



**Canadian Natural**

**Canadian Natural Resources Limited**

**MANAGEMENT'S DISCUSSION AND ANALYSIS**

**FOR THE THREE MONTHS AND YEAR ENDED DECEMBER 31, 2021**

## MANAGEMENT'S DISCUSSION AND ANALYSIS

### 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 Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), the Oil Sands Pathway to Net Zero Initiative, 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, natural gas liquids ("NGLs") or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market; the development and deployment of technology and technological innovations; and the financial capacity of the Company to complete its growth projects and responsibly and sustainably grow in the long-term, also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

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

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of effects of the novel coronavirus ("COVID-19") pandemic and the actions of the Organization of the Petroleum Exporting Countries Plus ("OPEC+")) which may impact, among other things, demand and supply for and market prices of the Company's products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil and natural gas and NGLs prices including due to actions of OPEC+ taken in response to COVID-19 or otherwise; fluctuations in currency and interest rates; assumptions on which the Company's current targets are based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities (including any production curtailments mandated by the Government of Alberta); government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short, medium, and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

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

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

### **Special Note Regarding Non-GAAP and Other Financial Measures**

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

### **Special Note Regarding Currency, Financial Information and Production**

This MD&A should be read in conjunction with the Company's unaudited interim consolidated financial statements (the "financial statements") for the three months and year ended December 31, 2021 and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2020. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's financial statements for the three months and year ended December 31, 2021 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Production volumes and per unit statistics 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 financial results for the three months and year ended December 31, 2021 in relation to the comparable periods in 2020 and the third quarter of 2021. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2020, 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 2, 2022.

## FINANCIAL HIGHLIGHTS

(\$ millions, except per common share amounts)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Product sales <sup>(1)</sup>	\$ 10,190	\$ 8,521	\$ 5,219	\$ 32,854	\$ 17,491
Crude oil and NGLs	\$ 8,979	\$ 7,607	\$ 4,592	\$ 29,256	\$ 15,579
Natural gas	\$ 958	\$ 694	\$ 496	\$ 2,716	\$ 1,478
Net earnings (loss)	\$ 2,534	\$ 2,202	\$ 749	\$ 7,664	\$ (435)
Per common share – basic	\$ 2.16	\$ 1.87	\$ 0.63	\$ 6.49	\$ (0.37)
– diluted	\$ 2.14	\$ 1.86	\$ 0.63	\$ 6.46	\$ (0.37)
Adjusted net earnings (loss) from operations <sup>(2)</sup>	\$ 2,626	\$ 2,095	\$ 176	\$ 7,420	\$ (756)
Per common share – basic <sup>(3)</sup>	\$ 2.24	\$ 1.78	\$ 0.15	\$ 6.28	\$ (0.64)
– diluted <sup>(3)</sup>	\$ 2.21	\$ 1.77	\$ 0.15	\$ 6.25	\$ (0.64)
Cash flows from operating activities	\$ 4,712	\$ 4,290	\$ 1,270	\$ 14,478	\$ 4,714
Adjusted funds flow <sup>(2)</sup>	\$ 4,338	\$ 3,634	\$ 1,708	\$ 13,733	\$ 5,200
Per common share – basic <sup>(3)</sup>	\$ 3.69	\$ 3.08	\$ 1.45	\$ 11.63	\$ 4.40
– diluted <sup>(3)</sup>	\$ 3.66	\$ 3.07	\$ 1.44	\$ 11.57	\$ 4.40
Cash flows used in investing activities	\$ 1,615	\$ 721	\$ 624	\$ 3,703	\$ 2,819
Net capital expenditures <sup>(2)</sup>	\$ 1,804	\$ 1,011	\$ 1,176	\$ 4,908	\$ 3,206

(1) Further details related to product sales are disclosed in note 17 to the 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.

## SUMMARY OF FINANCIAL HIGHLIGHTS

### Consolidated Net Earnings (Loss) and Adjusted Net Earnings (Loss) from Operations

Net earnings for the year ended December 31, 2021 were \$7,664 million compared with a net loss of \$435 million for the year ended December 31, 2020. Net earnings for the year ended December 31, 2021 included non-operating items (after-tax) of \$244 million compared with \$321 million for the year ended December 31, 2020 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of a realized foreign exchange loss on repayment of US dollar debt securities, the realized foreign exchange gain on the settlement of the cross currency swaps, the gain on acquisitions, the (gain) loss from investments, government grant income under the provincial well-site rehabilitation programs, and a provision relating to the Keystone XL pipeline project. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2021 were \$7,420 million compared with an adjusted net loss from operations of \$756 million for the year ended December 31, 2020.

Net earnings for the fourth quarter of 2021 were \$2,534 million compared with \$749 million for the fourth quarter of 2020 and \$2,202 million for the third quarter of 2021. Net earnings for the fourth quarter of 2021 included non-operating items (after-tax) of \$92 million compared with \$573 million for the fourth quarter of 2020 and \$107 million for the third quarter of 2021 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of a realized foreign exchange loss on repayment of US dollar debt securities, the gain on acquisitions, the (gain) loss from investments, government grant income under the provincial well-site rehabilitation programs, and a provision relating to the Keystone XL pipeline project. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2021 were \$2,626 million compared with \$176 million for the fourth quarter of 2020 and \$2,095 million for the third quarter of 2021.

Net earnings and adjusted net earnings from operations for the year ended December 31, 2021 compared with a net loss and an adjusted net loss from operations for the year ended December 31, 2020 primarily reflected:

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

Net earnings and adjusted net earnings from operations for the fourth quarter of 2021 compared with net earnings and adjusted net earnings from operations for the fourth quarter of 2020 and the third quarter of 2021 primarily reflected:

- higher realized SCO sales price in the Oil Sands Mining and Upgrading segment;
- higher crude oil and NGLs netbacks and natural gas netbacks in the Exploration and Production segments;
- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment; and
- higher natural gas sales volumes in the North America segment.

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

### **Cash Flows from Operating Activities and Adjusted Funds Flow**

Cash flows from operating activities for the year ended December 31, 2021 were \$14,478 million compared with \$4,714 million for the year ended December 31, 2020. Cash flows from operating activities for the fourth quarter of 2021 were \$4,712 million compared with \$1,270 million for the fourth quarter of 2020 and \$4,290 million for the third quarter of 2021. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors previously noted related to the fluctuations in net earnings (loss) from operations, as well as due to the impact of changes in non-cash working capital, and excluding the impact of depletion, depreciation and amortization expense.

Adjusted funds flow for the year ended December 31, 2021 was \$13,733 million compared with \$5,200 million for the year ended December 31, 2020. Adjusted funds flow for the fourth quarter of 2021 was \$4,338 million compared with \$1,708 million for the fourth quarter of 2020 and \$3,634 million for the third quarter of 2021. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above related to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment expenditures excluding the impact of government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets, including the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to NWRP, and prepaid cost of service tolls.

### **Production Volumes**

Crude oil and NGLs production before royalties for the fourth quarter of 2021 increased 8% to 1,004,425 bbl/d, from 927,190 bbl/d for the fourth quarter of 2020 and increased 5% from 952,839 bbl/d for the third quarter of 2021. Natural gas production before royalties for the fourth quarter of 2021 increased 13% to 1,857 MMcf/d from 1,644 MMcf/d for the fourth quarter of 2020 and increased 9% from 1,708 MMcf/d for the third quarter of 2021. Total production before royalties for the fourth quarter of 2021 of 1,313,900 BOE/d increased 9% from 1,201,198 BOE/d for the fourth quarter of 2020 and increased 6% from 1,237,503 BOE/d for the third quarter of 2021. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production, before royalties" section of this MD&A.

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

## Product Prices

In the Company's Exploration and Production segments, realized crude oil and NGLs prices <sup>(1)</sup> averaged \$72.81 per bbl for the fourth quarter of 2021, an increase of 80% compared with \$40.56 per bbl for the fourth quarter of 2020, and an increase of 7% from \$68.06 per bbl for the third quarter of 2021. The realized natural gas price <sup>(1)</sup> increased 82% to average \$5.35 per Mcf for the fourth quarter of 2021 from \$2.94 per Mcf for the fourth quarter of 2020, and increased 30% from \$4.13 per Mcf for the third quarter of 2021. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price increased 82% to average \$88.48 per bbl for the fourth quarter of 2021 from \$48.56 per bbl for the fourth quarter of 2020, and increased 9% from \$81.54 per bbl for the third quarter of 2021. The Company's realized pricing reflects prevailing benchmark pricing. Crude oil and NGLs and natural gas prices are discussed in detail in the "Business Environment", "Realized Product Prices – Exploration and Production", and the "Oil Sands Mining and Upgrading" sections of this MD&A.

