAL EXPENDITURES

Net capital expenditures is a non-GAAP financial measure that represents cash flows used in investing activities as presented in the Company's audited consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, proceeds from investments, the repayment of NWRP subordinated debt advances, abandonment expenditures including the impact of government grant income under the provincial well-site rehabilitation programs, and the settlement of long-term debt assumed in acquisitions. The Company considers net capital expenditures a key measure in evaluating its performance, as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. A reconciliation of net capital expenditures is presented below.

(\$ millions)	2022		2021		2020	
Cash flows used in investing activities	\$	<b>4,987</b>	\$	3,703	\$	2,819
Net change in non-cash working capital		<b>149</b>		107		(383)
Proceeds from investment		—		128		—
Repayment of NWRP subordinated debt advances		—		555		124
Capital expenditures		<b>5,136</b>		4,493		2,560
Abandonment expenditures, net <sup>(1)</sup>		<b>335</b>		232		249
Settlement of long-term debt acquired <sup>(2)</sup>		—		183		397
Net capital expenditures <sup>(3)</sup>	\$	<b>5,471</b>	\$	4,908	\$	3,206

(1) Non-GAAP Financial Measure. A reconciliation of abandonment expenditures, net is presented in the "Abandonment Expenditures, net" section above.

(2) Relates to the settlement of long-term debt assumed in the acquisition of Storm in 2021 and Painted Pony in 2020.

(3) For 2022, includes base capital expenditures of \$3,956 million, net property, plant and equipment acquisitions and net exploration and evaluation asset dispositions of \$470 million, and strategic growth capital expenditures of \$1,045 million. Strategic growth capital expenditures represent the allocation of the Company's free cash flow that will be directed to strategic capital growth opportunities that target to increase production volumes in future periods and that exceed the Company's base capital expenditures for the current fiscal year, as outlined in the Company's capital budget.

## LIQUIDITY

Liquidity is a non-GAAP financial measure that represents the availability of readily available undrawn bank credit facilities, cash and cash equivalents, and other highly liquid assets to meet short-term funding requirements and to assist in assessing the Company's financial position. The Company's calculation of liquidity is presented below.

(\$ millions)	2022		2021		2020
Undrawn bank credit facilities	\$	5,520	\$	6,098	\$ 4,958
Cash and cash equivalents		920		744	184
Investments		491		309	305
Liquidity	\$	6,931	\$	7,151	\$ 5,447

## LONG-TERM DEBT, NET

Long-term debt, net, is a capital management measure that represents long-term debt less cash and cash equivalents, as disclosed in note 16 to the Company's audited consolidated financial statements.

## DEBT TO BOOK CAPITALIZATION

Debt to book capitalization is a capital management measure intended to enable financial statement users to evaluate the Company's capital structure, as disclosed in note 16 to the Company's audited consolidated financial statements.

## AFTER-TAX RETURN ON AVERAGE CAPITAL EMPLOYED

After-tax return on average capital employed as defined by the Company is a non-GAAP ratio. The ratio is calculated as net earnings (loss) plus after-tax interest and other financing expense for the twelve month trailing period; as a percentage of average capital employed (defined as current and long-term debt plus shareholders' equity) for the twelve month trailing period. The Company considers this ratio a key measure in evaluating the Company's ability to generate profit and the efficiency with which it employs capital. A reconciliation of the Company's after-tax return on average capital employed is presented below.

(\$ millions, except ratios)	2022		2021		2020
Interest adjusted after-tax return:					
Net earnings (loss), 12 months trailing	\$	10,937	\$	7,664	\$ (435)
Interest and other financing expense, net of tax, 12 months trailing <sup>(1)</sup>		424		547	571
Interest adjusted after-tax return	\$	11,361	\$	8,211	\$ 136
12 months average current portion long-term debt <sup>(2)</sup>	\$	1,359	\$	1,483	\$ 1,842
12 months average long-term debt <sup>(2)</sup>		11,761		16,769	20,162
12 months average common shareholders' equity <sup>(2)</sup>		38,218		34,458	33,026
12 months average capital employed	\$	51,338	\$	52,710	\$ 55,030
After-tax return on average capital employed		22%		16%	—%

(1) The blended tax rate on interest was 23% for December 31, 2022, 23% for December 31, 2021, and 24% for December 31, 2020.

(2) For the purpose of this non-GAAP ratio, the measurement of average current and long-term debt and common shareholders equity are determined on a consistent basis, as an average of the opening and quarterly period end values for the 12 month trailing period for each of the periods presented.

