Canadian Natural Resources Limited

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS AND YEAR ENDED DECEMBER 31, 2020

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 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 and year ended December 31, 2020 and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2019. 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 and year ended December 31, 2020 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 and year ended December 31, 2020 in relation to the comparable periods in 2019 and the third 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, 2019, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Information on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated March 3, 2021.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Dec 31 2020	Sep 30 2020	Dec 31 2019	Year Ended Dec 31 2020	Dec 31 2019
Product sales [(1)]	**$ 5,219**	$ 4,676	$ 6,335	**$ 17,491**	$ 24,394
Crude oil and NGLs	**$ 4,592**	$ 4,202	$ 5,947	**$ 15,579**	$ 22,950
Natural gas	**$ 496**	$ 338	$ 382	**$ 1,478**	$ 1,419
Net earnings (loss)	**$ 749**	$ 408	$ 597	**$ (435)**	$ 5,416
Per common share – basic	**$ 0.63**	$ 0.35	$ 0.50	**$ (0.37)**	$ 4.55
– diluted	**$ 0.63**	$ 0.35	$ 0.50	**$ (0.37)**	$ 4.54
Adjusted net earnings (loss) from operations [(2)]	**$ 176**	$ 135	$ 686	**$ (756)**	$ 3,795
Per common share – basic	**$ 0.15**	$ 0.11	$ 0.58	**$ (0.64)**	$ 3.19
– diluted	**$ 0.15**	$ 0.11	$ 0.58	**$ (0.64)**	$ 3.18
Cash flows from operating activities	**$ 1,270**	$ 2,070	$ 2,454	**$ 4,714**	$ 8,829
Adjusted funds flow [(3)]	**$ 1,708**	$ 1,740	$ 2,494	**$ 5,200**	$ 10,267
Per common share – basic	**$ 1.45**	$ 1.47	$ 2.11	**$ 4.40**	$ 8.62
– diluted	**$ 1.44**	$ 1.47	$ 2.10	**$ 4.40**	$ 8.61
Cash flows used in investing activities	**$ 624**	$ 643	$ 854	**$ 2,819**	$ 7,255
Net capital expenditures [(4)]	**$ 1,176**	$ 771	$ 1,056	**$ 3,206**	$ 7,121

(1) Further details related to product sales are disclosed in note 18 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 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, and other. The Company considers net capital expenditures a key measure 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)

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Net earnings (loss)	***$ 749***	*$ 408*	*$ 597*	***$ (435)***	*$ 5,416*
Share-based compensation, net of tax (1)	***117***	*(5)*	*148*	***(86)***	*210*
Unrealized risk management (gain) loss, net of tax (2)	***(16)***	*(1)*	*16*	***(31)***	*14*
Unrealized foreign exchange gain, net of tax (3)	***(534)***	*(270)*	*(225)*	***(116)***	*(548)*
Realized foreign exchange gain on settlement of cross currency swaps, net of tax (4)	**—**	—	—	***(166)***	—
Gain on acquisition, net of tax (5)	***(217)***	—	—	***(217)***	—
(Gain) loss from investments, net of tax (6) (7)	***(33)***	*3*	*150*	***185***	*321*
Provision for pipeline project, net of tax (8)	***110***	—	—	***110***	—
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (9)	**—**	—	—	**—**	*(1,618)*
Adjusted net earnings (loss) from operations	***$ 176***	*$ 135*	*$ 686*	***$ (756)***	*$ 3,795*

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("PSU") plan. The Company's Stock Option Plan provides for a cash payment option. 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. Accordingly, the fair value of the outstanding vested options 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 crude oil, 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 investment in the 50% owned NWRP is accounted for using the equity method of accounting. Included in the non-cash loss from investments is the Company's pro rata share of NWRP's equity loss recognized for the period.

(7) 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).

(8) 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.

(9) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to the underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recognized in net earnings (loss) during the period the legislation is substantively enacted. In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of this corporate income tax rate reduction, the Company's deferred corporate income tax liability decreased by $1,618 million for the year ended December 31, 2019. In the fourth quarter of 2020, the Government of Alberta substantively enacted legislation to accelerate this reduction, lowering the corporate tax rate from 10% to 8%, effective July 1, 2020. This acceleration did not have a significant impact on the Company's deferred corporate income tax liability for the year ended December 31, 2020.

Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Cash flows from operating activities	***$ 1,270***	*$ 2,070*	*$ 2,454*	***$ 4,714***	*$ 8,829*
Net change in non-cash working capital	***394***	*(372)*	*(52)*	***166***	*1,033*
Abandonment expenditures (1)	***52***	*68*	*84*	***249***	*296*
Other (2)	***(8)***	*(26)*	*8*	***71***	*109*
Adjusted funds flow	***$ 1,708***	*$ 1,740*	*$ 2,494*	***$ 5,200***	*$ 10,267*

(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.

(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

The net loss for the year ended December 31, 2020 was $435 million compared with net earnings of $5,416 million for the year ended December 31, 2019. The net loss for the year ended December 31, 2020 included net after-tax income of $321 million compared with net after-tax income of $1,621 million for the year ended December 31, 2019 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 loss from investments, a provision relating to the Keystone XL pipeline project, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, the adjusted net loss from operations for the year ended December 31, 2020 was $756 million compared with adjusted net earnings from operations of $3,795 million for the year ended December 31, 2019.

Net earnings for the fourth quarter of 2020 were $749 million compared with net earnings of $597 million for the fourth quarter of 2019 and net earnings of $408 million for the third quarter of 2020. Net earnings for the fourth quarter of 2020 included net after-tax income of $573 million compared with net after-tax expenses of $89 million for the fourth quarter of 2019 and net after-tax income of $273 million for the third quarter of 2020 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the gain on acquisition, the (gain) loss from investments, and a provision relating to the Keystone XL pipeline project. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2020 were $176 million compared with adjusted net earnings from operations of $686 million for the fourth quarter of 2019 and adjusted net earnings from operations of $135 million for the third quarter of 2020.

The net loss and the adjusted net loss from operations for the year ended December 31, 2020 compared with net earnings and adjusted net earnings from operations for the year ended December 31, 2019 primarily reflected:

- lower crude oil and NGLs netbacks in the Exploration and Production segments;
- lower realized SCO prices in the Oil Sands Mining and Upgrading segment; and
- higher depletion, depreciation and amortization;

partially offset by:

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

Net earnings and adjusted net earnings from operations for the fourth quarter of 2020 compared with net earnings and adjusted net earnings from operations for the fourth quarter of 2019 primarily reflected:

- lower crude oil and NGLs netbacks in the Exploration and Production segments; and
- lower realized SCO sales prices in the Oil Sands Mining and Upgrading segment;

partially offset by:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower SCO production costs in the Oil Sands Mining and Upgrading segment;
- higher natural gas sales volumes in the Exploration and Production segments; and
- higher natural gas netbacks in the Exploration and Production segments.

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

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower SCO production costs per bbl in the Oil Sands Mining and Upgrading segment;
- higher natural gas sales volumes in the Exploration and Production segments; and
- higher natural gas netbacks in the Exploration and Production segments;

partially offset by:

- lower crude oil and NGLs netbacks in the Exploration and Production segments.

