Canadian Natural

Canadian Natural Resources Limited

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS ENDED MARCH 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"), Primrose thermal oil projects, the Pelican Lake water and polymer flood projects, the Kirby Thermal Oil Sands Project, the Jackfish Thermal Oil Sands Project, 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 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; the continued availability of the Canada Emergency Wage Subsidy ("CEWS") or other subsidies; 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 Financial Measures

This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings (loss) from operations, adjusted funds flow and net capital expenditures. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP financial measures. The non-GAAP financial measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP financial measures to evaluate its performance. The non-GAAP financial measures should not be considered an alternative to or more meaningful than net earnings (loss), cash flows from operating activities, and cash flows used in investing activities as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP financial measure adjusted net earnings (loss) from operations is reconciled to net earnings (loss), as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. Additionally, the non-GAAP financial measure adjusted funds flow is reconciled to cash flows from operating activities, as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The non-GAAP financial measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the "Net Capital Expenditures" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

Special Note Regarding Currency, Financial Information and Production

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 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 unaudited interim consolidated financial statements for the three months ended March 31, 2021 and this MD&A have been prepared in accordance with 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 ended March 31, 2021 in relation to the first quarter of 2020 and the fourth quarter of 2020. 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, and on EDGAR at www.sec.gov. Information on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated May 5, 2021.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Mar 31 2021	Dec 31 2020	Mar 31 2020
Product sales [(1)]	**$ 7,019**	$ 5,219	$ 4,652
Crude oil and NGLs	**$ 6,288**	$ 4,592	$ 4,323
Natural gas	**$ 555**	$ 496	$ 337
Net earnings (loss)	**$ 1,377**	$ 749	$ (1,282)
Per common share – basic	**$ 1.16**	$ 0.63	$ (1.08)
– diluted	**$ 1.16**	$ 0.63	$ (1.08)
Adjusted net earnings (loss) from operations [(2)]	**$ 1,219**	$ 176	$ (295)
Per common share – basic	**$ 1.03**	$ 0.15	$ (0.25)
– diluted	**$ 1.03**	$ 0.15	$ (0.25)
Cash flows from operating activities	**$ 2,536**	$ 1,270	$ 1,725
Adjusted funds flow [(3)]	**$ 2,712**	$ 1,708	$ 1,337
Per common share – basic	**$ 2.29**	$ 1.45	$ 1.13
– diluted	**$ 2.28**	$ 1.44	$ 1.13
Cash flows used in investing activities	**$ 648**	$ 624	$ 859
Net capital expenditures [(4)]	**$ 808**	$ 1,176	$ 838

(1) Further details related to product sales are disclosed in note 17 to the Company’s unaudited interim consolidated financial statements.

(2) Adjusted net earnings (loss) from operations is a non-GAAP financial measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for the after-tax effects of certain items of a non-operational nature. 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. The reconciliation "Adjusted Net Earnings (Loss) from Operations, as Reconciled to Net Earnings (Loss)" is presented in this MD&A. Adjusted net earnings (loss) from operations may not be comparable to similar measures presented by other companies.

(3) 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, including the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to North West Redwater Partnership ("NWRP"), and prepaid cost of service tolls. 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. The reconciliation "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" is presented in this MD&A. Adjusted funds flow may not be comparable to similar measures presented by other companies.

(4) 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, 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. The reconciliation "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" is presented in the "Net Capital Expenditures" section of this MD&A. Net capital expenditures may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings (Loss) from Operations, as Reconciled to Net Earnings (Loss)

($ millions)	Three Months Ended **Mar 31 2021**	Dec 31 2020	Mar 31 2020
Net earnings (loss)	**$ 1,377**	$ 749	$ (1,282)
Share-based compensation, net of tax (1)	**126**	117	(221)
Unrealized risk management loss (gain), net of tax (2)	**15**	(16)	(15)
Unrealized foreign exchange (gain) loss, net of tax (3)	**(172)**	(534)	1,121
Realized foreign exchange gain on settlement of cross currency swaps, net of tax (4)	**—**	—	(166)
Gain on acquisition, net of tax (5)	**—**	(217)	—
(Gain) loss from investments, net of tax (6)	**(117)**	(33)	268
Other, net of tax (7)	**(10)**	110	—
Adjusted net earnings (loss) from operations	**$ 1,219**	$ 176	$ (295)

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("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) or are charged to (recovered from) the Oil Sands Mining and Upgrading segment.

(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.

(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).

(4) 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.

(5) 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 Energy Ltd. ("Painted Pony").

(6) The Company's investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("Inter Pipeline") have been accounted for at fair value through profit and loss and are remeasured each period with changes in fair value recognized in net earnings (loss).

(7) During the first quarter of 2021, other reflects the after-tax impact of government grant income under the provincial well-site rehabilitation programs and during the fourth quarter of 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, as Reconciled to Cash Flows from Operating Activities

($ millions)	Three Months Ended **Mar 31 2021**	Dec 31 2020	Mar 31 2020
Cash flows from operating activities	**$ 2,536**	$ 1,270	$ 1,725
Net change in non-cash working capital	**10**	394	(595)
Abandonment expenditures (1)	**67**	52	89
Other (2)	**99**	(8)	118
Adjusted funds flow	**$ 2,712**	$ 1,708	$ 1,337

(1) The Company includes abandonment expenditures in "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" in the "Net Capital Expenditures" section of this MD&A and excludes the impact of government grant income under the provincial well-site rehabilitation programs.

(2) 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.

SUMMARY OF FINANCIAL HIGHLIGHTS

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

Net earnings for the first quarter of 2021 were $1,377 million compared with a net loss of $1,282 million for the first quarter of 2020 and net earnings of $749 million for the fourth quarter of 2020. Net earnings for the first quarter of 2021 included net after-tax income of $158 million compared with net after-tax expenses of $987 million for the first quarter of 2020 and net after-tax income of $573 million for the fourth quarter of 2020 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the foreign exchange gain on the settlement of the cross currency swaps, the gain on acquisition, 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 first quarter of 2021 were $1,219 million compared with an adjusted net loss from operations of $295 million for the first quarter of 2020 and adjusted net earnings from operations of $176 million for the fourth quarter of 2020.