## Production Expense

In the Company's Exploration and Production segments, crude oil and NGLs production expense <sup>(2)</sup> averaged \$15.70 per bbl for the fourth quarter of 2021, an increase of 26% from \$12.47 per bbl for the fourth quarter of 2020, and an increase of 6% from \$14.78 per bbl for the third quarter of 2021. Natural gas production expense <sup>(2)</sup> averaged \$1.12 per Mcf for the fourth quarter of 2021, comparable with \$1.10 per Mcf for the fourth quarter of 2020 and a decrease of 4% from \$1.17 per Mcf for the third quarter of 2021. In the Oil Sands Mining and Upgrading segment, production costs <sup>(2)</sup> averaged \$19.55 per bbl for the fourth quarter of 2021, a decrease of 3% from \$20.20 per bbl for the fourth quarter of 2020, and comparable with \$19.86 per bbl for the third quarter of 2021. Crude oil and NGLs and natural gas production expense is discussed in detail in the "Production Expense – 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)	Dec 31 2021	Sep 30 2021	Jun 30 2021	Mar 31 2021
Product sales <sup>(1)</sup>	\$ 10,190	\$ 8,521	\$ 7,124	\$ 7,019
Crude oil and NGLs	\$ 8,979	\$ 7,607	\$ 6,382	\$ 6,288
Natural gas	\$ 958	\$ 694	\$ 509	\$ 555
Net earnings (loss)	\$ 2,534	\$ 2,202	\$ 1,551	\$ 1,377
Net earnings (loss) per common share				
– basic	\$ 2.16	\$ 1.87	\$ 1.31	\$ 1.16
– diluted	\$ 2.14	\$ 1.86	\$ 1.30	\$ 1.16
(\$ millions, except per common share amounts)	Dec 31 2020	Sep 30 2020	Jun 30 2020	Mar 31 2020
Product sales <sup>(1)</sup>	\$ 5,219	\$ 4,676	\$ 2,944	\$ 4,652
Crude oil and NGLs	\$ 4,592	\$ 4,202	\$ 2,462	\$ 4,323
Natural gas	\$ 496	\$ 338	\$ 307	\$ 337
Net earnings (loss)	\$ 749	\$ 408	\$ (310)	\$ (1,282)
Net earnings (loss) per common share				
– basic	\$ 0.63	\$ 0.35	\$ (0.26)	\$ (1.08)
– diluted	\$ 0.63	\$ 0.35	\$ (0.26)	\$ (1.08)

(1) Further details related to product sales for the three months ended December 31, 2021 and 2020 are disclosed in note 17 to the financial statements.

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

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

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

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

## **BUSINESS ENVIRONMENT**

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

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

### **Liquidity**

As at December 31, 2021, the Company had undrawn bank credit facilities of \$6,098 million. Including cash and cash equivalents and short-term investments, the Company had approximately \$7,151 million in liquidity <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 January 11, 2022, the Company announced its 2022 base capital budget <sup>(2)</sup> targeted at approximately \$3,645 million. The budget also includes incremental strategic growth capital of approximately \$700 million that targets to add future production and capacity in the Company's long life low decline thermal in situ and Oil Sands Mining and Upgrading assets. Production for 2022 is targeted between 1,270,000 BOE/d and 1,320,000 BOE/d. Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, in the context of price volatility, project returns and the balancing of project risks and time horizons. The 2022 capital budget and production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

On December 9, 2020, the Company announced its 2021 capital budget targeted at approximately \$3,205 million, and on August 5, 2021, the 2021 capital budget was increased to approximately \$3,480 million, excluding acquisitions. Net capital expenditures for the year ended December 31, 2021 were \$4,908 million, including the impact of acquisitions. Refer to the "Net Capital Expenditures" section of this MD&A for further details on the 2021 net capital expenditures.

On December 17, 2021, the Company completed the acquisition of all the issued and outstanding common shares of Storm Resources Limited ("Storm") for total cash consideration of approximately \$771 million. At closing, the acquisition also included the assumption of long-term debt of approximately \$183 million. Storm is involved in the exploration for and development of natural gas and natural gas liquids in the Montney region of British Columbia.

During the year ended December 31, 2021, the Company also completed a number of other opportunistic acquisitions. Two acquisitions consisted of natural gas assets located in the Montney region of British Columbia, with aggregate production of approximately 11,100 BOE/d. A third acquisition consisted of a net carried interest on an existing oil sands lease held by the Company, from which all Horizon production volumes are derived. Total cash consideration paid for these acquisitions was approximately \$450 million.

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

### **Risks and Uncertainties**

COVID-19, including variants of concern, continues to have the potential to further disrupt the Company's operations, projects and financial condition through the disruption of the local or global supply chain and transportation services, or the loss of manpower resulting from quarantines that affect the Company's labour pools in their local communities, workforce camps or operating sites or that are instituted by local health authorities as a precautionary measure, any of which may require the Company to temporarily reduce or shutdown its operations depending on their extent and severity.

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

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

## Benchmark Commodity Prices

(Average for the period)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
WTI benchmark price (US\$/bbl)	\$ 77.17	\$ 70.55	\$ 42.67	\$ 67.96	\$ 39.40
Dated Brent benchmark price (US\$/bbl)	\$ 79.55	\$ 72.98	\$ 44.52	\$ 70.49	\$ 42.27
WCS Heavy Differential from WTI (US\$/bbl)	\$ 14.65	\$ 13.58	\$ 9.30	\$ 13.04	\$ 12.57
SCO price (US\$/bbl)	\$ 75.39	\$ 68.98	\$ 39.69	\$ 66.36	\$ 36.26
Condensate benchmark price (US\$/bbl)	\$ 79.10	\$ 69.22	\$ 42.54	\$ 68.24	\$ 36.97
Condensate Differential from WTI (US\$/bbl)	\$ (1.93)	\$ 1.33	\$ 0.13	\$ (0.28)	\$ 2.43
NYMEX benchmark price (US\$/MMBtu)	\$ 5.83	\$ 4.01	\$ 2.66	\$ 3.85	\$ 2.08
AECO benchmark price (C\$/GJ)	\$ 4.67	\$ 3.36	\$ 2.62	\$ 3.38	\$ 2.12
US/Canadian dollar average exchange rate (US\$)	\$ 0.7937	\$ 0.7936	\$ 0.7674	\$ 0.7979	\$ 0.7454

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

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US\$67.96 per bbl for the year ended December 31, 2021, an increase of 72% from US\$39.40 per bbl for the year ended December 31, 2020. WTI averaged US\$77.17 per bbl for the fourth quarter of 2021, an increase of 81% from US\$42.67 per bbl for the fourth quarter of 2020, and an increase of 9% from US\$70.55 per bbl for the third quarter of 2021.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US\$70.49 per bbl for the year ended December 31, 2021, an increase of 67% from US\$42.27 per bbl for the year ended December 31, 2020. Brent averaged US\$79.55 per bbl for the fourth quarter of 2021, an increase of 79% from US\$44.52 per bbl for the fourth quarter of 2020, and an increase of 9% from US\$72.98 per bbl for the third quarter of 2021.

The increase in WTI and Brent pricing for the three months and year ended December 31, 2021 from the comparable periods in 2020 primarily reflected the OPEC+ decision to adhere to the previously agreed upon production cut agreements. Additionally, global demand for crude oil increased due to improved economic conditions as a result of the lessening of earlier COVID-19 restrictions. The increase in WTI and Brent pricing for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected the continued recovery of global demand.

The WCS Heavy Differential averaged US\$13.04 per bbl for the year ended December 31, 2021, a slight widening of 4% from US\$12.57 per bbl for the year ended December 31, 2020. The WCS Heavy Differential averaged US\$14.65 per bbl for the fourth quarter of 2021, a widening of 58% from US\$9.30 per bbl for the fourth quarter of 2020, and a widening of 8% from US\$13.58 per bbl for the third quarter of 2021. The widening of the WCS Heavy Differential for the fourth quarter of 2021 from the comparable periods primarily reflected the increase in WTI benchmark pricing and the widening of the US Gulf Coast heavy oil pricing.

The SCO price averaged US\$66.36 per bbl for the year ended December 31, 2021, an increase of 83% from US\$36.26 per bbl for the year ended December 31, 2020. The SCO price averaged US\$75.39 per bbl for the fourth quarter of 2021, an increase of 90% from US\$39.69 per bbl for the fourth quarter of 2020, and an increase of 9% from US\$68.98 per bbl for the third quarter of 2021. The increase in SCO pricing for the three months and year ended December 31, 2021 from the comparable periods primarily reflected the increase in WTI benchmark pricing.

NYMEX natural gas prices averaged US\$3.85 per MMBtu for the year ended December 31, 2021, an increase of 85% from US\$2.08 per MMBtu for the year ended December 31, 2020. NYMEX natural gas prices averaged US\$5.83 per MMBtu for the fourth quarter of 2021, an increase of \$3.17 per MMBtu from US\$2.66 per MMBtu for the fourth quarter of 2020, and an increase of 45% from US\$4.01 per MMBtu for the third quarter of 2021. The increase in NYMEX natural gas prices for the three months and year ended December 31, 2021 from the comparable periods in 2020 primarily reflected increased North American demand in 2021, following the impact of COVID-19 in 2020, as well as lower storage levels. The increase in NYMEX natural gas prices for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected increased US Liquefied Natural Gas ("LNG") exports resulting from higher global LNG prices, together with low storage levels.

AECO natural gas prices averaged \$3.38 per GJ for the year ended December 31, 2021, an increase of 59% from \$2.12 per GJ for the year ended December 31, 2020. AECO natural gas prices averaged \$4.67 per GJ for the fourth quarter of 2021, an increase of 78% from \$2.62 per GJ for the fourth quarter of 2020, and an increase of 39% from \$3.36 per GJ for the third quarter of 2021. The increase in AECO natural gas prices for the three months and year ended December 31, 2021 from the comparable periods primarily reflected lower storage levels and increased NYMEX benchmark pricing.

### DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
<b>Crude oil and NGLs (bbl/d)</b>					
North America – Exploration and Production	<b>478,738</b>	454,888	475,889	<b>472,621</b>	460,443
North America – Oil Sands Mining and Upgrading <sup>(1)</sup>	<b>493,406</b>	468,126	417,089	<b>448,133</b>	417,351
North Sea	<b>17,860</b>	16,294	17,057	<b>17,633</b>	23,142
Offshore Africa	<b>14,421</b>	13,531	17,155	<b>14,017</b>	17,022
	<b>1,004,425</b>	952,839	927,190	<b>952,404</b>	917,958
<b>Natural gas (MMcf/d) <sup>(2)</sup></b>					
North America	<b>1,841</b>	1,698	1,623	<b>1,680</b>	1,450
North Sea	<b>3</b>	2	4	<b>3</b>	12
Offshore Africa	<b>13</b>	8	17	<b>12</b>	15
	<b>1,857</b>	1,708	1,644	<b>1,695</b>	1,477
<b>Total barrels of oil equivalent (BOE/d)</b>	<b>1,313,900</b>	1,237,503	1,201,198	<b>1,234,906</b>	1,164,136
<b>Product mix</b>					
Light and medium crude oil and NGLs	<b>10%</b>	10%	10%	<b>10%</b>	11%
Pelican Lake heavy crude oil	<b>4%</b>	4%	5%	<b>5%</b>	5%
Primary heavy crude oil	<b>5%</b>	5%	5%	<b>5%</b>	6%
Bitumen (thermal oil)	<b>20%</b>	20%	22%	<b>21%</b>	21%
Synthetic crude oil <sup>(1)</sup>	<b>38%</b>	38%	35%	<b>36%</b>	36%
Natural gas	<b>23%</b>	23%	23%	<b>23%</b>	21%
<b>Percentage of gross revenue <sup>(1) (3)</sup></b> (excluding Midstream and Refining revenue)					
Crude oil and NGLs	<b>90%</b>	91%	90%	<b>91%</b>	91%
Natural gas	<b>10%</b>	9%	10%	<b>9%</b>	9%

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

(2) Natural gas production volumes approximate sales volumes.

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

## DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
<b>Crude oil and NGLs (bbl/d)</b>					
North America – Exploration and Production	<b>403,305</b>	386,416	433,697	<b>404,637</b>	420,906
North America – Oil Sands Mining and Upgrading	<b>440,492</b>	421,483	411,640	<b>410,385</b>	413,363
North Sea	<b>17,825</b>	16,256	17,023	<b>17,588</b>	23,086
Offshore Africa	<b>13,638</b>	12,901	16,416	<b>13,354</b>	16,306
	<b>875,260</b>	837,056	878,776	<b>845,964</b>	873,661
<b>Natural gas (MMcf/d)</b>					
North America	<b>1,721</b>	1,609	1,553	<b>1,593</b>	1,406
North Sea	<b>3</b>	2	4	<b>3</b>	12
Offshore Africa	<b>12</b>	7	16	<b>11</b>	14
	<b>1,736</b>	1,618	1,573	<b>1,607</b>	1,432
Total barrels of oil equivalent (BOE/d)	<b>1,164,613</b>	1,106,743	1,141,022	<b>1,113,878</b>	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.

Record crude oil and NGLs production before royalties for the year ended December 31, 2021 averaged 952,404 bbl/d, an increase of 4% from 917,958 bbl/d for the year ended December 31, 2020. Crude oil and NGLs production for the fourth quarter of 2021 averaged 1,004,425 bbl/d, an increase of 8% from 927,190 bbl/d for the fourth quarter of 2020, and an increase of 5% from 952,839 bbl/d for the third quarter of 2021. The increase in crude oil and NGLs production for the year ended December 31, 2021 from 2020 and for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected strong operational performance in the Oil Sands Mining and Upgrading segment and increased thermal oil production. The increase in crude oil and NGLs production for the fourth quarter of 2021 from the fourth quarter of 2020 primarily reflected strong operational performance in the Oil Sands Mining and Upgrading segment, together with the timing of turnaround activities. Crude oil and NGLs production in North America Exploration and Production and Oil Sands Mining and Upgrading segments for 2021 as compared with 2020 reflected the impact of the Company's curtailment optimization strategy during mandatory Government of Alberta curtailment.

Annual crude oil and NGLs production for 2021 was within the Company's previously issued target of 940,000 bbl/d and 980,000 bbl/d. Annual crude oil and NGLs production for 2022 is targeted to average between 940,000 bbl/d and 982,000 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 for the year ended December 31, 2021 of 1,695 MMcf/d increased 15% from 1,477 MMcf/d for the year ended December 31, 2020. Record natural gas production for the fourth quarter of 2021 of 1,857 MMcf/d increased 13% from 1,644 MMcf/d for the fourth quarter of 2020, and increased 9% from 1,708 MMcf/d for the third quarter of 2021. The increase in natural gas production for the three months and year ended December 31, 2021 from the comparable periods primarily reflected strong drilling results and production volumes from acquisitions, partially offset by natural field declines.

Annual natural gas production for 2021 was within the Company's previously issued target of 1,680 MMcf/d and 1,720 MMcf/d. Annual natural gas production for 2022 is targeted to average between 1,980 MMcf/d and 2,030 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 the year ended December 31, 2021 averaged 472,621 bbl/d, an increase of 3% from 460,443 bbl/d for the year ended December 31, 2020. North America crude oil and NGLs production for the fourth quarter of 2021 of 478,738 bbl/d was comparable with 475,889 bbl/d for the fourth quarter of 2020, and increased 5% from 454,888 bbl/d for the third quarter of 2021. The increase in crude oil and NGLs production for the year ended December 31, 2021 from 2020 and for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected increased thermal oil production and strong drilling results, partially offset by natural field declines.

Thermal oil production before royalties for the fourth quarter of 2021 averaged 263,110 bbl/d, comparable with 266,179 bbl/d for the fourth quarter of 2020, and an increase of 6% from 248,113 bbl/d for the third quarter of 2021. The increase in thermal oil production for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected the completion of planned turnaround activities at Jackfish.

Pelican Lake heavy crude oil production before royalties averaged 52,963 bbl/d for the fourth quarter of 2021, a decrease of 5% from 56,036 bbl/d for the fourth quarter of 2020, and was comparable with 53,923 bbl/d for the third quarter of 2021, demonstrating Pelican Lake's long life low decline production.

Natural gas production before royalties for the year ended December 31, 2021 averaged 1,680 MMcf/d, an increase of 16% from 1,450 MMcf/d for the year ended December 31, 2020. Natural gas production for the fourth quarter of 2021 averaged 1,841 MMcf/d, an increase of 13% from 1,623 MMcf/d for the fourth quarter of 2020, and an increase of 8% from 1,698 MMcf/d for the third quarter of 2021. The increase in natural gas production for the three months and year ended December 31, 2021 from the comparable periods primarily reflected strong drilling results and production volumes from acquisitions, partially offset by natural field declines.

## **North America – Oil Sands Mining and Upgrading**

Record SCO production before royalties for the year ended December 31, 2021 of 448,133 bbl/d increased 7% from 417,351 bbl/d for the year ended December 31, 2020. Record SCO production for the fourth quarter of 2021 of 493,406 bbl/d increased 18% from 417,089 bbl/d for the fourth quarter of 2020 and increased 5% from 468,126 bbl/d for the third quarter of 2021. The increase in SCO production for the year ended December 31, 2021 from 2020 primarily reflected strong operational performance at AOSP following the completion of expansion activities at Scotford in the prior year. The increase in SCO production for the fourth quarter of 2021 from the comparable periods primarily reflected strong operational performance and the impact of the timing of turnaround activities in 2020 and 2021.

## **North Sea**

North Sea crude oil production before royalties for the year ended December 31, 2021 of 17,633 bbl/d decreased 24% from 23,142 bbl/d for the year ended December 31, 2020. North Sea crude oil production for the fourth quarter of 2021 of 17,860 bbl/d increased 5% from 17,057 bbl/d for the fourth quarter of 2020 and increased 10% from 16,294 bbl/d for the third quarter of 2021. The decrease in production for the year ended December 31, 2021 from 2020 primarily reflected natural field declines and planned maintenance activities. The increase in production for the fourth quarter of 2021 from the comparable periods primarily reflected planned maintenance activities during the fourth quarter of 2020 and third quarter of 2021.

## **Offshore Africa**

Offshore Africa crude oil production before royalties for the year ended December 31, 2021 decreased 18% to 14,017 bbl/d from 17,022 bbl/d for the year ended December 31, 2020. Offshore Africa crude oil production for the fourth quarter of 2021 of 14,421 bbl/d decreased 16% from 17,155 bbl/d for the fourth quarter of 2020 and increased 7% from 13,531 bbl/d for the third quarter of 2021. The decrease in production for the three months and year ended December 31, 2021 from the comparable periods in 2020 primarily reflected maintenance activities and natural field declines. The increase in production for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected the completion of planned maintenance activities at Espoir in the fourth quarter.