The impacts of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the gain on acquisition, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities also contributed to the movements in net earnings (loss) from the comparable periods. These items are discussed in detail in the relevant sections of this MD&A.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the year ended December 31, 2020 were $4,714 million compared with $8,829 million for the year ended December 31, 2019. Cash flows from operating activities for the fourth quarter of 2020 were $1,270 million compared with $2,454 million for the fourth quarter of 2019 and $2,070 million for the third 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 net earnings (loss) and adjusted net earnings (loss) from operations (excluding the effects of depletion, depreciation and amortization, the gain on acquisition and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities), as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the year ended December 31, 2020 was $5,200 million compared with $10,267 million for the year ended December 31, 2019. Adjusted funds flow for the fourth quarter of 2020 was $1,708 million compared with $2,494 million for the fourth quarter of 2019 and $1,740 million for the third 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 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 fourth quarter of 2020 averaged 927,190 bbl/d, comparable with 913,782 bbl/d for the fourth quarter of 2019 and an increase of 5% from 884,342 bbl/d for the third quarter of 2020. Total natural gas production before royalties for the fourth quarter of 2020 increased 13% to 1,644 MMcf/d from 1,455 MMcf/d for the fourth quarter of 2019 and increased 21% from 1,362 MMcf/d for the third quarter of 2020. Total production before royalties for the fourth quarter of 2020 increased 4% to 1,201,198 BOE/d from 1,156,276 BOE/d for the fourth quarter of 2019 and increased 8% from 1,111,286 BOE/d for the third 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 reflects prevailing benchmark pricing. In the Company's Exploration and Production segments, the fourth quarter of 2020 crude oil and NGLs sales price averaged $40.56 per bbl, a decrease of 18% compared with $49.60 per bbl for the fourth quarter of 2019, and comparable with $40.14 per bbl for the third quarter of 2020. The natural gas price increased 11% to average $2.94 per Mcf for the fourth quarter of 2020 from $2.64 per Mcf for the fourth quarter of 2019, and increased 27% from $2.31 per Mcf for the third quarter of 2020. In the Oil Sands Mining and Upgrading segment, the Company's SCO sales price decreased 29% to average $48.56 per bbl for the fourth quarter of 2020 from $68.67 per bbl from the fourth quarter of 2019, and was comparable with $48.92 per bbl for the third 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, fourth quarter of 2020 crude oil and NGLs production expense averaged $12.47 per bbl, comparable with $12.46 for the fourth quarter of 2019, and an increase of 13% from $11.03 per bbl for the third quarter of 2020. Natural gas production expense averaged $1.10 per Mcf for the fourth quarter of 2020, a decrease of 6% from $1.17 per Mcf for the fourth quarter of 2019 and a decrease of 7% from $1.18 per Mcf for the third quarter of 2020. In the Oil Sands Mining and Upgrading segment, production costs averaged $20.20 per bbl for the fourth quarter of 2020, a decrease of 19% from $25.09 per bbl for the fourth quarter of 2019, and a decrease of 15% from $23.81 per bbl for the third 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)		**Dec 31 2020**		Sep 30 2020		Jun 30 2020		Mar 31 2020
Product sales [(1)]	**$**	**5,219**	$	4,676	$	2,944	$	4,652
Crude oil and NGLs	**$**	**4,592**	$	4,202	$	2,462	$	4,323
Natural gas	**$**	**496**	$	338	$	307	$	337
Net earnings (loss)	**$**	**749**	$	408	$	(310)	$	(1,282)
Net earnings (loss) per common share								
– basic	**$**	**0.63**	$	0.35	$	(0.26)	$	(1.08)
– diluted	**$**	**0.63**	$	0.35	$	(0.26)	$	(1.08)
($ millions, except per common share amounts)		Dec 31 2019		Sep 30 2019		Jun 30 2019		Mar 31 2019
Product sales [(1)]	$	6,335	$	6,587	$	5,931	$	5,541
Crude oil and NGLs	$	5,947	$	6,324	$	5,597	$	5,082
Natural gas	$	382	$	257	$	324	$	456
Net earnings (loss)	$	597	$	1,027	$	2,831	$	961
Net earnings (loss) per common share								
– basic	$	0.50	$	0.87	$	2.37	$	0.80
– diluted	$	0.50	$	0.87	$	2.36	$	0.80

(1) Further details related to product sales for the three months ended December 31, 2020 and 2019 are disclosed in note 18 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 decreased significantly in the first half of 2020 due to the erosion of global demand, reflecting the severity of COVID-19 and related economic conditions. In April 2020, in response to the collapse of crude oil prices, OPEC+ agreed to cut production. As the global economy improved in the latter part of the year, OPEC+ agreed to continue with production cuts implemented in the second quarter of 2020. Pricing improved in the fourth quarter of 2020 with WTI benchmark pricing averaging US$42.67 per bbl and the WCS Heavy Differential averaging US$9.30 per bbl. Subsequent to December 31, 2020, Saudi Arabia committed to reduce its production by 1.0 MMbbl/d, which had a further positive impact on crude oil pricing.