The increase in net earnings and adjusted net earnings from operations for the first quarter of 2021 compared with the net earnings (loss) and adjusted net earnings (loss) from operations for the comparable periods primarily reflected:

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

The impacts of share-based compensation, risk management activities, fluctuations in foreign exchange rates, and the gain on acquisition 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 first quarter of 2021 were $2,536 million compared with $1,725 million for the first quarter of 2020 and $1,270 million for the fourth quarter of 2020. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors previously noted relating to the fluctuations in adjusted net earnings (loss) from operations, as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the first quarter of 2021 was $2,712 million compared with $1,337 million for the first quarter of 2020 and $1,708 million for the fourth quarter of 2020. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above relating 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

Total production of crude oil and NGLs before royalties for the first quarter of 2021 increased 4% to 979,352 bbl/d from 938,676 bbl/d for the first quarter of 2020 and increased 6% from 927,190 bbl/d for the fourth quarter of 2020. Total natural gas production before royalties for the first quarter of 2021 increased 11% to 1,598 MMcf/d from 1,440 MMcf/d for the first quarter of 2020 and was comparable with 1,644 MMcf/d for the fourth quarter of 2020. Total production before royalties for the first quarter of 2021 increased 6% to 1,245,703 BOE/d from 1,178,752 BOE/d for the first quarter of 2020 and increased 4% from 1,201,198 BOE/d for the fourth quarter of 2020. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

Product Prices

The Company's realized pricing primarily reflects prevailing benchmark pricing. In the Company's Exploration and Production segments, the first quarter of 2021 crude oil and NGLs sales price averaged $52.68 per bbl, an increase of 103% compared with $25.90 per bbl for the first quarter of 2020, and an increase of 30% from $40.56 per bbl for the fourth quarter of 2020. The natural gas price increased 54% to average $3.42 per Mcf for the first quarter of 2021 from $2.22 per Mcf for the first quarter of 2020, and increased 16% from $2.94 per Mcf for the fourth quarter of 2020. In the Oil Sands Mining and Upgrading segment, the Company's SCO sales price increased 27% to average $64.60 per bbl for the first quarter of 2021 from $50.88 per bbl from the first quarter of 2020, and increased 33% from $48.56 per bbl for the fourth quarter of 2020. Crude oil and NGLs and natural gas prices are discussed in detail in the "Business Environment", "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, first quarter of 2021 crude oil and NGLs production expense averaged $14.56 per bbl, an increase of 6% from $13.71 for the first quarter of 2020, and an increase of 17% from $12.47 per bbl for the fourth quarter of 2020. Natural gas production expense averaged $1.27 per Mcf for the first quarter of 2021, a decrease of 3% from $1.31 per Mcf for the first quarter of 2020 and an increase of 15% from $1.10 per Mcf for the fourth quarter of 2020. In the Oil Sands Mining and Upgrading segment, production costs averaged $19.82 per bbl for the first quarter of 2021, a decrease of 5% from $20.76 per bbl for the first quarter of 2020, and a decrease of 2% from $20.20 per bbl for the fourth quarter of 2020. 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)		**Mar 31 2021**		Dec 31 2020		Sep 30 2020		Jun 30 2020
Product sales [1]	**$**	**7,019**	$	5,219	$	4,676	$	2,944
Crude oil and NGLs	**$**	**6,288**	$	4,592	$	4,202	$	2,462
Natural gas	**$**	**555**	$	496	$	338	$	307
Net earnings (loss)	**$**	**1,377**	$	749	$	408	$	(310)
Net earnings (loss) per common share								
– basic	**$**	**1.16**	$	0.63	$	0.35	$	(0.26)
– diluted	**$**	**1.16**	$	0.63	$	0.35	$	(0.26)

($ millions, except per common share amounts)		Mar 31 2020		Dec 31 2019		Sep 30 2019		Jun 30 2019
Product sales [1]	$	4,652	$	6,335	$	6,587	$	5,931
Crude oil and NGLs	$	4,323	$	5,947	$	6,324	$	5,597
Natural gas	$	337	$	382	$	257	$	324
Net earnings (loss)	$	(1,282)	$	597	$	1,027	$	2,831
Net earnings (loss) per common share								
– basic	$	(1.08)	$	0.50	$	0.87	$	2.37
– diluted	$	(1.08)	$	0.50	$	0.87	$	2.36

(1) Further details related to product sales for the three months ended March 31, 2021 and 2020 are disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

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 including the impact of a shortage of takeaway capacity out of the Western Canadian Sedimentary Basin (the "Basin"); 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 due to the cyclic nature of the Company's Primrose thermal oil projects, production from the Kirby Thermal Oil Sands Project, the results from the Pelican Lake water and polymer flood projects, fluctuations in the Company's drilling program in North America and the International segments, the impact and timing of acquisitions, including the acquisition of assets from Devon Canada Corporation ("Devon") in the second quarter of 2019, as well as 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 higher return crude oil projects, natural decline rates, shut-in production due to low commodity prices and the impact and timing of acquisitions, including the acquisition of Painted Pony in the fourth quarter of 2020.
- **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 seasonal costs, 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 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 acquisition and gains/losses on investments** – Fluctuations due to the recognition of a gain on the acquisition of Painted Pony in the fourth quarter of 2020, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity loss on the Company's interest in NWRP.
- **Income tax expense** – 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 in the first quarter of 2021, partially in response to the OPEC+ decision to maintain production cut agreements implemented in the first half of 2020. Additionally, global demand for crude oil increased due to improved economic conditions, partially as a result of the availability of COVID-19 vaccines. WTI benchmark pricing averaged US$57.80 per bbl and the WCS Heavy Differential averaged US$12.42 per bbl in the first quarter of 2021. Economic conditions and the outlook for crude oil prices remain somewhat uncertain due to the impact of recent COVID-19 variants of concern and the timing of the roll-out of vaccines, which have the potential to delay the recovery of global economic conditions.

The Company continues to be nimble and act decisively to address the impacts of COVID-19 on its business and make appropriate operational improvements to increase efficiencies, including the optimization of the production profile across its diverse asset base and through its focus on cost control and efficiencies. The Company is also working diligently to reduce production costs wherever possible, asking all stakeholders to contribute to the sustainability of operations.

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

Liquidity

As at March 31, 2021, the Company had undrawn revolving bank credit facilities of $4,959 million. Including cash and cash equivalents and short-term investments, the Company had approximately $5,547 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit. At March 31, 2021, the Company had $145 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

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 December 9, 2020, the Company announced its 2021 capital budget targeted at approximately $3,205 million, of which $1,345 million is related to conventional and unconventional assets and $1,860 million is allocated to long-life low decline assets. Production for 2021 is targeted between 1,190,000 BOE/d and 1,260,000 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 2021 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.

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.