## 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)	Dec 31 2021	Sep 30 2021	Dec 31 2020
North Sea	—	295,014	450,889
Offshore Africa	727,439	—	521,244
	727,439	295,014	972,133

## OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>					
Realized price <sup>(2)</sup>	\$ 72.81	\$ 68.06	\$ 40.56	\$ 63.71	\$ 31.90
Transportation <sup>(2)</sup>	3.93	4.00	3.81	3.86	3.85
Realized price, net of transportation <sup>(2)</sup>	68.88	64.06	36.75	59.85	28.05
Royalties <sup>(3)</sup>	10.67	9.46	3.34	8.59	2.59
Production expense <sup>(4)</sup>	15.70	14.78	12.47	14.71	12.42
Netback <sup>(2)</sup>	\$ 42.51	\$ 39.82	\$ 20.94	\$ 36.55	\$ 13.04
<b>Natural gas (\$/Mcf) <sup>(1)</sup></b>					
Realized price <sup>(5)</sup>	\$ 5.35	\$ 4.13	\$ 2.94	\$ 4.07	\$ 2.40
Transportation <sup>(6)</sup>	0.42	0.44	0.42	0.45	0.43
Realized price, net of transportation	4.93	3.69	2.52	3.62	1.97
Royalties <sup>(3)</sup>	0.35	0.22	0.13	0.22	0.08
Production expense <sup>(4)</sup>	1.12	1.17	1.10	1.18	1.18
Netback <sup>(2)</sup>	\$ 3.46	\$ 2.30	\$ 1.29	\$ 2.22	\$ 0.71
<b>Barrels of oil equivalent (\$/BOE) <sup>(1)</sup></b>					
Realized price <sup>(2)</sup>	\$ 57.72	\$ 52.09	\$ 32.61	\$ 49.67	\$ 26.15
Transportation <sup>(2)</sup>	3.40	3.50	3.37	3.44	3.44
Realized price, net of transportation <sup>(2)</sup>	54.32	48.59	29.24	46.23	22.71
Royalties <sup>(3)</sup>	7.48	6.45	2.44	5.98	1.89
Production expense <sup>(4)</sup>	12.33	11.91	10.43	11.98	10.67
Netback <sup>(2)</sup>	\$ 34.51	\$ 30.23	\$ 16.37	\$ 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

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>					
North America <sup>(2)</sup>	\$ 71.57	\$ 66.03	\$ 39.54	\$ 62.10	\$ 30.31
North Sea <sup>(3)</sup>	\$ 100.45	\$ 96.11	\$ 56.18	\$ 87.98	\$ 50.09
Offshore Africa <sup>(3)</sup>	\$ 75.42	\$ 91.73	\$ 49.05	\$ 85.71	\$ 50.95
Average <sup>(2)</sup>	\$ 72.81	\$ 68.06	\$ 40.56	\$ 63.71	\$ 31.90
<b>Natural gas (\$/Mcf) <sup>(1) (3)</sup></b>					
North America	\$ 5.33	\$ 4.12	\$ 2.91	\$ 4.05	\$ 2.34
North Sea	\$ 3.20	\$ 3.75	\$ 1.41	\$ 2.94	\$ 2.74
Offshore Africa	\$ 9.00	\$ 6.83	\$ 6.64	\$ 7.17	\$ 7.77
Average	\$ 5.35	\$ 4.13	\$ 2.94	\$ 4.07	\$ 2.40
Average (\$/BOE) <sup>(1) (2)</sup>	\$ 57.72	\$ 52.09	\$ 32.61	\$ 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 by \$31.79 per bbl to average \$62.10 per bbl for the year ended December 31, 2021 from \$30.31 per bbl for the year ended December 31, 2020. North America realized crude oil and NGLs prices increased 81% to average \$71.57 per bbl for the fourth quarter of 2021 from \$39.54 per bbl for the fourth quarter of 2020, and increased 8% from \$66.03 per bbl for the third quarter of 2021. The increase in realized crude oil and NGLs prices for the three months and year ended December 31, 2021 from the comparable periods was primarily due to higher WTI benchmark pricing. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2021 contributed approximately 173,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 73% to average \$4.05 per Mcf for the year ended December 31, 2021 from \$2.34 per Mcf for the year ended December 31, 2020. North America realized natural gas prices increased 83% to average \$5.33 per Mcf for the fourth quarter of 2021 from \$2.91 per Mcf for the fourth quarter of 2020, and increased 29% from \$4.12 per Mcf for the third quarter of 2021. The increase in realized natural gas prices for the three months and year ended December 31, 2021 from the comparable periods primarily reflected lower storage levels and increased benchmark pricing.

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

(Quarterly average)	Three Months Ended		
	Dec 31 2021	Sep 30 2021	Dec 31 2020
<b>Wellhead Price <sup>(1)</sup></b>			
Light and medium crude oil and NGLs (\$/bbl)	\$ 74.41	\$ 63.88	\$ 38.03
Pelican Lake heavy crude oil (\$/bbl)	\$ 77.40	\$ 71.92	\$ 43.21
Primary heavy crude oil (\$/bbl)	\$ 75.47	\$ 68.72	\$ 42.01
Bitumen (thermal oil) (\$/bbl)	\$ 68.45	\$ 64.81	\$ 38.67
Natural gas (\$/Mcf)	\$ 5.33	\$ 4.12	\$ 2.91

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

## North Sea

North Sea realized crude oil and NGLs prices increased 76% to average \$87.98 per bbl for the year ended December 31, 2021 from \$50.09 per bbl for the year ended December 31, 2020. North Sea realized crude oil and NGLs prices increased 79% to average \$100.45 per bbl for the fourth quarter of 2021 from \$56.18 per bbl for the fourth quarter of 2020 and increased 5% from \$96.11 per bbl for the third quarter of 2021. Realized crude oil and NGLs prices per barrel in any particular period 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 fluctuations in realized crude oil and NGLs prices for the three months and year ended December 31, 2021 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

## Offshore Africa

Offshore Africa realized crude oil and NGLs prices increased 68% to average \$85.71 per bbl for the year ended December 31, 2021 from \$50.95 per bbl for the year ended December 31, 2020. Offshore Africa realized crude oil and NGLs prices increased 54% to average \$75.42 per bbl for the fourth quarter of 2021 from \$49.05 per bbl for the fourth quarter of 2020 and decreased 18% from \$91.73 per bbl for the third quarter of 2021. Realized crude oil and NGLs prices per barrel in any particular period 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 fluctuations in realized crude oil and NGLs prices for the three months and year ended December 31, 2021 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

## ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>					
North America	\$ 11.21	\$ 10.02	\$ 3.52	\$ 9.06	\$ 2.72
North Sea	\$ 0.19	\$ 0.22	\$ 0.11	\$ 0.19	\$ 0.12
Offshore Africa	\$ 4.10	\$ 4.27	\$ 2.11	\$ 3.94	\$ 2.17
Average	\$ 10.67	\$ 9.46	\$ 3.34	\$ 8.59	\$ 2.59
<b>Natural gas (\$/Mcf) <sup>(1)</sup></b>					
North America	\$ 0.35	\$ 0.22	\$ 0.13	\$ 0.22	\$ 0.07
Offshore Africa	\$ 0.41	\$ 0.31	\$ 0.30	\$ 0.33	\$ 0.37
Average	\$ 0.35	\$ 0.22	\$ 0.13	\$ 0.22	\$ 0.08
<b>Average (\$/BOE) <sup>(1)</sup></b>	\$ 7.48	\$ 6.45	\$ 2.44	\$ 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

North America crude oil and NGLs and natural gas royalties for the three months and year ended December 31, 2021 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential and changes in the production mix between high and low royalty rate product types.

Crude oil and NGLs royalty rates <sup>(1)</sup> averaged approximately 15% of product sales for the year ended December 31, 2021 compared with 9% of product sales for the year ended December 31, 2020. Crude oil and NGLs royalty rates averaged approximately 16% of product sales for the fourth quarter of 2021 compared with 9% for the fourth quarter of 2020 and 15% for the third quarter of 2021. The increase in royalty rates for the three months and year ended December 31, 2021 from the comparable periods in 2020 was primarily due to higher benchmark prices together with fluctuations in the WCS Heavy Differential.

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

Natural gas royalty rates averaged approximately 5% of product sales for the year ended December 31, 2021 compared with 3% of product sales for the year ended December 31, 2020. Natural gas royalty rates averaged approximately 7% of product sales for the fourth quarter of 2021 compared with 4% for the fourth quarter of 2020 and 5% for the third quarter of 2021. The increase in royalty rates for the three months and year ended December 31, 2021 from the comparable periods was primarily due to higher benchmark prices.

### Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 5% for the year ended December 31, 2021, compared with 4% of product sales for the year ended December 31, 2020. Royalty rates as a percentage of product sales averaged approximately 5% for the fourth quarter of 2021 compared with 4% of product sales for the fourth quarter of 2020 and 5% for the third quarter of 2021. Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

### PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>					
North America	\$ 13.55	\$ 13.33	\$ 10.81	\$ 13.12	\$ 11.21
North Sea	\$ 64.96	\$ 55.90	\$ 52.42	\$ 54.13	\$ 36.51
Offshore Africa	\$ 16.75	\$ 14.53	\$ 11.74	\$ 14.73	\$ 13.29
Average	\$ 15.70	\$ 14.78	\$ 12.47	\$ 14.71	\$ 12.42
<b>Natural gas (\$/Mcf) <sup>(1)</sup></b>					
North America	\$ 1.08	\$ 1.14	\$ 1.07	\$ 1.15	\$ 1.14
North Sea	\$ 9.19	\$ 8.86	\$ 5.29	\$ 7.31	\$ 3.72
Offshore Africa	\$ 4.52	\$ 5.76	\$ 3.07	\$ 4.41	\$ 3.58
Average	\$ 1.12	\$ 1.17	\$ 1.10	\$ 1.18	\$ 1.18
<b>Average (\$/BOE) <sup>(1)</sup></b>	\$ 12.33	\$ 11.91	\$ 10.43	\$ 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 the year ended December 31, 2021 averaged \$13.12 per bbl, an increase of 17% from \$11.21 per bbl for the year ended December 31, 2020. North America crude oil and NGLs production expense for the fourth quarter of 2021 of \$13.55 per bbl increased 25% from \$10.81 per bbl for the fourth quarter of 2020 and was comparable with \$13.33 per bbl for the third quarter of 2021. The increase in crude oil and NGLs production expense per bbl for the three months and year ended December 31, 2021 from the comparable periods in 2020 primarily reflected increased energy costs.

North America natural gas production expense for the year ended December 31, 2021 averaged \$1.15 per Mcf, comparable with \$1.14 per Mcf for the year ended December 31, 2020. North America natural gas production expense for the fourth quarter of 2021 of \$1.08 per Mcf was comparable with \$1.07 per Mcf for the fourth quarter of 2020 and decreased 5% from \$1.14 per Mcf for the third quarter of 2021. The decrease in natural gas production expense for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected higher production volumes and the Company's strong focus on cost control.