Production Flexibility and Cost Control

The Company continues to be nimble and act decisively to make appropriate operational improvements to increase efficiencies and cost control and mitigate the impact of the decline in commodity pricing across all of its operations. To mitigate the impact of realized pricing on certain crude oil products, the Company optimizes the production profile across its diverse asset base. The Company implemented changes to its compensation program in light of current commodity volatility, and these changes had an immediate impact on the Company's costs, effective April 2020. The Company is also working diligently to reduce production costs wherever possible, asking all stakeholders to contribute to the sustainability of operations.

The Company continued to prioritize the optimization of higher value light crude oil, NGLs and SCO, representing approximately 45% of total corporate BOE production volumes for the fourth quarter of 2020. Optimization of production volumes continues to be a key focus of the Company at current commodity price levels.

Production costs throughout 2020 also reflected the impact of measures to promote social distancing and other precautionary measures related to COVID-19 at the Company's head office and field locations, both internationally and in North America. The Company continues to mitigate the impact of these costs through its focus on cost control and efficiencies across the asset base.

Canada Emergency Wage Subsidy

On March 27, 2020, in response to COVID-19, the Government of Canada announced the CEWS. The CEWS enables eligible Canadian employers who have been impacted by COVID-19 to apply for a subsidy of a specified amount of eligible employee wages. The Company continued to be eligible for the subsidy in the fourth quarter of 2020 as its qualifying revenues declined by the specified amount as compared with the prior year reference period.

Liquidity

As at December 31, 2020, the Company had undrawn revolving bank credit facilities of $4,958 million. Including cash and cash equivalents and short-term investments, the Company had approximately $5,447 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit.

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

Capital Spending

Safe, reliable, effective and efficient operations continues 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 information. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Risks and Uncertainties

COVID-19 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 Dec 31 2020	Sep 30 2020	Dec 31 2019	Year Ended Dec 31 2020	Dec 31 2019
WTI benchmark price (US$/bbl)	**$ 42.67**	$ 40.94	$ 56.96	**$ 39.40**	$ 57.04
Dated Brent benchmark price (US$/bbl)	**$ 44.52**	$ 42.74	$ 62.64	**$ 42.27**	$ 64.04
WCS Heavy Differential from WTI (US$/bbl)	**$ 9.30**	$ 9.06	$ 15.84	**$ 12.57**	$ 12.79
SCO price (US$/bbl)	**$ 39.69**	$ 38.61	$ 56.32	**$ 36.26**	$ 56.35
Condensate benchmark price (US$/bbl)	**$ 42.54**	$ 37.55	$ 52.99	**$ 36.97**	$ 52.84
Condensate Differential from WTI (US$/bbl)	**$ 0.13**	$ 3.39	$ 3.97	**$ 2.43**	$ 4.20
NYMEX benchmark price (US$/MMBtu)	**$ 2.66**	$ 1.97	$ 2.50	**$ 2.08**	$ 2.63
AECO benchmark price (C$/GJ)	**$ 2.62**	$ 2.03	$ 2.21	**$ 2.12**	$ 1.54
US/Canadian dollar average exchange rate (US$)	**$ 0.7674**	$ 0.7507	$ 0.7576	**$ 0.7454**	$ 0.7536

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 has been successful in mitigating the discount in crude oil pricing received in Alberta for both light crude oil and heavy crude oil. The Government of Alberta extended the mandatory curtailment program to December 31, 2021; however, 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$39.40 per bbl for the year ended December 31, 2020, a decrease of 31% from US$57.04 per bbl for the year ended December 31, 2019. WTI averaged US$42.67 per bbl for the fourth quarter of 2020, a decrease of 25% from US$56.96 per bbl for the fourth quarter of 2019, and an increase of 4% from US$40.94 per bbl for the third 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$42.27 per bbl for the year ended December 31, 2020, a decrease of 34% from US$64.04 per bbl for the year ended December 31, 2019. Brent averaged US$44.52 per bbl for the fourth quarter of 2020, a decrease of 29% from US$62.64 per bbl for the fourth quarter of 2019, and an increase of 4% from US$42.74 per bbl for the third quarter of 2020.