Benchmark Commodity Prices

(Average for the period)	Three Months Ended **Mar 31 2021**	Dec 31 2020	Mar 31 2020
WTI benchmark price (US$/bbl)	**$ 57.80**	$ 42.67	$ 46.08
Dated Brent benchmark price (US$/bbl)	**$ 60.58**	$ 44.52	$ 50.42
WCS Heavy Differential from WTI (US$/bbl)	**$ 12.42**	$ 9.30	$ 20.47
SCO price (US$/bbl)	**$ 54.30**	$ 39.69	$ 43.39
Condensate benchmark price (US$/bbl)	**$ 57.99**	$ 42.54	$ 45.54
Condensate Differential from WTI (US$/bbl)	**$ (0.19)**	$ 0.13	$ 0.54
NYMEX benchmark price (US$/MMBtu)	**$ 2.69**	$ 2.66	$ 1.95
AECO benchmark price (C$/GJ)	**$ 2.77**	$ 2.62	$ 2.03
US/Canadian dollar average exchange rate (US$)	**$ 0.7900**	$ 0.7674	$ 0.7434

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 highly sensitive to 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.

On January 1, 2019, the Government of Alberta implemented a mandatory curtailment program that was successful in mitigating the discount in crude oil pricing received in Alberta for both light crude oil and heavy crude oil. The curtailment production limits were suspended effective December 1, 2020 and curtailment orders will only be issued in 2021 if deemed necessary by the Government of Alberta.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$57.80 per bbl for the first quarter of 2021, an increase of 25% from US$46.08 per bbl for the first quarter of 2020, and an increase of 35% from US$42.67 per bbl for the fourth quarter of 2020.

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$60.58 per bbl for the first quarter of 2021, an increase of 20% from US$50.42 per bbl for the first quarter of 2020, and an increase of 36% from US$44.52 per bbl for the fourth quarter of 2020.

The increase in WTI and Brent pricing for the first quarter of 2021 from the comparable periods reflected the OPEC+ decision to maintain production cut agreements implemented in the first half of 2020. Additionally, global demand for crude oil increased due to improved economic conditions, partially as a result of the availability of COVID-19 vaccines.

The WCS Heavy Differential averaged US$12.42 per bbl for the first quarter of 2021, narrowing by 39% from US$20.47 per bbl for the first quarter of 2020, and widening by 34% from US$9.30 per bbl for the fourth quarter of 2020. The narrowing of the WCS Heavy Differential for the first quarter of 2021 from the first quarter of 2020 primarily reflected continued recovery in North American refining demand. The widening of the WCS Heavy Differential for the first quarter of 2021 from the fourth quarter of 2020 primarily reflected increased supply from the Basin due to the suspension of mandatory Government of Alberta curtailment, effective December 1, 2020.

The SCO price averaged US$54.30 per bbl for the first quarter of 2021, an increase of 25% from US$43.39 per bbl for the first quarter of 2020, and an increase of 37% from US$39.69 per bbl for the fourth quarter of 2020. The increase in SCO pricing for the first quarter of 2021 from the comparable periods of 2020 primarily reflected an increase in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.69 per MMBtu for the first quarter of 2021, an increase of 38% from US$1.95 per MMBtu for the first quarter of 2020, and comparable with US$2.66 per MMBtu for the fourth quarter of 2020. The increase in NYMEX natural gas prices for the first quarter of 2021 from the first quarter of 2020 primarily reflected increased domestic demand and LNG exports, together with lower production levels.

AECO natural gas prices averaged $2.77 per GJ for the first quarter of 2021, an increase of 36% from $2.03 per GJ for the first quarter of 2020, and an increase of 6% from $2.62 per GJ for the fourth quarter of 2020. The increase in AECO natural gas prices for the first quarter of 2021 from the comparable periods primarily reflected increased intra-provincial and export demand.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**478,736**	475,889	456,877
North America – Oil Sands Mining and Upgrading (1)	**468,803**	417,089	438,101
North Sea	**19,959**	17,057	27,755
Offshore Africa	**11,854**	17,155	15,943
	979,352	927,190	938,676
Natural gas (MMcf/d)			
North America	**1,585**	1,623	1,407
North Sea	**4**	4	23
Offshore Africa	**9**	17	10
	1,598	1,644	1,440
Total barrels of oil equivalent (BOE/d)	**1,245,703**	1,201,198	1,178,752
Product mix			
Light and medium crude oil and NGLs	**10%**	10%	11%
Pelican Lake heavy crude oil	**4%**	5%	5%
Primary heavy crude oil	**5%**	5%	7%
Bitumen (thermal oil)	**22%**	22%	20%
Synthetic crude oil (1)	**38%**	35%	37%
Natural gas	**21%**	23%	20%
Percentage of gross revenue (1) (2) (excluding Midstream and Refining revenue)			
Crude oil and NGLs	**92%**	90%	92%
Natural gas	**8%**	10%	8%

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

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

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**422,124**	433,697	414,460
North America – Oil Sands Mining and Upgrading	**448,315**	411,640	432,936
North Sea	**19,927**	17,023	27,693
Offshore Africa	**11,325**	16,416	15,296
	901,691	878,776	890,385
Natural gas (MMcf/d)			
North America	**1,508**	1,553	1,374
North Sea	**4**	4	23
Offshore Africa	**9**	16	10
	1,521	1,573	1,407
Total barrels of oil equivalent (BOE/d)	**1,155,220**	1,141,022	1,124,839

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 first quarter of 2021 averaged 979,352 bbl/d, an increase of 4% from 938,676 bbl/d for the first quarter of 2020, and an increase 6% from 927,190 bbl/d for the fourth quarter of 2020. Crude oil and NGLs production in North America Exploration and Production and Oil Sands Mining and Upgrading segments for the comparable periods in 2020 reflected the impact of the Company's curtailment optimization strategy during mandatory Government of Alberta curtailment. Production in the first quarter of 2021 primarily reflected high utilization in the Oil Sands Mining and Upgrading segment and strong thermal oil production following the suspension of mandatory Government of Alberta curtailment on December 1, 2020.

Natural gas production before royalties for the first quarter of 2021 of 1,598 MMcf/d increased 11% from 1,440 MMcf/d for the first quarter of 2020, and was comparable with 1,644 MMcf/d for the fourth quarter of 2020. The increase in natural gas production for the first quarter of 2021 from the first quarter of 2020 primarily reflected production volumes from the acquisition of Painted Pony on October 6, 2020, partially offset by natural field declines. Natural gas production also reflected a decrease of approximately 37 MMcf/d in the first quarter of 2021 due to a labour stoppage at the Pine River gas plant. Due to the poor economics at the facility, the Company anticipates that the plant will be placed in a decommissioned state, and remain offline indefinitely.