## Outlook

The Company continues to implement its strategy of maintaining a large portfolio of varied projects, which the Company believes will enable it, over an extended period of time, to provide consistent growth in production and create shareholder value. Annual budgets are developed, scrutinized throughout the year and revised if necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas.

### 2023 CAPITAL BUDGET

On November 30, 2022, the Company announced its 2023 base capital budget targeted at approximately \$4,190 million. The budget also includes incremental strategic growth capital of approximately \$1,020 million that targets to add additional production and capacity growth beyond 2023 in the Company's E&P segments, and long life low decline thermal in situ and Oil Sands Mining and Upgrading assets. The 2023 capital budget constitutes forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

## Other

### SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flows from operating activities and net earnings due to changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2022, excluding mark-to-market gains (losses) on risk management activities and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	<b>Cash flows from Operating Activities</b> (\$ millions)	<b>Cash flows from Operating Activities</b> (per common share, basic)	<b>Net earnings (loss)</b> (\$ millions)	<b>Net earnings (loss)</b> (per common share, basic)
<b>Price changes</b>				
Crude oil – WTI US\$1.00/bbl				
Excluding financial derivatives	\$ 300	\$ 0.26	\$ 300	\$ 0.26
Natural gas – AECO C\$0.10/Mcf				
Excluding financial derivatives	\$ 36	\$ 0.03	\$ 36	\$ 0.03
Including financial derivatives	\$ 35	\$ 0.03	\$ 35	\$ 0.03
<b>Volume changes</b>				
Crude oil – 10,000 bbl/d	\$ 165	\$ 0.15	\$ 140	\$ 0.12
Natural gas – 10 MMcf/d	\$ 11	\$ 0.01	\$ 7	\$ 0.01
<b>Foreign currency rate change</b>				
\$0.01 change in US\$ <sup>(1)</sup>				
Including financial derivatives	\$ 280	\$ 0.25	\$ 146	\$ 0.13
<b>Interest rate change – 1%</b>	\$ 4	\$ —	\$ 4	\$ —

(1) For details of financial instruments in place, refer to note 19 to the Company's audited consolidated financial statements as at December 31, 2022.

## DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2022	2021	2020
<b>Crude oil and NGLs</b> (bbl/d)							
North America – Exploration and Production	484,280	477,478	471,632	486,559	479,971	472,621	460,443
North America – Oil Sands Mining and Upgrading <sup>(1)</sup>	429,826	356,953	487,553	428,784	425,945	448,133	417,351
International							
North Sea	15,961	10,788	10,855	14,006	12,890	17,633	23,142
Offshore Africa	15,742	15,119	13,638	12,909	14,343	14,017	17,022
Total International	31,703	25,907	24,493	26,915	27,233	31,650	40,164
Total Crude oil and NGLs	945,809	860,338	983,678	942,258	933,149	952,404	917,958
<b>Natural gas</b> (MMcf/d) <sup>(2)</sup>							
North America	1,988	2,089	2,117	2,105	2,075	1,680	1,450
International							
North Sea	3	2	1	3	2	3	12
Offshore Africa	15	14	14	7	13	12	15
Total International	18	16	15	10	15	15	27
Total Natural gas	2,006	2,105	2,132	2,115	2,090	1,695	1,477
<b>Barrels of oil equivalent</b> (BOE/d)							
North America – Exploration and Production	815,632	825,664	824,358	837,348	825,806	752,620	702,168
North America – Oil Sands Mining and Upgrading <sup>(1)</sup>	429,826	356,953	487,553	428,784	425,945	448,133	417,351
International							
North Sea	16,435	11,103	11,072	14,526	13,273	18,203	25,095
Offshore Africa	18,287	17,427	15,957	14,021	16,410	15,950	19,522
Total International	34,722	28,530	27,029	28,547	29,683	34,153	44,617
Total Barrels of oil equivalent	1,280,180	1,211,147	1,338,940	1,294,679	1,281,434	1,234,906	1,164,136

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

(2) Natural gas production volumes approximate sales volumes.