The decrease in WTI and Brent pricing for the three months and year ended December 31, 2020 from the comparable periods in 2019 primarily reflected significant reductions in refinery utilization due to decreased demand for refined products as a result of COVID-19, resulting in an oversupply of crude oil in the market. The increase in WTI and Brent pricing for the fourth quarter of 2020 from the third quarter of 2020 primarily reflected a partial recovery in global demand and agreements by OPEC+ in the fourth quarter of 2020 to continue with production cuts implemented in the second quarter of 2020.

The WCS Heavy Differential averaged US$12.57 per bbl for the year ended December 31, 2020, comparable with US$12.79 per bbl for the year ended December 31, 2019. The WCS Heavy Differential averaged US$9.30 per bbl for the fourth quarter of 2020, a decrease of 41% from US$15.84 per bbl for the fourth quarter of 2019, and an increase of 3% from US$9.06 per bbl for the third quarter of 2020. The narrowing of the WCS Heavy Differential for the fourth quarter of 2020 from the fourth quarter of 2019 primarily reflected the impact of a significant reduction in supply from the Basin due to planned and unplanned outages, together with the partial recovery in global demand. The slight widening of the WCS Heavy Differential for the fourth quarter of 2020 from the third quarter of 2020 was primarily due to lower seasonal demand in addition to the suspension of mandatory Government of Alberta curtailment, effective

December 1, 2020. The WCS Heavy Differential in the current and the comparable periods reflected the impact of the mandatory curtailment program.

The SCO price averaged US$36.26 per bbl for the year ended December 31, 2020, a decrease of 36% from US$56.35 per bbl for the year ended December 31, 2019. The SCO price averaged US$39.69 per bbl for the fourth quarter of 2020, a decrease of 30% from US$56.32 per bbl for the fourth quarter of 2019, and an increase of 3% from US$38.61 per bbl for the third quarter of 2020. The decrease in SCO pricing for the three months and year ended December 31, 2020 from the comparable periods in 2019 primarily reflected decreases in WTI benchmark pricing. The increase in SCO pricing for the fourth quarter of 2020 from the third quarter of 2020 primarily reflected increases in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.08 per MMBtu for the year ended December 31, 2020, a decrease of 21% from US$2.63 per MMBtu for the year ended December 31, 2019. NYMEX natural gas prices averaged US$2.66 per MMBtu for the fourth quarter of 2020, an increase of 6% from US$2.50 per MMBtu for the fourth quarter of 2019, and an increase of 35% from US$1.97 per MMBtu for the third quarter of 2020. The decrease in NYMEX natural gas prices for the year ended December 31, 2020 from 2019 primarily reflected supply exceeding North American demand due to the impact of COVID-19, and lower Liquefied Natural Gas ("LNG") exports. The increase in NYMEX natural gas prices for the fourth quarter of 2020 from the comparable periods primarily reflected increased domestic demand and LNG exports, together with lower production levels.

AECO natural gas prices averaged $2.12 per GJ for the year ended December 31, 2020, an increase of 38% from $1.54 per GJ for the year ended December 31, 2019. AECO natural gas prices averaged $2.62 per GJ for the fourth quarter of 2020, an increase of 19% from $2.21 per GJ for the fourth quarter of 2019, and an increase of 29% from $2.03 per GJ for the third quarter of 2020. The increase in AECO natural gas prices for the three months and year ended December 31, 2020 from the comparable periods primarily reflected lower production levels from the Basin.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**475,889**	494,952	506,571	**460,443**	405,970
North America – Oil Sands Mining and Upgrading [(1)]	**417,089**	350,633	357,856	**417,351**	395,133
North Sea	**17,057**	21,220	30,860	**23,142**	27,919
Offshore Africa	**17,155**	17,537	18,495	**17,022**	21,371
	927,190	884,342	913,782	**917,958**	850,393
Natural gas (MMcf/d)					
North America	**1,623**	1,340	1,411	**1,450**	1,443
North Sea	**4**	5	25	**12**	24
Offshore Africa	**17**	17	19	**15**	24
	1,644	1,362	1,455	**1,477**	1,491
Total barrels of oil equivalent (BOE/d)	**1,201,198**	1,111,286	1,156,276	**1,164,136**	1,098,957
Product mix					
Light and medium crude oil and NGLs	**10%**	11%	12%	**11%**	13%
Pelican Lake heavy crude oil	**5%**	5%	5%	**5%**	5%
Primary heavy crude oil	**5%**	6%	8%	**6%**	8%
Bitumen (thermal oil)	**22%**	26%	23%	**21%**	15%
Synthetic crude oil [(1)]	**35%**	32%	31%	**36%**	36%
Natural gas	**23%**	20%	21%	**21%**	23%
Percentage of gross revenue [(1) (2)] (excluding Midstream and Refining revenue)					
Crude oil and NGLs	**90%**	93%	94%	**91%**	94%
Natural gas	**10%**	7%	6%	**9%**	6%