Annual crude oil and NGLs production for 2021 is targeted to average between 920,000 bbl/d and 980,000 bbl/d. Annual natural gas production for 2021 is targeted to average between 1,620 MMcf/d and 1,680 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 first quarter of 2021 of 478,736 bbl/d increased 5% from 456,877 bbl/d for the first quarter of 2020, and was comparable with 475,889 bbl/d for the fourth quarter of 2020. The increase in crude oil and NGLs production for the first quarter of 2021 from the first quarter of 2020 primarily reflected the impact of the suspension of mandatory Government of Alberta curtailment on December 1, 2020.

Thermal oil production before royalties for the first quarter of 2021 averaged 267,530 bbl/d, an increase of 17% from 228,303 bbl/d for the first quarter of 2020, and comparable with 266,179 bbl/d for the fourth quarter of 2020. The increase in thermal oil production for the first quarter of 2021 from the first quarter of 2020 reflected the impact of the Company's curtailment optimization strategy in the first quarter of 2020. Production in the first quarter of 2021 reflected high utilization at Jackfish and increased volumes at Kirby North following the suspension of mandatory Government of Alberta curtailment on December 1, 2020.

Pelican Lake heavy crude oil production before royalties averaged 55,498 bbl/d for the first quarter of 2021, a decrease of 4% from 57,986 bbl/d for the first quarter of 2020, and was comparable with 56,036 bbl/d for the fourth quarter of 2020, demonstrating Pelican Lake's long-life low decline production.

Natural gas production before royalties for the first quarter of 2021 averaged 1,585 MMcf/d, an increase of 13% from 1,407 MMcf/d for the first quarter of 2020, and comparable with 1,623 MMcf/d for the fourth quarter of 2020. The increase in natural gas production for the first quarter of 2021 from the first quarter of 2020 primarily reflected production volumes from the acquisition of Painted Pony on October 6, 2020, partially offset by the impact of natural field declines. Natural gas production also reflected a decrease of approximately 37 MMcf/d in the first quarter of 2021 due to a labour stoppage at the Pine River gas plant. Due to the poor economics at the facility, the Company anticipates that the plant will be placed in a decommissioned state, and remain offline indefinitely.

North America – Oil Sands Mining and Upgrading

Record SCO production before royalties for the first quarter of 2021 of 468,803 bbl/d increased 7% from 438,101 bbl/d for the first quarter of 2020 and increased 12% from 417,089 bbl/d for the fourth quarter of 2020. The increase in SCO production for the first quarter of 2021 from the comparable periods primarily reflected the completion of planned turnaround activities at Horizon early in the fourth quarter of 2020, and high utilization and operational enhancements at AOSP following the completion of expansion activities.

North Sea

North Sea crude oil production before royalties for the first quarter of 2021 decreased 28% to 19,959 bbl/d from 27,755 bbl/d for the first quarter of 2020 and increased 17% from 17,057 bbl/d for the fourth quarter of 2020. The decrease in production for the first quarter of 2021 from the first quarter of 2020 primarily reflected the permanent cessation of production at the Banff and Kyle fields on June 1, 2020 and natural field declines. The increase in production from the fourth quarter of 2020 primarily reflected the impact of planned turnaround activities during the fourth quarter of 2020, partially offset by natural field declines.

Offshore Africa

Offshore Africa crude oil production before royalties for the first quarter of 2021 of 11,854 bbl/d decreased 26% from 15,943 bbl/d for the first quarter of 2020 and decreased 31% from 17,155 bbl/d for the fourth quarter of 2020. The decrease in production for the first quarter of 2021 from the first quarter of 2020 primarily reflected planned turnaround activities at Baobab and natural field declines. The decrease in production for the first quarter of 2021 from the fourth quarter of 2020 primarily reflected planned turnaround activities at Baobab and an unplanned outage at Espoir during the first quarter of 2021.

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)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
North Sea	**—**	450,889	—
Offshore Africa	**612,242**	521,244	532,347
	612,242	972,133	532,347

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	**$ 52.68**	$ 40.56	$ 25.90
Transportation (3)	**3.56**	3.81	3.87
Realized sales price, net of transportation	**49.12**	36.75	22.03
Royalties	**5.69**	3.34	2.34
Production expense	**14.56**	12.47	13.71
Netback	**$ 28.87**	$ 20.94	$ 5.98
Natural gas ($/Mcf) (1)			
Sales price (2)	**$ 3.42**	$ 2.94	$ 2.22
Transportation	**0.46**	0.42	0.46
Realized sales price, net of transportation	**2.96**	2.52	1.76
Royalties	**0.16**	0.13	0.05
Production expense	**1.27**	1.10	1.31
Netback	**$ 1.53**	$ 1.29	$ 0.40
Barrels of oil equivalent ($/BOE) (1)			
Sales price (2)	**$ 41.80**	$ 32.61	$ 21.90
Transportation (3)	**3.29**	3.37	3.50
Realized sales price, net of transportation	**38.51**	29.24	18.40
Royalties	**4.10**	2.44	1.70
Production expense	**12.20**	10.43	11.87
Netback	**$ 22.21**	$ 16.37	$ 4.83

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Excludes the impact of a $143 million provision recognized in the fourth quarter of 2020, relating to the Keystone XL pipeline project.

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 50.67**	$ 39.54	$ 23.48
North Sea	**$ 75.16**	$ 56.18	$ 45.85
Offshore Africa	**$ 80.00**	$ 49.05	$ 58.16
Average	**$ 52.68**	$ 40.56	$ 25.90
Natural gas ($/Mcf) (1) (2)			
North America	**$ 3.41**	$ 2.91	$ 2.15
North Sea	**$ 2.57**	$ 1.41	$ 3.75
Offshore Africa	**$ 6.09**	$ 6.64	$ 8.94
Average	**$ 3.42**	$ 2.94	$ 2.22
Average ($/BOE) (1) (2)	**$ 41.80**	$ 32.61	$ 21.90

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

North America

North America realized crude oil prices averaged $50.67 per bbl for the first quarter of 2021, an increase of 116% compared with $23.48 per bbl for the first quarter of 2020 and an increase of 28% compared with $39.54 per bbl for the fourth quarter of 2020. The increase in realized crude oil prices for the first quarter of 2021 from the first quarter of 2020 was primarily due to higher WTI benchmark pricing together with the narrowing of the WCS Heavy Differential. The increase in realized crude oil prices for the first quarter of 2021 from the fourth quarter of 2020 was primarily due to higher WTI benchmark pricing, partially offset by the widening of the WCS Heavy Differential primarily reflecting increased supply from the Basin due to the suspension of mandatory Government of Alberta curtailment, effective December 1, 2020. The Company continues to focus on its crude oil blending marketing strategy and in the first quarter of 2021 contributed approximately 140,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 59% to average $3.41 per Mcf for the first quarter of 2021 from $2.15 per Mcf for the first quarter of 2020 and increased 17% from $2.91 per Mcf for the fourth quarter of 2020. The increase in realized natural gas prices for the first quarter of 2021 from the comparable periods primarily reflected increased intra-provincial and export demand.