## PER UNIT RESULTS – EXPLORATION AND PRODUCTION

	Q1	Q2	Q3	Q4	2022	2021	2020
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>							
Realized price <sup>(2)</sup>	\$ 93.54	\$ 115.26	\$ 84.91	\$ 69.34	\$ 90.64	\$ 63.71	\$ 31.90
Transportation <sup>(2)</sup>	4.18	4.13	4.10	4.11	4.13	3.86	3.85
Realized price, net of transportation <sup>(2)</sup>	89.36	111.13	80.81	65.23	86.51	59.85	28.05
Royalties <sup>(3)</sup>	17.80	25.01	19.48	13.56	18.91	8.59	2.59
Production expense <sup>(4)</sup>	15.80	19.58	16.86	20.37	18.17	14.71	12.42
Netback <sup>(2)</sup>	\$ 55.76	\$ 66.54	\$ 44.47	\$ 31.30	\$ 49.43	\$ 36.55	\$ 13.04
<b>Natural gas (\$/Mcf) <sup>(1)</sup></b>							
Realized price <sup>(5)</sup>	\$ 5.26	\$ 7.93	\$ 6.57	\$ 6.39	\$ 6.55	\$ 4.07	\$ 2.40
Transportation <sup>(6)</sup>	0.50	0.52	0.51	0.55	0.51	0.45	0.43
Realized price, net of transportation	4.76	7.41	6.06	5.84	6.04	3.62	1.97
Royalties <sup>(3)</sup>	0.42	0.89	0.61	0.51	0.61	0.22	0.08
Production expense <sup>(4)</sup>	1.31	1.17	1.16	1.25	1.22	1.18	1.18
Netback	\$ 3.03	\$ 5.35	\$ 4.29	\$ 4.08	\$ 4.21	\$ 2.22	\$ 0.71
<b>Barrels of oil equivalent (\$/BOE) <sup>(1)</sup></b>							
Realized price <sup>(2)</sup>	\$ 69.66	\$ 88.07	\$ 66.04	\$ 56.83	\$ 70.07	\$ 49.67	\$ 26.15
Transportation <sup>(2)</sup>	3.72	3.70	3.64	3.80	3.72	3.44	3.44
Realized price, net of transportation <sup>(2)</sup>	65.94	84.37	62.40	53.03	66.35	46.23	22.71
Royalties <sup>(3)</sup>	11.88	17.03	12.88	9.31	12.75	5.98	1.89
Production expense <sup>(4)</sup>	12.70	14.44	12.68	15.17	13.76	11.98	10.67
Netback <sup>(2)</sup>	\$ 41.36	\$ 52.90	\$ 36.84	\$ 28.55	\$ 39.84	\$ 28.27	\$ 10.15

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

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

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

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

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

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

## PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING

	Q1	Q2	Q3	Q4	2022	2021	2020
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>							
Realized SCO sales price <sup>(2)</sup>	\$ 112.05	\$ 137.60	\$ 120.91	\$ 103.79	\$ 117.69	\$ 77.95	\$ 43.98
Bitumen royalties <sup>(3)</sup>	13.51	31.63	24.87	14.48	20.71	6.62	0.51
Transportation <sup>(2)</sup>	1.55	2.05	1.55	1.80	1.71	1.21	1.23
Production expense <sup>(4)</sup>	24.60	33.76	22.35	25.48	26.04	20.91	20.46
Netback <sup>(2)</sup>	\$ 72.39	\$ 70.16	\$ 72.14	\$ 62.03	\$ 69.23	\$ 49.21	\$ 21.78

(1) For SCO sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

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

(3) Calculated as royalties divided by sales volumes.

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

## TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2022	2021
<b>TSX – C\$</b>						
Trading volume (thousands)	408,106	378,433	401,112	346,071	1,533,722	1,568,872
Share Price (\$/share)						
High	\$ 80.13	\$ 88.18	\$ 75.95	\$ 84.25	\$ 88.18	\$ 55.59
Low	\$ 54.20	\$ 64.20	\$ 58.75	\$ 66.42	\$ 54.20	\$ 28.67
Close	\$ 77.41	\$ 69.17	\$ 64.30	\$ 75.19	\$ 75.19	\$ 53.45
Market capitalization as at December 31 (\$ millions)					\$ 82,907	\$ 62,449
Shares outstanding (thousands)					1,102,636	1,168,369
<b>NYSE – US\$</b>						
Trading volume (thousands)	243,414	176,133	187,207	148,968	755,722	795,605
Share Price (\$/share)						
High	\$ 64.10	\$ 70.60	\$ 58.60	\$ 62.57	\$ 70.60	\$ 44.33
Low	\$ 42.32	\$ 49.37	\$ 44.45	\$ 48.43	\$ 42.32	\$ 22.40
Close	\$ 61.98	\$ 53.68	\$ 46.57	\$ 55.53	\$ 55.53	\$ 42.25
Market capitalization as at December 31 (\$ millions)					\$ 61,229	\$ 49,364
Shares outstanding (thousands)					1,102,636	1,168,369