(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			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**433,697**	455,393	438,894	**420,906**	356,794
North America – Oil Sands Mining and Upgrading	**411,640**	347,475	340,262	**413,363**	375,048
North Sea	**17,023**	21,150	30,815	**23,086**	27,866
Offshore Africa	**16,416**	16,767	17,294	**16,306**	20,078
	878,776	840,785	827,265	**873,661**	779,786
Natural gas (MMcf/d)					
North America	**1,553**	1,298	1,351	**1,406**	1,400
North Sea	**4**	5	25	**12**	24
Offshore Africa	**16**	16	18	**14**	22
	1,573	1,319	1,394	**1,432**	1,446
Total barrels of oil equivalent (BOE/d)	**1,141,022**	1,060,629	1,059,562	**1,112,364**	1,020,749

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

Crude oil and NGLs production before royalties for the year ended December 31, 2020 averaged 917,958 bbl/d, an increase of 8% from 850,393 bbl/d for the year ended December 31, 2019. Crude oil and NGLs production for the fourth quarter of 2020 of 927,190 bbl/d was comparable with 913,782 bbl/d for the fourth quarter of 2019, and increased 5% from 884,342 bbl/d for the third quarter of 2020. The increase in crude oil and NGLs production for the year ended December 31, 2020 from 2019 primarily reflected the acquisition of Jackfish assets, increased thermal oil production at Kirby North, and high utilization rates and operational enhancements in the Oil Sands Mining and Upgrading segment. The increase in crude oil and NGLs production for the fourth quarter of 2020 from the comparable periods primarily reflected the completion of planned maintenance and turnaround activities at AOSP and Horizon, combined with continued high utilization rates and operational enhancements in the Oil Sands Mining and Upgrading segment. Production for all periods reflected the impact of the Company's curtailment optimization strategy as a result of mandatory Government of Alberta curtailment, which was suspended effective December 1, 2020.

Natural gas production before royalties for the year ended December 31, 2020 of 1,477 MMcf/d was comparable with 1,491 MMcf/d for the year ended December 31, 2019. Natural gas production for the fourth quarter of 2020 of 1,644 MMcf/d increased 13% from 1,455 MMcf/d for the fourth quarter of 2019, and increased 21% from 1,362 MMcf/d for the third quarter of 2020. The increase in natural gas production for the fourth quarter of 2020 from the comparable periods primarily reflected added volumes from opportunities identified by the Company in the first half of 2020 and production volumes from the acquisition of Painted Pony on October 6, 2020, partially offset by natural field declines.

Due to the uncertainty regarding COVID-19, the Company withdrew its 2020 corporate production guidance, however, annual 2020 crude oil and NGLs and natural gas production before royalties was within the previously issued corporate guidance range. 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 information. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the year ended December 31, 2020 averaged 460,443 bbl/d, an increase of 13% from 405,970 bbl/d for the year ended December 31, 2019. North America crude oil and NGLs production for the fourth quarter of 2020 of 475,889 bbl/d decreased 6% from 506,571 bbl/d for the fourth quarter of 2019, and decreased 4% from 494,952 bbl/d for the third quarter of 2020. The increase in crude oil and NGLs production for the year ended December 31, 2020 from 2019 primarily reflected the acquisition of Jackfish assets, increased thermal oil production at Kirby North, and the optimization of steam cycles at Primrose. The decrease in crude oil and NGLs production for the fourth quarter of 2020 from the comparable periods primarily reflected the Company's curtailment optimization strategy, including higher production in the North America – Exploration and Production segment in the fourth quarter of 2019 as the Company completed planned and unplanned maintenance in the Oil Sands Mining and Upgrading segment. Production for all periods reflected the impact of mandatory Government of Alberta curtailment, which was suspended effective December 1, 2020.