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

	Three Months Ended		
(Quarterly average)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 50.54**	$ 38.03	$ 38.15
Pelican Lake heavy crude oil ($/bbl)	**$ 55.26**	$ 43.21	$ 27.75
Primary heavy crude oil ($/bbl)	**$ 54.24**	$ 42.01	$ 25.01
Bitumen (thermal oil) ($/bbl)	**$ 48.92**	$ 38.67	$ 16.53
Natural gas ($/Mcf)	**$ 3.41**	$ 2.91	$ 2.15

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

North Sea

North Sea realized crude oil prices increased 64% to average $75.16 per bbl for the first quarter of 2021 from $45.85 per bbl for the first quarter of 2020 and increased 34% from $56.18 per bbl for the fourth quarter of 2020. Realized crude oil 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 increase in realized crude oil prices for the first quarter of 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 prices increased 38% to average $80.00 per bbl for the first quarter of 2021 from $58.16 per bbl for the first quarter of 2020 and increased 63% from $49.05 per bbl for the fourth quarter of 2020. Realized crude oil 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 increase in realized crude oil prices for the first quarter of 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		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 6.09**	$ 3.52	$ 2.49
North Sea	**$ 0.12**	$ 0.11	$ 0.10
Offshore Africa	**$ 3.57**	$ 2.11	$ 2.36
Average	**$ 5.69**	$ 3.34	$ 2.34
Natural gas ($/Mcf) (1)			
North America	**$ 0.16**	$ 0.13	$ 0.05
Offshore Africa	**$ 0.28**	$ 0.30	$ 0.51
Average	**$ 0.16**	$ 0.13	$ 0.05
Average ($/BOE) (1)	**$ 4.10**	$ 2.44	$ 1.70

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and natural gas royalties for the first quarter of 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 averaged approximately 12% of product sales for the first quarter of 2021 compared with 11% for the first quarter of 2020 and 9% for the fourth quarter of 2020. The increase in royalty rates for the first quarter of 2021 from the comparable periods was primarily due to higher benchmark prices together with fluctuations in the WCS Heavy Differential.

Natural gas royalty rates averaged approximately 5% of product sales for the first quarter of 2021 compared with 2% for the first quarter of 2020 and 4% for the fourth quarter of 2020. The increase in royalty rates for the first quarter of 2021 from the comparable periods was primarily due to higher benchmark pricing.

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 4% for the first quarter of 2021 and was comparable with 4% for the first quarter of 2020 and 4% for the fourth quarter of 2020. 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		
	Mar 31 2021	Dec 31 2020	Mar 31 2020
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 12.80**	$ 10.81	$ 12.69
North Sea	**$ 42.24**	$ 52.42	$ 29.73
Offshore Africa	**$ 16.57**	$ 11.74	$ 11.88
Average	**$ 14.56**	$ 12.47	$ 13.71
Natural gas ($/Mcf) (1)			
North America	**$ 1.24**	$ 1.07	$ 1.24
North Sea	**$ 4.85**	$ 5.29	$ 3.45
Offshore Africa	**$ 4.99**	$ 3.07	$ 5.56
Average	**$ 1.27**	$ 1.10	$ 1.31
Average ($/BOE) (1)	**$ 12.20**	$ 10.43	$ 11.87

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and NGLs production expense for the first quarter of 2021 of $12.80 per bbl was comparable with $12.69 per bbl for the first quarter of 2020 and increased 18% from $10.81 per bbl for the fourth quarter of 2020. The increase in crude oil and NGLs production expense per bbl for the first quarter of 2021 from the comparable periods primarily reflected an increase in energy costs from the first quarter of 2020 and the fourth quarter of 2020, offsetting the impact of cost reductions as a result of the Company’s continuous focus on cost control. The increase in production expense per bbl for the first quarter of 2021 from the fourth quarter of 2020 also reflected seasonal conditions.

North America natural gas production expense for the first quarter of 2021 of $1.24 per Mcf was comparable with $1.24 per Mcf for the first quarter of 2020 and increased 16% from $1.07 per Mcf for the fourth quarter of 2020. The increase in natural gas production expense per Mcf for the first quarter of 2021 from the fourth quarter of 2020 primarily reflected the impact of an increase in electricity costs, together with the impact of seasonal conditions, offsetting the impact of cost reductions as a result of the Company’s continuous focus on cost control.

North Sea

North Sea crude oil production expense for the first quarter of 2021 of $42.24 per bbl increased 42% from $29.73 per bbl for the first quarter of 2020 and decreased 19% from $52.42 per bbl for the fourth quarter of 2020. The increase in crude oil production expense per bbl for the first quarter of 2021 from the first quarter of 2020 was primarily due to lower volumes on a relatively fixed cost base, higher energy costs, and the impact of timing of liftings from various fields that have different cost structures. The decrease in crude oil production expense per bbl for the first quarter of 2021 from the fourth quarter of 2020 was primarily due to higher volumes on a relatively fixed cost base. North Sea production expense also reflected fluctuations in the Canadian dollar.