## North Sea

North Sea crude oil production expense for the year ended December 31, 2021 averaged \$54.13 per bbl, an increase of 48% from \$36.51 per bbl for the year ended December 31, 2020. North Sea crude oil production expense for the fourth quarter of 2021 of \$64.96 per bbl increased 24% from \$52.42 per bbl for the fourth quarter of 2020 and increased 16% from \$55.90 per bbl for the third quarter of 2021. The increase in crude oil production expense per bbl for the year ended December 31, 2021 from 2020 primarily reflected lower volumes, on a relatively fixed cost base, as well as higher natural gas and CO<sub>2</sub> costs. The increase in crude oil production expense per barrel for the fourth quarter of 2021 from the comparable periods primarily reflected higher natural gas and CO<sub>2</sub> costs. North Sea production expense also reflected fluctuations in the Canadian dollar.

## Offshore Africa

Offshore Africa crude oil production expense for the year ended December 31, 2021 averaged \$14.73 per bbl, an increase of 11% from \$13.29 per bbl for the year ended December 31, 2020. Offshore Africa crude oil production expense for the fourth quarter of 2021 of \$16.75 per bbl increased 43% from \$11.74 per bbl for the fourth quarter of 2020 and increased 15% from \$14.53 per bbl for the third quarter of 2021. The increase in crude oil production expense per bbl for the three months and year ended December 31, 2021 from the comparable periods primarily reflected the timing of liftings from various fields that have different cost structures, together with lower volumes, on a relatively fixed cost base. Offshore Africa production expense also reflected fluctuations in the Canadian dollar.

## DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

(\$ millions, except per BOE amounts)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
North America	\$ 939	\$ 881	\$ 1,017	\$ 3,569	\$ 3,780
North Sea	33	40	61	160	277
Offshore Africa	19	48	54	142	190
Depletion, Depreciation and Amortization	\$ 991	\$ 969	\$ 1,132	\$ 3,871	\$ 4,247
\$/BOE <sup>(1)</sup>	\$ 13.03	\$ 13.70	\$ 15.55	\$ 13.49	\$ 15.45

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

Depletion, depreciation and amortization expense for the year ended December 31, 2021 of \$13.49 per BOE decreased 13% from \$15.45 per BOE for the year ended December 31, 2020. Depletion, depreciation and amortization expense for the fourth quarter of 2021 of \$13.03 per BOE decreased 16% from \$15.55 per BOE for the fourth quarter of 2020 and decreased 5% from \$13.70 per BOE for the third quarter of 2021. The decrease in depletion, depreciation and amortization expense per BOE for the three months and year ended December 31, 2021 from the comparable periods in 2020 primarily reflected lower depletion rates in the North America Exploration and Production segment and lower volumes in the North Sea, which has higher depletion rates. The decrease in depletion, depreciation and amortization expense per BOE for the fourth quarter of 2021 from the third quarter of 2021 primarily reflected the product mix in the North America Exploration and Production segment.

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)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
North America	\$ 25	\$ 26	\$ 24	\$ 101	\$ 97
North Sea	5	6	8	21	30
Offshore Africa	2	1	1	6	6
Asset Retirement Obligation Accretion	\$ 32	\$ 33	\$ 33	\$ 128	\$ 133
\$/BOE <sup>(1)</sup>	\$ 0.42	\$ 0.45	\$ 0.45	\$ 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 the year ended December 31, 2021 of \$0.44 per BOE decreased 8% from \$0.48 per BOE for the year ended December 31, 2020. Asset retirement obligation accretion expense for the fourth quarter of 2021 of \$0.42 per BOE decreased 7% from \$0.45 per BOE for the fourth quarter of 2020 and for the third quarter of 2021. Fluctuations in asset retirement obligation accretion expense on a per BOE basis primarily reflect fluctuating sales volumes.

## OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the Horizon and AOSP sites. Record SCO production in the fourth quarter of 2021 of 493,406 bbl/d primarily reflected strong operational performance.

The Company incurred production costs, excluding natural gas costs, of \$796 million and \$17.86 per bbl for the fourth quarter of 2021, comparable with \$802 million and a 4% decrease from \$18.63 per bbl for the third quarter of 2021, reflecting record production volumes, together with the Company's strong focus on cost control.

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

(\$/bbl)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Realized SCO sales price <sup>(1)</sup>	\$ 88.48	\$ 81.54	\$ 48.56	\$ 77.95	\$ 43.98
Bitumen value for royalty purposes <sup>(2)</sup>	\$ 65.80	\$ 62.28	\$ 34.70	\$ 58.39	\$ 25.82
Bitumen royalties <sup>(3)</sup>	\$ 9.16	\$ 8.21	\$ 0.59	\$ 6.62	\$ 0.51
Transportation <sup>(1)</sup>	\$ 1.33	\$ 1.14	\$ 1.36	\$ 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. For SCO sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

The realized SCO sales price averaged \$77.95 per bbl for the year ended December 31, 2021, an increase of 77% from \$43.98 per bbl for the year ended December 31, 2020. The realized SCO sales price averaged \$88.48 per bbl for the fourth quarter of 2021, an increase of 82% from \$48.56 per bbl for the fourth quarter of 2020 and an increase of 9% from \$81.54 per bbl for the third quarter of 2021. The increase in the realized SCO sales price for the three months and year ended December 31, 2021 from the comparable periods primarily reflected the increase in WTI benchmark pricing.

The increase in bitumen royalties per bbl for the three months and year ended December 31, 2021 from the comparable periods primarily reflected the impact of higher prevailing bitumen pricing and AOSP reaching full payout.

Transportation expense averaged \$1.21 per bbl for the year ended December 31, 2021, comparable with \$1.23 per bbl for the year ended December 31, 2020. For the fourth quarter of 2021, transportation expense of \$1.33 per bbl was comparable with \$1.36 per bbl for the fourth quarter of 2020 and increased 17% from \$1.14 per bbl for the third quarter of 2021. The increase in transportation expense per bbl for the fourth quarter of 2021 compared to the third quarter of 2021 reflected the impact of US Gulf Coast sales.

## PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 17 to the financial statements.

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Production costs, excluding natural gas costs	\$ 796	\$ 802	\$ 736	\$ 3,176	\$ 2,968
Natural gas costs	75	53	51	238	146
Production costs	\$ 871	\$ 855	\$ 787	\$ 3,414	\$ 3,114

(\$/bbl)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Production costs, excluding natural gas costs <sup>(1)</sup>	\$ 17.86	\$ 18.63	\$ 18.89	\$ 19.45	\$ 19.50
Natural gas costs <sup>(2)</sup>	1.69	1.23	1.31	1.46	0.96
Production costs <sup>(3)</sup>	\$ 19.55	\$ 19.86	\$ 20.20	\$ 20.91	\$ 20.46
Sales volumes (bbl/d)	483,972	467,772	423,438	447,230	415,741

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

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

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

Production costs for the year ended December 31, 2021 of \$20.91 per bbl were comparable with \$20.46 per bbl for the year ended December 31, 2020. Production costs for the fourth quarter of 2021 averaged \$19.55 per bbl, a decrease of 3% from \$20.20 per bbl for the fourth quarter of 2020 and was comparable with \$19.86 per bbl for the third quarter of 2021. Production costs per bbl for the year ended December 31, 2021 as compared to 2020 primarily reflected the impact of higher energy costs, including natural gas and diesel, offset by the impact of record production volumes, together with the Company's strong focus on cost control. The decrease in production costs per bbl for the fourth quarter of 2021 from the comparable period in 2020 primarily reflected record production volumes, together with the Company's strong focus on cost control.

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

(\$ millions, except per bbl amounts)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Depletion, depreciation and amortization	\$ 478	\$ 469	\$ 479	\$ 1,838	\$ 1,784
\$/bbl <sup>(1)</sup>	\$ 10.73	\$ 10.90	\$ 12.31	\$ 11.26	\$ 11.73

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

Depletion, depreciation and amortization expense for the year ended December 31, 2021 of \$11.26 per bbl decreased 4% from \$11.73 per bbl for the year ended December 31, 2020. Depletion, depreciation and amortization expense for the fourth quarter of 2021 of \$10.73 per bbl decreased 13% from \$12.31 per bbl for the fourth quarter of 2020, and was comparable with \$10.90 per bbl for the third quarter of 2021. The decrease in depletion, depreciation and amortization on a per barrel basis for the three months and year ended December 31, 2021 from the comparable periods in 2020 primarily reflected the impact of fluctuating sales volumes from underlying operations.

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

(\$ millions, except per bbl amounts)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Asset retirement obligation accretion	\$ 14	\$ 14	\$ 18	\$ 57	\$ 72
\$/bbl <sup>(1)</sup>	\$ 0.32	\$ 0.33	\$ 0.47	\$ 0.35	\$ 0.47

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

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

Asset retirement obligation accretion expense for the year ended December 31, 2021 of \$0.35 per bbl decreased 26% from \$0.47 per bbl for the year ended December 31, 2020. Asset retirement obligation accretion expense of \$0.32 per bbl for the fourth quarter of 2021 decreased 32% from \$0.47 per bbl for the fourth quarter of 2020 and decreased 3% from \$0.33 per bbl for the third quarter of 2021. Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

## MIDSTREAM AND REFINING

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Product sales					
Midstream activities	\$ 17	\$ 21	\$ 21	\$ 78	\$ 83
NWRP, refined product sales and other	200	179	99	681	202
Segmented revenue	217	200	120	759	285
Less:					
NWRP, refining toll	37	46	72	213	166
Midstream activities	5	4	3	21	18
Production expense	42	50	75	234	184
NWRP, transportation and feedstock costs	165	146	83	550	181
Depreciation	4	4	4	15	15
Income from NWRP	—	—	—	(400)	—
Segmented earnings (loss)	\$ 6	\$ —	\$ (42)	\$ 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.