Thermal oil production before royalties for the fourth quarter of 2020 averaged 266,179 bbl/d, an increase of 3% from 259,387 bbl/d for the fourth quarter of 2019, and a decrease of 8% from 287,978 bbl/d for the third quarter of 2020. The increase in thermal oil production from the fourth quarter of 2019 primarily reflected the impact of increased production at Kirby North and Jackfish. Thermal oil production decreased from the third quarter of 2020 primarily as a result of the Company's curtailment optimization strategy.

Pelican Lake heavy crude oil production before royalties averaged 56,036 bbl/d for the fourth quarter of 2020, a decrease of 5% from 59,013 bbl/d for the fourth quarter of 2019, and was comparable with 56,392 bbl/d for the third quarter of 2020, demonstrating Pelican Lake's long-life low decline production.

Natural gas production before royalties for the year ended December 31, 2020 of 1,450 MMcf/d increased slightly from 1,443 MMcf/d for the year ended December 31, 2019. Natural gas production for the fourth quarter of 2020 averaged 1,623 MMcf/d, an increase of 15% from 1,411 MMcf/d for the fourth quarter of 2019, and an increase of 21% from 1,340 MMcf/d for the third quarter of 2020. The increase in natural gas production for the three months and year ended December 31, 2020 from the comparable periods primarily reflected added volumes from opportunities identified by the Company in the first half of 2020 and the acquisition of Painted Pony on October 6, 2020, partially offset by the impact of natural field declines.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the year ended December 31, 2020 of 417,351 bbl/d increased 6% from 395,133 bbl/d for the year ended December 31, 2019. SCO production for the fourth quarter of 2020 increased 17% to average 417,089 bbl/d from 357,856 bbl/d for the fourth quarter of 2019 and increased 19% from 350,633 bbl/d for the third quarter of 2020. The increase in SCO production for the year ended December 31, 2020 from 2019 primarily reflected high utilization rates and operational enhancements, partially offset by the impact of planned maintenance activities. The increase in SCO production for the fourth quarter of 2020 from the comparable periods primarily reflected continued high utilization rates following the successful completion of planned maintenance activities at Horizon, together with expanded front-end capacity at AOSP. The fourth quarter of 2020 also reflected the impact of the Company's curtailment optimization strategy, including the suspension of mandatory Government of Alberta curtailment effective December 1, 2020.

North Sea

North Sea crude oil production before royalties for the year ended December 31, 2020 of 23,142 bbl/d decreased 17% from 27,919 bbl/d for the year ended December 31, 2019. North Sea crude oil production for the fourth quarter of 2020 decreased 45% to 17,057 bbl/d from 30,860 bbl/d for the fourth quarter of 2019 and decreased 20% from 21,220 bbl/d for the third quarter of 2020. The decrease in production for the year ended December 31, 2020 from 2019 primarily reflected the permanent cessation of production at the Banff and Kyle fields on June 1, 2020 and natural field declines. The decrease in production for the fourth quarter of 2020 from the fourth quarter of 2019 primarily reflected the permanent cessation of production at the Banff and Kyle fields on June 1, 2020, planned turnaround activities, and natural field declines. The decrease in production from the third quarter of 2020 primarily reflected planned turnaround activities during the fourth quarter of 2020 and natural field declines.

Offshore Africa

Offshore Africa crude oil production before royalties for the year ended December 31, 2020 decreased 20% to 17,022 bbl/d from 21,371 bbl/d for the year ended December 31, 2019. Offshore Africa crude oil production for the fourth quarter of 2020 of 17,155 bbl/d decreased 7% from 18,495 bbl/d for the fourth quarter of 2019 and was comparable with 17,537 bbl/d for the third quarter of 2020. The decrease in production for the three months and year ended December 31, 2020 from the comparable periods in 2019 primarily reflected natural field declines.