Offshore Africa

Offshore Africa crude oil production expense for the first quarter of 2021 of $16.57 per bbl increased 39% from $11.88 per bbl for the first quarter of 2020 and increased 41% from $11.74 per bbl for the fourth quarter of 2020. The increase in crude oil production expense per bbl for the first quarter of 2021 from the comparable periods primarily reflected the timing of liftings from various fields that have different cost structures and 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

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
North America	**$ 868**	$ 1,017	$ 955
North Sea	**68**	61	99
Offshore Africa	**31**	54	41
Expense	**$ 967**	$ 1,132	$ 1,095
$/BOE (1)	**$ 13.70**	$ 15.55	$ 15.75

(1) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, depreciation and amortization expense for the first quarter of 2021 of $13.70 per BOE decreased 13% from $15.75 per BOE for the first quarter of 2020 and decreased 12% from $15.55 per BOE for the fourth quarter of 2020. The decrease in depletion, depreciation and amortization expense from the comparable periods primarily reflected lower depletion rates in the North America Exploration and Production segment, including the impact of the acquisition of Painted Pony in the fourth quarter of 2020.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
North America	**$ 25**	$ 24	$ 27
North Sea	**5**	8	7
Offshore Africa	**1**	1	1
Expense	**$ 31**	$ 33	$ 35
$/BOE (1)	**$ 0.45**	$ 0.45	$ 0.50

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

Asset retirement obligation accretion expense for the first quarter of 2021 of $0.45 per BOE decreased 10% from $0.50 per BOE for the first quarter of 2020 and was comparable with $0.45 per BOE for the fourth quarter of 2020. 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 first quarter of 2021 of 468,803 bbl/d reflected high utilization at Horizon and operational enhancements at AOSP following the completion of expansion activities.

The Company incurred production costs, excluding natural gas costs, of $779 million ($18.42 per bbl) for the first quarter of 2021, a 6% increase (2% decrease per bbl) from the fourth quarter of 2020.

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

	Three Months Ended		
($/bbl) [1]	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
SCO realized sales price [2]	**$ 64.60**	$ 48.56	$ 50.88
Bitumen value for royalty purposes [3]	**$ 46.39**	$ 34.70	$ 16.82
Bitumen royalties [4]	**$ 2.88**	$ 0.59	$ 0.87
Transportation	**$ 1.10**	$ 1.36	$ 1.28

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of blending and feedstock costs.

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

(4) Calculated based on bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

The realized SCO sales price averaged $64.60 per bbl for the first quarter of 2021, an increase of 27% from $50.88 per bbl for the first quarter of 2020 and an increase of 33% from $48.56 per bbl for the fourth quarter of 2020. The increase in the realized SCO sales price for the first quarter of 2021 from the comparable periods primarily reflected increases in WTI benchmark pricing.

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 Company's unaudited interim consolidated financial statements.

	Three Months Ended		
($ millions)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Production costs, excluding natural gas costs	**$ 779**	$ 736	$ 773
Natural gas costs	**59**	51	36
Production costs	**$ 838**	$ 787	$ 809

	Three Months Ended		
($/bbl) [1]	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Production costs, excluding natural gas costs	**$ 18.42**	$ 18.89	$ 19.83
Natural gas costs	**1.40**	1.31	0.93
Production costs	**$ 19.82**	$ 20.20	$ 20.76
Sales (bbl/d)	**469,953**	423,438	428,515

(1) Amounts expressed on a per unit basis are based on sales volumes.

Production costs for the first quarter of 2021 averaged $19.82 per bbl, a decrease of 5% from $20.76 per bbl for the first quarter of 2020 and a decrease of 2% from $20.20 per bbl for the fourth quarter of 2020. The decrease in production costs per bbl for the first quarter of 2021 from the comparable periods primarily reflected higher reliability and operational enhancements at both Horizon and AOSP, offsetting the impact of higher energy costs, including natural gas costs, in the first quarter of 2021. The Company continued to focus on cost control and efficiencies across the entire asset base.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions, except per bbl amounts)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Expense	**$ 450**	$ 479	$ 440
$/bbl (1)	**$ 10.64**	$ 12.31	$ 11.28

(1) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, depreciation and amortization expense for the first quarter of 2021 of $10.64 per bbl decreased 6% from $11.28 per bbl for the first quarter of 2020 and decreased 14% from $12.31 per bbl for the fourth quarter of 2020. Fluctuations in depletion, depreciation and amortization on a per barrel basis primarily reflect fluctuating sales volumes from different underlying operations.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions, except per bbl amounts)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Expense	**$ 15**	$ 18	$ 17
$/bbl (1)	**$ 0.34**	$ 0.47	$ 0.44

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

Asset retirement obligation accretion expense of $0.34 per bbl for the first quarter of 2021 decreased 23% from $0.44 per bbl for the first quarter of 2020 and decreased 28% from $0.47 per bbl for the fourth quarter of 2020. Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

MIDSTREAM AND REFINING

	Three Months Ended		
($ millions)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Product sales			
Crude oil and NGLs, midstream activities	**$ 19**	$ 21	$ 21
NWRP, refined product sales	**131**	99	—
Segmented revenue	**150**	120	21
Less:			
Production expense			
NWRP, refining toll	**58**	72	—
Midstream	**5**	3	6
NWRP, transportation and feedstock costs	**105**	83	—
Depreciation	**4**	4	4
Segment earnings (loss) before taxes	**$ (22)**	$ (42)	$ 11

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% interest in NWRP.

NWRP operates a 50,000 bbl/d bitumen upgrader and refinery that targets to process 12,500 bbl/d of bitumen feedstock for the Company and 37,500 bbl/d of bitumen feedstock for the Alberta Petroleum Marketing Commission, an agent of the Government of Alberta, under a 30-year fee-for-service tolling agreement.

On June 1, 2020, the refinery achieved the Commercial Operation Date, pursuant to the terms of the tolling agreement. The Company is unconditionally obligated to pay its 25% pro rata share of the debt tolls over the 30-year tolling period. For the first quarter of 2021, production of ultra-low sulphur diesel and other refined products averaged 56,316 BOE/d (14,079 BOE/d to the Company).

The Company's unrecognized share of the equity (income) loss from NWRP for the first quarter of 2021 was a recovery of unrecognized losses of $17 million (three months ended March 31, 2020 – unrecognized equity loss of $93 million). As at March 31, 2021, the cumulative unrecognized share of losses from NWRP was $136 million (December 31, 2020 – $153 million).

ADMINISTRATION EXPENSE

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Expense	**$ 95**	$ 107	$ 108
$/BOE [1]	**$ 0.84**	$ 0.96	$ 1.00

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense for the first quarter of 2021 of $0.84 per BOE decreased 16% from $1.00 per BOE for the first quarter of 2020 and decreased 13% from $0.96 per BOE for the fourth quarter of 2020. Administration expense per BOE decreased for the first quarter of 2021 from the comparable periods primarily due to the impact of lower personnel and corporate costs and higher sales volumes.