NWRP operates a 50,000 bbl/d bitumen upgrader and refinery that processes approximately 12,500 bbl/d (25% toll payer) of bitumen feedstock for the Company and 37,500 bbl/d (75% toll payer) of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period. Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment. For the fourth quarter of 2021, production of ultra-low sulphur diesel and other refined products averaged 71,433 BOE/d (17,858 BOE/d to the Company), (three months ended December 31, 2020 – 65,670 BOE/d; 16,417 BOE/d to the Company), reflecting the 25% toll payer commitment.

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 the second quarter of 2021.

As at December 31, 2021, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was \$562 million (December 31, 2020 – \$153 million). For the three months ended December 31, 2021, unrecognized share of the equity loss was \$12 million (year ended December 31, 2021 – unrecognized equity loss of \$9 million and partnership distributions of \$400 million; three months ended December 31, 2020 – unrecognized equity income of \$6 million; year ended December 31, 2020 – unrecognized equity loss of \$94 million).

## ADMINISTRATION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Expense (\$ millions)	\$ 97	\$ 87	\$ 107	\$ 366	\$ 391
\$/BOE <sup>(1)</sup>	\$ 0.81	\$ 0.77	\$ 0.96	\$ 0.81	\$ 0.92
Sales volumes (BOE/d) <sup>(2)</sup>	1,310,878	1,236,813	1,213,746	1,233,457	1,166,862

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

(2) Total Company sales volumes.

Administration expense for the year ended December 31, 2021 of \$0.81 per BOE decreased 12% from \$0.92 per BOE for the year ended December 31, 2020. Administration expense for the fourth quarter of 2021 of \$0.81 per BOE decreased 16% from \$0.96 per BOE for the fourth quarter of 2020 and increased 5% from \$0.77 per BOE for the third quarter of 2021. The decrease in administration expense per BOE for the three months and year ended December 31, 2021 from the comparable periods in 2020 was primarily due to higher sales volumes and higher overhead recoveries. The increase in administration expense per BOE for the fourth quarter of 2021 from the third quarter of 2021 was primarily due to higher personnel costs, partially offset by the impact of higher overhead recoveries.

## SHARE-BASED COMPENSATION

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Expense (recovery)	\$ 191	\$ 57	\$ 123	\$ 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 a \$514 million share-based compensation expense for the year ended December 31, 2021, primarily as a result of the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period, and changes in the Company's share price. An expense of \$79 million related to PSUs granted to certain executive employees was included in the share-based compensation expense for the year ended December 31, 2021 (December 31, 2020 – \$21 million expense).

## INTEREST AND OTHER FINANCING EXPENSE

(\$ millions, except effective interest rate)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Interest and other financing expense	\$ 171	\$ 178	\$ 177	\$ 711	\$ 756
Interest income and other <sup>(1)</sup>	2	3	19	32	72
Capitalized interest <sup>(1)</sup>	—	—	3	—	24
Interest on long-term debt and lease liabilities <sup>(1)</sup>	\$ 173	\$ 181	\$ 199	\$ 743	\$ 852
Average current and long-term debt <sup>(2)</sup>	\$ 16,084	\$ 18,165	\$ 22,439	\$ 18,935	\$ 22,446
Average lease liabilities <sup>(2)</sup>	1,578	1,599	1,698	1,619	1,708
Average long-term debt and lease liabilities <sup>(2)</sup>	\$ 17,662	\$ 19,764	\$ 24,137	\$ 20,554	\$ 24,154
Average effective interest rate <sup>(3) (4)</sup>	3.9%	3.6%	3.3%	3.5%	3.5%
Interest and other financing expense per \$/BOE <sup>(5)</sup>	\$ 1.42	\$ 1.56	\$ 1.59	\$ 1.58	\$ 1.77
Sales volumes (BOE/d) <sup>(6)</sup>	1,310,878	1,236,813	1,213,746	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 their most directly comparable financial measure presented in the 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 the year ended December 31, 2021 decreased 11% to \$1.58 per BOE from \$1.77 per BOE for the year ended December 31, 2020. Interest and other financing expense per BOE for the fourth quarter of 2021 decreased 11% to \$1.42 per BOE from \$1.59 per BOE for the fourth quarter of 2020 and decreased 9% from \$1.56 per BOE for the third quarter of 2021. The decrease in interest expense and other financing expense per BOE for the three months and year ended December 31, 2021 from the comparable periods was primarily due to higher sales volumes and lower average debt levels in 2021, partially offset by lower interest income.

The Company's average effective interest rate for the fourth quarter of 2021 increased from the third quarter of 2021 primarily due to the repayment of outstanding bank credit facilities and less US commercial paper outstanding.

## 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)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Natural gas financial instruments	\$ 6	\$ 14	\$ (2)	\$ 17	\$ 16
Crude oil and NGLs financial instruments	(1)	—	—	(1)	—
Foreign currency contracts	(11)	(18)	25	1	16
Net realized (gain) loss	(6)	(4)	23	17	32
Natural gas financial instruments	(10)	(18)	(27)	11	(36)
Crude oil and NGLs financial instruments	2	—	—	2	—
Foreign currency contracts	16	(1)	6	6	(3)
Net unrealized loss (gain)	8	(19)	(21)	19	(39)
Net loss (gain)	\$ 2	\$ (23)	\$ 2	\$ 36	\$ (7)

During the year ended December 31, 2021, net realized risk management losses were related to the settlement of natural gas financial instruments, crude oil and NGLs financial instruments and foreign currency contracts. The Company recorded a net unrealized loss of \$19 million (\$16 million after-tax of \$3 million) on its risk management activities for the year ended December 31, 2021, including an unrealized loss of \$8 million (\$10 million after-tax of \$2 million) for the fourth quarter of 2021 (September 30, 2021 – unrealized gain of \$19 million, \$15 million after-tax of \$4 million; December 31, 2020 – unrealized gain of \$21 million, \$16 million after-tax of \$5 million).

Further details related to outstanding derivative financial instruments at December 31, 2021 are disclosed in note 15 to the financial statements.

## FOREIGN EXCHANGE

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Net realized (gain) loss	\$ (27)	\$ 84	\$ 21	\$ 78	\$ (159)
Net unrealized (gain) loss	(79)	197	(534)	(205)	(116)
Net (gain) loss <sup>(1)</sup>	\$ (106)	\$ 281	\$ (513)	\$ (127)	\$ (275)

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

The net realized foreign exchange loss for the year ended December 31, 2021 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US\$500 million of 3.45% debt securities. The net unrealized foreign exchange gain for the year ended December 31, 2021 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt and the reversal of the net unrealized foreign exchange loss on the repayment of US\$500 million of 3.45% debt securities. The US/Canadian dollar exchange rate at December 31, 2021 was US\$0.7901 (September 30, 2021 – US\$0.7843, December 31, 2020 – US\$0.7840).

## INCOME TAXES

(\$ millions, except effective tax rates)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
North America <sup>(1)</sup>	\$ 691	\$ 541	\$ 42	\$ 1,841	\$ (245)
North Sea	(3)	4	—	7	(4)
Offshore Africa	3	7	5	21	17
PRT <sup>(2)</sup> – North Sea	(12)	(5)	(14)	(34)	(31)
Other taxes	4	4	2	13	6
Current income tax	683	551	35	1,848	(257)
Deferred income tax	193	56	(25)	399	(181)
Income tax	\$ 876	\$ 607	\$ 10	\$ 2,247	\$ (438)
Earnings (loss) before taxes	\$ 3,410	\$ 2,809	\$ 759	\$ 9,911	\$ (873)
Effective tax rate on net earnings (loss) <sup>(3)</sup>	26%	22%	1%	23%	50%
Income tax	\$ 876	\$ 607	\$ 10	\$ 2,247	\$ (438)
Tax effect on non-operating items <sup>(4)</sup>	—	(6)	34	5	29
Current PRT - North Sea	12	5	14	34	31
Other taxes	(4)	(4)	(2)	(13)	(6)
Effective tax on adjusted net earnings (loss)	\$ 884	\$ 602	\$ 56	\$ 2,273	\$ (384)
Adjusted net earnings (loss) from operations <sup>(5)</sup>	\$ 2,626	\$ 2,095	\$ 176	\$ 7,420	\$ (756)
Effective tax on adjusted net earnings (loss)	884	602	56	2,273	(384)
Adjusted net earnings (loss) from operations, before taxes	\$ 3,510	\$ 2,697	\$ 232	\$ 9,693	\$ (1,140)
Effective tax rate on adjusted net earnings (loss) from operations <sup>(6)(7)</sup>	25%	22%	24%	23%	34%

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

(2) Petroleum Revenue Tax.

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

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

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

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

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

The effective tax rate on net earnings (loss) and adjusted net earnings (loss) from operations for the three months and year ended December 31, 2021 and the comparable periods 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 for the three months and year ended December 31, 2021 and the prior periods included the impact of carrybacks of abandonment expenditures related to decommissioning activities at the Company's platforms in the North Sea.