SHARE-BASED COMPENSATION

	Three Months Ended		
($ millions)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Expense (recovery)	**$ 129**	$ 123	$ (223)

The Company’s Stock Option Plan provides employees with the right to receive common shares or a cash payment in exchange for stock options surrendered. The 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 recorded a $129 million share-based compensation expense for the first quarter of 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. Included within the share-based compensation expense for the first quarter of 2021 was $14 million related to PSUs granted to certain executive employees (March 31, 2020 – $7 million recovery). For the first quarter of 2021, the Company charged $1 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (March 31, 2020 – $1 million charged).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended		
($ millions, except per BOE amounts and interest rates)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Expense, gross	**$ 185**	$ 180	$ 214
Less: capitalized interest	**—**	3	8
Expense, net	**$ 185**	$ 177	$ 206
$/BOE [1]	**$ 1.64**	$ 1.59	$ 1.90
Average effective interest rate	**3.4%**	3.3%	3.9%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Net interest and other financing expense per BOE for the first quarter of 2021 decreased 14% to $1.64 per BOE from $1.90 per BOE for the first quarter of 2020 and increased 3% from $1.59 per BOE for the fourth quarter of 2020. The decrease in interest expense per BOE for the first quarter of 2021 from the first quarter of 2020 primarily reflected lower benchmark interest rates and lower average debt levels in the first quarter of 2021. The increase in interest expense per BOE for the first quarter of 2021 from the fourth quarter of 2020 was primarily due to higher benchmark interest rates in the first quarter of 2021.

The Company's average effective interest rate for the first quarter of 2021 decreased from the first quarter of 2020 primarily due to the impact of lower benchmark interest rates on the Company's outstanding bank credit facilities.

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.

	Three Months Ended		
($ millions)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Foreign currency contracts	**$ 15**	$ 25	$ (57)
Natural gas financial instruments	**(6)**	(2)	10
Realized loss (gain)	**9**	23	(47)
Foreign currency contracts	**(5)**	6	(9)
Natural gas financial instruments	**25**	(27)	(8)
Unrealized loss (gain)	**20**	(21)	(17)
Net loss (gain)	**$ 29**	$ 2	$ (64)

During the first quarter of 2021, the net realized risk management losses were related to the settlement of foreign currency contracts, partially offset by gains on natural gas financial instruments. The Company recorded a net unrealized loss of $20 million ($15 million after-tax) on its risk management activities for the first quarter of 2021 (three months ended December 31, 2020 – unrealized gain of $21 million; $16 million after-tax; three months ended March 31, 2020 – unrealized gain of $17 million; $15 million after-tax).

Further details related to outstanding derivative financial instruments at March 31, 2021 are disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended		
($ millions)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Net realized loss (gain)	**$ 10**	$ 21	$ (199)
Net unrealized (gain) loss	**(172)**	(534)	1,121
Net (gain) loss (1)	**$ (162)**	$ (513)	$ 922

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

The net realized foreign exchange loss for the first quarter of 2021 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling during the quarter. The net unrealized foreign exchange gain for the first quarter of 2021 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss for each of the periods presented reflected the impact of the cross currency swaps, including the settlement of US$500 million in cross currency swaps during the first quarter of 2020 (three months ended March 31, 2021 – unrealized loss of $10 million, three months ended December 31, 2020 – unrealized loss of $32 million, three months ended March 31, 2020 – unrealized loss of $74 million). The US/Canadian dollar exchange rate at March 31, 2021 was US$0.7954 (December 31, 2020 – US$0.7840, March 31, 2020 – US$0.7082).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Mar 31 2021**	Dec 31 2020	Mar 31 2020
North America [1]	**$ 285**	$ 42	$ (194)
North Sea	**11**	—	9
Offshore Africa	**4**	5	4
PRT [2] – North Sea	**(5)**	(14)	—
Other taxes	**2**	2	2
Current income tax expense (recovery)	**297**	35	(179)
Deferred income tax expense (recovery)	**21**	(25)	20
	$ 318	$ 10	$ (159)
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**21%**	24%	36%

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

(2) Petroleum Revenue Tax.

(3) Excludes the impact of current and deferred PRT and other current income tax.

The effective income tax rate for the first quarter of 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 first quarter of 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 [1]

($ millions)	Three Months Ended Mar 31 2021	Dec 31 2020	Mar 31 2020
Exploration and Evaluation			
Net property dispositions	**$ —**	$ (1)	$ (18)
Net expenditures	**4**	9	25
Total Exploration and Evaluation	**4**	8	7
Property, Plant and Equipment			
Net property acquisitions [2]	**1**	522	13
Well drilling, completion and equipping	**266**	115	202
Production and related facilities	**192**	131	214
Capitalized interest and other	**13**	20	12
Total Property, Plant and Equipment	**472**	788	441
Total Exploration and Production	**476**	796	448
Oil Sands Mining and Upgrading			
Project costs	**41**	86	56
Sustaining capital	**186**	212	201
Turnaround costs	**29**	22	23
Capitalized interest and other	**1**	4	9
Total Oil Sands Mining and Upgrading	**257**	324	289
Midstream and Refining	**2**	1	1
Abandonments [3]	**67**	52	89
Head office	**6**	3	11
Total net capital expenditures	**$ 808**	$ 1,176	$ 838
By segment			
North America [2]	**$ 419**	$ 729	$ 395
North Sea	**32**	34	26
Offshore Africa	**25**	33	27
Oil Sands Mining and Upgrading	**257**	324	289
Midstream and Refining	**2**	1	1
Abandonments [3]	**67**	52	89
Head office	**6**	3	11
Total	**$ 808**	$ 1,176	$ 838

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

(3) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table and are net of the impact of government grant income under the provincial well-site rehabilitation programs.

Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities

	Three Months Ended		
($ millions)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Cash flows used in investing activities	***$ 648***	*$ 624*	*$ 859*
Net change in non-cash working capital	***93***	*(21)*	*(110)*
Repayment of NWRP subordinated debt advances (1)	**—**	*124*	—
Abandonment expenditures (2)	***67***	*52*	*89*
Other (3)	**—**	*397*	—
Net capital expenditures	***$ 808***	*$ 1,176*	*$ 838*

(1) Relates to a partial repayment of the Company's subordinated debt advances to NWRP.

(2) The Company excludes abandonment expenditures from "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" in the "Financial Highlights" section of this MD&A and are net of the impact of government grant income under the provincial well-site rehabilitation programs.

(3) Relates to the settlement of long-term debt assumed in the acquisition of Painted Pony in the fourth quarter of 2020.

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 first quarter of 2021 were $808 million compared with $838 million for the first quarter of 2020 and $1,176 million for the fourth quarter of 2020.

2021 Capital Budget

On December 9, 2020, the Company announced its 2021 capital budget targeted at approximately $3,205 million, of which $1,345 million is related to conventional and unconventional assets and $1,860 million is allocated to long-life low decline assets.

Drilling Activity (1)

	Three Months Ended		
(number of wells)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Net successful natural gas wells	**22**	9	11
Net successful crude oil wells (2)	**44**	5	35
Stratigraphic test / service wells	**328**	—	367
Total	**394**	14	413
Success rate (excluding stratigraphic test / service wells)	**100%**	100%	100%

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

(2) Includes bitumen wells.

North America

During the first quarter of 2021, the Company targeted 22 net natural gas wells, 27 net primary heavy crude oil wells, 3 net bitumen (thermal oil) wells and 12 net light crude oil wells.

North Sea

During the first quarter of 2021, the Company targeted 2 net light crude oil wells in the North Sea.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Mar 31 2021**	Dec 31 2020	Mar 31 2020
Working capital (1)	**$ 626**	$ 626	$ 683
Long-term debt (2) (3)	**$ 20,009**	$ 21,453	$ 22,687
Less: cash and cash equivalents	**166**	184	1,071
Long-term debt, net	**$ 19,843**	$ 21,269	$ 21,616
Share capital	**$ 9,685**	$ 9,606	$ 9,517
Retained earnings	**23,567**	22,766	23,425
Accumulated other comprehensive (loss) income	**(21)**	8	320
Shareholders' equity	**$ 33,231**	$ 32,380	$ 33,262
Debt to book capitalization (3) (4)	**37.4%**	39.6%	39.4%
Debt to market capitalization (3) (5)	**30.1%**	37.0%	48.7%
After-tax return on average common shareholders' equity (6)	**6.8%**	(1.3)%	9.4%
After-tax return on average capital employed (3) (7)	**5.1%**	0.2%	6.8%

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

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

(3) Long-term debt is stated at its carrying value, net of original issue discounts and premiums and transaction costs.

(4) Calculated as net current and long-term debt; divided by the book value of common shareholders' equity plus net current and long-term debt.

(5) Calculated as net current and long-term debt; divided by the market value of common shareholders' equity plus net current and long-term debt.

(6) Calculated as net earnings (loss) for the twelve month trailing period; as a percentage of average common shareholders' equity for the twelve month trailing period.

(7) 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.

As at March 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 first quarter of 2021, the $1,000 million non-revolving term credit facility, originally due February 2022, was extended to February 2023.
  - During 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon. During 2020, the Company repaid $162.5 million related to the required annual amortization. During the first quarter of 2021, the Company repaid a further $962.5 million on the facility, reducing the outstanding balance to $2,125 million, and exceeding the required annual amortization of $162.5 million originally due in June 2021. Subsequent to March 31, 2021, the Company repaid a further $650 million on the facility, reducing the outstanding balance to $1,475 million. The facility matures in June 2022.
  - As at March 31, 2021, the Company had $2,200 million remaining on its 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 2021. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
  - As at March 31, 2021, the Company had US$1,900 million remaining on its 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 2021. 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.
  - Borrowings under the non-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. As at March 31, 2021, the non-revolving term credit facilities were fully drawn.
  - Each of the $2,425 million revolving credit facilities is 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 is 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.
  - 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 March 31, 2021, the Company had undrawn revolving bank credit facilities of $4,959 million. Including cash and cash equivalents and short-term investments, the Company had approximately $5,547 million in liquidity. Additionally, the Company had in place fully drawn term credit facilities of $5,775 million. The Company also has certain other dedicated credit facilities supporting letters of credit. At March 31, 2021, the Company had $145 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

As at March 31, 2021, the Company had total US dollar denominated debt with a carrying amount of $15,785 million (US$12,555 million), before transaction costs and original issue discounts. This included $5,475 million (US$4,355 million) hedged by way of a cross currency swap (US$550 million) and foreign currency forwards (US$3,805 million). The fixed repayment amount of these hedging instruments is $5,419 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $56 million to $15,729 million as at March 31, 2021.

Net long-term debt was $19,843 million at March 31, 2021, resulting in a debt to book capitalization ratio of 37.4% (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 March 31, 2021 are discussed in note 8 of the Company's unaudited interim consolidated financial statements.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at March 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 March 31, 2021 are discussed in note 15 of the Company's unaudited interim consolidated financial statements.

The maturity dates of long-term debt and other long-term liabilities and related interest payments were as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Long-term debt [1]	$	1,772	$	7,024	$	3,138	$	8,178
Other long-term liabilities [2]	$	236	$	193	$	415	$	910
Interest and other financing expense [3]	$	747	$	659	$	1,553	$	4,266

(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, $186 million; one to less than two years, $155 million; two to less than five years, $399 million; and thereafter, $910 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 March 31, 2021.

Share Capital

As at March 31, 2021, there were 1,185,685,000 common shares outstanding (December 31, 2020 – 1,183,866,000 common shares) and 56,293,000 stock options outstanding. As at May 4, 2021, the Company had 1,184,837,000 common shares outstanding and 55,757,000 stock options outstanding.

On March 3, 2021, the Board of Directors approved an increase in the quarterly dividend to $0.47 per common share, beginning with the dividend payable on April 5, 2021 (previous quarterly dividend rate of $0.425 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, alternative Canadian trading platforms, and the New York Stock Exchange, up to 59,278,474 common shares, over a 12-month period commencing March 11, 2021 and ending March 10, 2022.

For the three months ended March 31, 2021, the Company purchased 600,000 common shares at a weighted average price of $38.61 per common share for a total cost of $23 million. Retained earnings were reduced by $18 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2021, the Company purchased 960,000 common shares at a weighted average price of $38.15 per common share for a total cost of $37 million.

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 March 31, 2021:

		Remaining 2021		2022		2023		2024		2025		Thereafter
Product transportation and processing [1]	$	661	$	826	$	879	$	842	$	809	$	10,365
North West Redwater Partnership service toll [2]	$	122	$	156	$	159	$	156	$	149	$	2,642
Offshore vessels and equipment	$	48	$	41	$	—	$	—	$	—	$	—
Field equipment and power	$	19	$	21	$	21	$	21	$	21	$	246
Other	$	18	$	21	$	20	$	21	$	21	$	16

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

(2) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt component of the monthly cost of service tolls. Included in the cost of service tolls is $1,092 million of interest payable over the 30-year tolling period.

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.

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 ended March 31, 2021, COVID-19 continued to have an impact on the global economy, including the oil and gas industry. Business conditions in the first quarter of 2021 continued to reflect the market uncertainty associated with COVID-19, with some improvements to global crude oil demand and supply conditions. 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 three months ended March 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.