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

## NET CAPITAL EXPENDITURES <sup>(1) (2)</sup>

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
<b>Exploration and Evaluation</b>					
Net property dispositions	\$ (6)	\$ (1)	\$ (1)	\$ (11)	\$ (31)
Net expenditures	2	5	9	12	36
Total Exploration and Evaluation	(4)	4	8	1	5
<b>Property, Plant and Equipment</b>					
Net property acquisitions <sup>(3) (4)</sup>	973	131	522	1,112	536
Well drilling, completion and equipping	196	232	115	918	429
Production and related facilities	180	244	131	802	580
Other	23	12	20	64	60
Total Property, Plant and Equipment	1,372	619	788	2,896	1,605
Total Exploration and Production	1,368	623	796	2,897	1,610
<b>Oil Sands Mining and Upgrading</b>					
Project costs	65	69	86	236	258
Sustaining capital	270	233	212	1,035	839
Turnaround costs	23	19	22	145	196
Other <sup>(5)</sup>	1	3	4	331	30
Total Oil Sands Mining and Upgrading	359	324	324	1,747	1,323
<b>Midstream and Refining</b>	3	3	1	9	5
<b>Head office</b>	7	7	3	23	19
<b>Abandonments expenditures, net <sup>(2)</sup></b>	67	54	52	232	249
Net capital expenditures	\$ 1,804	\$ 1,011	\$ 1,176	\$ 4,908	\$ 3,206
<b>By segment</b>					
North America	\$ 1,301	\$ 564	\$ 729	\$ 2,662	\$ 1,389
North Sea	48	49	34	173	122
Offshore Africa	19	10	33	62	99
Oil Sands Mining and Upgrading	359	324	324	1,747	1,323
Midstream and Refining	3	3	1	9	5
Head office	7	7	3	23	19
Abandonments expenditures, net <sup>(2)</sup>	67	54	52	232	249
Net capital expenditures	\$ 1,804	\$ 1,011	\$ 1,176	\$ 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 the fourth quarter of 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 Energy Ltd. ("Painted Pony") in the fourth quarter of 2020.

(5) Includes the acquisition of a 5% net carried interest on an existing oil sands lease in the second quarter of 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 the year ended December 31, 2021 were \$4,908 million compared with \$3,206 million for the year ended December 31, 2020. Net capital expenditures for the fourth quarter of 2021 were \$1,804 million compared with \$1,176 million for the fourth quarter of 2020 and \$1,011 million for the third quarter of 2021.

On December 17, 2021, the Company completed the acquisition of all the issued and outstanding common shares of Storm for total cash consideration of approximately \$771 million. At closing, the acquisition also included the assumption of long-term debt of approximately \$183 million. Storm is involved in the exploration for and development of natural gas and natural gas liquids in the Montney region of British Columbia.

During the year ended December 31, 2021, the Company also completed a number of other opportunistic acquisitions. Two acquisitions consisted of natural gas assets located in the Montney region of British Columbia. A third acquisition consisted of a net carried interest on an existing oil sands lease held by the Company, from which all Horizon production volumes are derived. Total cash consideration paid for these acquisitions was approximately \$450 million.

## 2022 Capital Budget

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

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

## Drilling Activity <sup>(1)</sup>

	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
(number of net wells)					
Net successful natural gas wells	9	9	9	49	30
Net successful crude oil wells <sup>(2)</sup>	22	56	5	149	42
Dry wells	—	1	—	1	—
Stratigraphic test / service wells	57	7	—	393	372
Total	88	73	14	592	444
Success rate (excluding stratigraphic test / service wells)	100%	98%	100%	99%	100%

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

(2) Includes bitumen wells.

## North America

During the fourth quarter of 2021, the Company drilled 9 net natural gas wells, 11 net primary heavy crude oil wells, 1 net bitumen (thermal oil) well and 9 net light crude oil wells.

## North Sea

During the fourth quarter of 2021, the Company drilled 1.0 net light crude oil well in the North Sea.

## LIQUIDITY AND CAPITAL RESOURCES

(\$ millions, except ratios)	<b>Dec 31 2021</b>	Sep 30 2021	Dec 31 2020
Adjusted working capital <sup>(1)</sup>	<b>\$ (480)</b>	\$ 423	\$ 626
Long-term debt, net <sup>(2)</sup>	<b>\$ 13,950</b>	\$ 15,880	\$ 21,269
Shareholders' equity	<b>\$ 36,945</b>	\$ 35,526	\$ 32,380
Debt to book capitalization <sup>(2)</sup>	<b>27.4%</b>	30.9%	39.6%
After-tax return on average capital employed <sup>(3)</sup>	<b>15.6%</b>	12.1%	0.2%

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

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

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

As at December 31, 2021, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Business Environment" section of this MD&A and in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2020. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and market conditions. The Company continues to believe its internally generated cash flows from operating activities supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long-term and support its growth strategy.

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

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Reviewing the Company's borrowing capacity:
  - During the fourth quarter of 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 the first quarter of 2021, the \$1,000 million non-revolving term credit facility, originally due February 2022, was extended to February 2023. During the fourth quarter of 2021, the facility was fully repaid. The facility was amended to allow for a re-draw of the full \$1,000 million until March 31, 2022.
  - During the third quarter of 2021, the Company repaid \$500 million of the \$2,650 million non-revolving term credit facility, reducing the outstanding balance to \$2,150 million. During the fourth quarter of 2021, the Company repaid an additional \$1,000 million on the facility, reducing the outstanding balance to \$1,150 million.

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

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

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

Net long-term debt was \$13,950 million at December 31, 2021, resulting in a debt to book capitalization ratio of 27.4% (December 31, 2020 – 39.6%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities are greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at December 31, 2021 are discussed in note 8 to the financial statements.

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

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2021 are discussed in note 15 to the financial statements.

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

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

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

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

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

## Share Capital

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

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

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

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

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

## COMMITMENTS AND CONTINGENCIES

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

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

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

(2) The acquisition of Storm in the fourth quarter of 2021 included approximately \$298 million of product transportation and processing commitments.

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

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

## LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

## REGULATORY DEVELOPMENTS

On May 27, 2021, the Canadian Securities Administrators ("CSA") announced the adoption of NI 52-112 and related amendments. This National Instrument replaces the previous CSA staff notice on Non-GAAP Measures. NI 52-112 governs how entities present non-GAAP and other financial measures and ratios. The requirements apply to the Company's MD&A and certain other disclosure documents for the three months and year ended December 31, 2021.

## 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. For the three months and year ended December 31, 2021, COVID-19 continued to have an impact on the global economy, including the oil and gas industry. Business conditions in the fourth quarter of 2021 continued to reflect the market uncertainty associated with COVID-19. The Company has taken into account the impacts of COVID-19 and the unique circumstances it has created in making estimates, assumptions, and judgements in the preparation of the unaudited interim consolidated financial statements, and continues to monitor the developments in the business environment and commodity market. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the Company's annual MD&A and audited consolidated financial statements for the year ended December 31, 2020.

## CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the year ended December 31, 2021 that have materially affected, or are reasonably likely to materially affect the Company's ICFR. Due to inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

## 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 financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this MD&A, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below.

### Adjusted Net Earnings (Loss) from Operations

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

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Net earnings (loss)	\$ 2,534	\$ 2,202	\$ 749	\$ 7,664	\$ (435)
Share-based compensation, net of tax <sup>(1)</sup>	183	54	117	495	(86)
Unrealized risk management loss (gain), net of tax <sup>(2)</sup>	10	(15)	(16)	16	(31)
Unrealized foreign exchange (gain) loss, net of tax <sup>(3)</sup>	(79)	197	(534)	(205)	(116)
Realized foreign exchange loss (gain), net of tax <sup>(4)</sup>	—	118	—	118	(166)
Gain on acquisitions, net of tax <sup>(5)</sup>	—	(478)	(217)	(478)	(217)
(Gain) loss from investments, net of tax <sup>(6)</sup>	(3)	35	(33)	(132)	185
Other, net of tax <sup>(7)</sup>	(19)	(18)	110	(58)	110
Non-operating items (after-tax)	92	(107)	(573)	(244)	(321)
Adjusted net earnings (loss) from operations	\$ 2,626	\$ 2,095	\$ 176	\$ 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 the three months ended December 31, 2021 was an expense of \$191 million (three months ended September 30, 2021 – \$57 million expense, December 31, 2020 – \$123 million expense; year ended December 31, 2021 – \$514 million expense, December 31, 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 financial statements due to changes in prices of the underlying items hedged, primarily natural gas and foreign exchange. Pre-tax unrealized risk management loss for the three months ended December 31, 2021 was \$8 million (three months ended September 30, 2021 – \$19 million gain, December 31, 2020 – \$21 million gain; year ended December 31, 2021 – \$19 million loss, December 31, 2020 – \$39 million gain).

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

(4) During the third quarter of 2021, the Company repaid US\$500 million of 3.45% debt securities, originally due November 2021, resulting in a pre- and after-tax foreign exchange loss of \$118 million. During the first quarter of 2020, the Company settled the US\$500 million cross currency swaps designated as cash flow hedges of the US\$500 million 3.45% US dollar debt securities due November 2021. The Company realized cash proceeds of \$166 million on settlement. There was net zero tax impact on the settlement.

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

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

(7) For the year ended December 31, 2021, the Company recognized the impact of government grant income under the provincial well-site rehabilitation programs of \$75 million (\$58 million after-tax) including \$25 million (\$19 million after-tax) for the fourth quarter of 2021 (September 30, 2021 – \$23 million, \$18 million after-tax). During the three months and year ended December 31, 2020, the Company recognized a provision in transportation, blending and feedstock expense of \$143 million (\$110 million after-tax) relating to the Keystone XL pipeline project.

## 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)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Cash flows from operating activities	\$ 4,712	\$ 4,290	\$ 1,270	\$ 14,478	\$ 4,714
Net change in non-cash working capital	(420)	(691)	394	(964)	166
Abandonment expenditures, net <sup>(1)</sup>	67	54	52	232	249
Movements in other long-term assets <sup>(2)</sup>	(21)	(19)	(8)	(13)	71
<b>Adjusted funds flow</b>	<b>\$ 4,338</b>	<b>\$ 3,634</b>	<b>\$ 1,708</b>	<b>\$ 13,733</b>	<b>\$ 5,200</b>

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

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

## Adjusted Net Earnings (Loss) from Operations and Adjusted Funds Flow, Per Share (Basic and Diluted)

Adjusted net earnings (loss) from operations and adjusted funds flow, per share (basic and diluted), are non-GAAP ratios that represent those non-GAAP measures divided by the weighted average number of basic and diluted common shares outstanding for the period, respectively, as presented in note 14 to the financial statements.

## Abandonment Expenditures, net

Abandonment expenditures, net, is a non-GAAP financial measure that represents the abandonment expenditures to settle asset retirement obligations as reflected in the Company's annual capital budget. Abandonment expenditures, net is calculated as abandonment expenditures, as presented in the Company's 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)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Abandonment expenditures	\$ 92	\$ 77	\$ 52	\$ 307	\$ 249
Government grants for abandonment expenditures	(25)	(23)	—	(75)	—
<b>Abandonment expenditures, net</b>	<b>\$ 67</b>	<b>\$ 54</b>	<b>\$ 52</b>	<b>\$ 232</b>	<b>\$ 249</b>

## 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" section 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 17 to the 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)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
<b>Crude oil and NGLs (bbl/d)</b>					
North America	490,448	448,948	476,240	471,331	465,073
North Sea	21,360	16,028	20,100	18,942	22,852
Offshore Africa	5,624	19,402	19,961	13,452	17,017
Sales volumes	517,432	484,378	516,301	503,725	504,942
Crude oil and NGLs sales <sup>(1)</sup>	\$ 4,667	\$ 3,810	\$ 2,568	\$ 15,505	\$ 8,215
Less: Blending costs <sup>(2)</sup>	1,202	777	641	3,792	2,321
Realized crude oil and NGLs sales	\$ 3,465	\$ 3,033	\$ 1,927	\$ 11,713	\$ 5,894
Realized price (\$/bbl)	\$ 72.81	\$ 68.06	\$ 40.56	\$ 63.71	\$ 31.90

(1) Crude oil and NGLs sales in note 17 to the financial statements.

(2) 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)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
<b>Barrels of oil equivalent (BOE/d)</b>					
North America	797,185	731,962	746,684	751,330	706,799
North Sea	21,940	16,427	20,817	19,512	24,805
Offshore Africa	7,781	20,652	22,807	15,385	19,517
Sales volumes	826,906	769,041	790,308	786,227	751,121
Barrels of oil equivalent sales <sup>(1)</sup>	\$ 5,581	\$ 4,460	\$ 3,013	\$ 18,025	\$ 9,511
Less: Blending costs <sup>(2)</sup>	1,202	777	641	3,792	2,321
Less: Sulphur (income) expense	(12)	(3)	—	(21)	4
Realized barrels of oil equivalent sales	\$ 4,391	\$ 3,686	\$ 2,372	\$ 14,254	\$ 7,186
Realized price (\$/BOE)	\$ 57.72	\$ 52.09	\$ 32.61	\$ 49.67	\$ 26.15

(1) Barrels of oil equivalent sales includes crude oil and NGLs sales and natural gas sales in note 17 to the financial statements.

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

## Transportation – Exploration and Production

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

(\$ millions, except \$ per unit amounts)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Transportation, blending and feedstock <sup>(1)</sup>	\$ 1,461	\$ 1,025	\$ 1,028	\$ 4,780	\$ 3,409
Less: Blending costs	1,202	777	641	3,792	2,321
Less: Other <sup>(2)</sup>	—	—	143	—	143
Transportation	\$ 259	\$ 248	\$ 244	\$ 988	\$ 945
Transportation (\$/BOE)	\$ 3.40	\$ 3.50	\$ 3.37	\$ 3.44	\$ 3.44
Amounts attributed to crude oil and NGLs	\$ 187	\$ 178	\$ 181	\$ 710	\$ 711
Transportation (\$/bbl)	\$ 3.93	\$ 4.00	\$ 3.81	\$ 3.86	\$ 3.85
Amounts attributed to natural gas	\$ 72	\$ 70	\$ 63	\$ 278	\$ 234
Transportation (\$/Mcf)	\$ 0.42	\$ 0.44	\$ 0.42	\$ 0.45	\$ 0.43

(1) Transportation, blending and feedstock in note 17 to the financial statements.

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

## North America – Realized Product Prices & 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)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Crude oil and NGLs sales <sup>(1)</sup>	\$ 4,431	\$ 3,506	\$ 2,374	\$ 14,478	\$ 7,480
Less: Blending costs <sup>(2)</sup>	1,202	777	641	3,792	2,321
Realized crude oil and NGLs sales	\$ 3,229	\$ 2,729	\$ 1,733	\$ 10,686	\$ 5,159
Realized crude oil and NGLs prices (\$/bbl)	\$ 71.57	\$ 66.03	\$ 39.54	\$ 62.10	\$ 30.31
Crude oil and NGLs royalties <sup>(3)</sup>	\$ 506	\$ 414	\$ 155	\$ 1,558	\$ 464
Crude oil and NGLs royalty rates	16%	15%	9%	15%	9%

(1) Crude oil and NGLs sales in note 17 to the 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 17 to the financial statements.

## Realized Product Prices and Transportation – Oil Sands Mining and Upgrading

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

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

Reconciliations for Oil Sands Mining and Upgrading realized SCO sales and transportation and the calculations for realized SCO sales price and transportation are presented below.

(\$ millions, except for bbl/d and \$/bbl)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
SCO sales volumes (bbl/d)	<b>483,972</b>	467,772	423,438	<b>447,230</b>	415,741
Crude oil and NGLs sales <sup>(1)</sup>	\$ <b>4,408</b>	\$ 3,848	\$ 2,078	\$ <b>14,033</b>	\$ 7,389
Less: blending and feedstock costs	<b>468</b>	339	187	<b>1,309</b>	695
Realized SCO sales	\$ <b>3,940</b>	\$ 3,509	\$ 1,891	\$ <b>12,724</b>	\$ 6,694
Realized SCO sales price (\$/bbl)	\$ <b>88.48</b>	\$ 81.54	\$ 48.56	\$ <b>77.95</b>	\$ 43.98
Transportation, blending and feedstock <sup>(2)</sup>	\$ <b>527</b>	\$ 387	\$ 240	\$ <b>1,505</b>	\$ 881
Less: blending and feedstock costs	<b>468</b>	339	187	<b>1,309</b>	695
Transportation	\$ <b>59</b>	\$ 48	\$ 53	\$ <b>196</b>	\$ 186
Transportation (\$/bbl)	\$ <b>1.33</b>	\$ 1.14	\$ 1.36	\$ <b>1.21</b>	\$ 1.23

(1) Crude oil and NGLs sales in note 17 to the financial statements.

(2) Transportation, blending and feedstock in note 17 to the 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 consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, proceeds from investment, the repayment of NWRP subordinated debt advances, abandonment expenditures including the impact of government grant income under the provincial well-site rehabilitation programs, and the settlement of long-term debt assumed in acquisitions. The Company considers net capital expenditures a key measure in evaluating its performance, as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. A reconciliation of net capital expenditures is presented below.

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2021	Sep 30 2021	Dec 31 2020	Dec 31 2021	Dec 31 2020
Cash flows used in investing activities	\$ <b>1,615</b>	\$ 721	\$ 624	\$ <b>3,703</b>	\$ 2,819
Net change in non-cash working capital	<b>(61)</b>	108	(21)	<b>107</b>	(383)
Proceeds from investment	—	128	—	<b>128</b>	—
Repayment of NWRP subordinated debt advances	—	—	124	<b>555</b>	124
Capital expenditures	<b>1,554</b>	957	727	<b>4,493</b>	2,560
Abandonment expenditures, net <sup>(1)</sup>	<b>67</b>	54	52	<b>232</b>	249
Settlement of long-term debt acquired <sup>(2)</sup>	<b>183</b>	—	397	<b>183</b>	397
Net capital expenditures	\$ <b>1,804</b>	\$ 1,011	\$ 1,176	\$ <b>4,908</b>	\$ 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 the fourth quarter of 2021 and Painted Pony in the fourth quarter of 2020.

## Liquidity

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

(\$ millions)	Dec 31 2021	Sep 30 2021	Dec 31 2020
Undrawn bank credit facilities	\$ 6,098	\$ 4,959	\$ 4,958
Cash and cash equivalents	744	894	184
Investments	309	306	305
Liquidity	\$ 7,151	\$ 6,159	\$ 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 13 to the 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 13 to the 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)	Dec 31 2021	Sep 30 2021	Dec 31 2020
Interest adjusted after-tax return:			
Net earnings (loss), 12 months trailing	\$ 7,664	\$ 5,879	\$ (435)
Interest and other financing expense, net of tax, 12 months trailing <sup>(1)</sup>	547	552	571
Interest adjusted after-tax return	\$ 8,211	\$ 6,431	\$ 136
12 months average current portion long-term debt <sup>(2)</sup>	\$ 1,483	\$ 1,449	\$ 1,842
12 months average long-term debt <sup>(2)</sup>	16,769	18,240	20,162
12 months average common shareholders' equity <sup>(2)</sup>	34,458	33,502	33,026
12 months average capital employed	\$ 52,710	\$ 53,191	\$ 55,030
After-tax return on average capital employed	15.6%	12.1%	0.2%

(1) The blended tax rate on interest was 23% for December 31, 2021, 23% for September 30, 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.