International Crude Oil Inventory Volumes

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

(bbl)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019
North Sea	**450,889**	730,801	344,726
Offshore Africa	**521,244**	779,347	519,504
	972,133	1,510,148	864,230

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 40.56**	$ 40.14	$ 49.60	**$ 31.90**	$ 55.08
Transportation (3)	**3.81**	3.60	3.53	**3.85**	3.48
Realized sales price, net of transportation	**36.75**	36.54	46.07	**28.05**	51.60
Royalties	**3.34**	3.03	6.03	**2.59**	6.08
Production expense	**12.47**	11.03	12.46	**12.42**	13.81
Netback	**$ 20.94**	$ 22.48	$ 27.58	**$ 13.04**	$ 31.71
Natural gas ($/Mcf) (1)					
Sales price	**$ 2.94**	$ 2.31	$ 2.64	**$ 2.40**	$ 2.34
Transportation	**0.42**	0.42	0.43	**0.43**	0.42
Realized sales price, net of transportation	**2.52**	1.89	2.21	**1.97**	1.92
Royalties	**0.13**	0.07	0.11	**0.08**	0.08
Production expense	**1.10**	1.18	1.17	**1.18**	1.22
Netback	**$ 1.29**	$ 0.64	$ 0.93	**$ 0.71**	$ 0.62
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 32.61**	$ 32.28	$ 39.20	**$ 26.15**	$ 40.50
Transportation (3)	**3.37**	3.28	3.24	**3.44**	3.14
Realized sales price, net of transportation	**29.24**	29.00	35.96	**22.71**	37.36
Royalties	**2.44**	2.25	4.37	**1.89**	4.09
Production expense	**10.43**	9.84	10.79	**10.67**	11.49
Netback	**$ 16.37**	$ 16.91	$ 20.80	**$ 10.15**	$ 21.78

(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			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 39.54**	$ 38.86	$ 46.06	**$ 30.31**	$ 51.43
North Sea	**$ 56.18**	$ 57.84	$ 87.76	**$ 50.09**	$ 86.76
Offshore Africa	**$ 49.05**	$ 55.11	$ 70.73	**$ 50.95**	$ 83.68
Average	**$ 40.56**	$ 40.14	$ 49.60	**$ 31.90**	$ 55.08
Natural gas ($/Mcf) (1)					
North America	**$ 2.91**	$ 2.25	$ 2.52	**$ 2.34**	$ 2.18
North Sea	**$ 1.41**	$ 3.44	$ 5.10	**$ 2.74**	$ 6.52
Offshore Africa	**$ 6.64**	$ 7.32	$ 8.58	**$ 7.77**	$ 7.41
Average	**$ 2.94**	$ 2.31	$ 2.64	**$ 2.40**	$ 2.34
Average ($/BOE) (1) (2)	**$ 32.61**	$ 32.28	$ 39.20	**$ 26.15**	$ 40.50

(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 decreased 41% to average $30.31 per bbl for the year ended December 31, 2020 from $51.43 per bbl for the year ended December 31, 2019. North America realized crude oil prices averaged $39.54 per bbl for the fourth quarter of 2020, a decrease of 14% compared with $46.06 per bbl for the fourth quarter of 2019, and comparable with $38.86 per bbl for the third quarter of 2020. The decrease in realized crude oil prices for the three months and year ended December 31, 2020 from the comparable periods in 2019 was primarily due to lower WTI benchmark pricing due to decreased demand for refined products as a result of COVID-19, partially offset by the narrowing of the WCS Heavy Differential. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2020 contributed approximately 138,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 7% to average $2.34 per Mcf for the year ended December 31, 2020 from $2.18 per Mcf for the year ended December 31, 2019. North America realized natural gas prices increased 15% to average $2.91 per Mcf for the fourth quarter of 2020 from $2.52 per Mcf for the fourth quarter of 2019, and increased 29% from $2.25 per Mcf for the third quarter of 2020. The increase in realized natural gas prices for the three months and year ended December 31, 2020 from the comparable periods primarily reflected lower production levels from the Basin.

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

	Three Months Ended		
(Quarterly average)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 38.03**	$ 36.48	$ 47.32
Pelican Lake heavy crude oil ($/bbl)	**$ 43.21**	$ 42.97	$ 51.66
Primary heavy crude oil ($/bbl)	**$ 42.01**	$ 42.63	$ 49.72
Bitumen (thermal oil) ($/bbl)	**$ 38.67**	$ 37.78	$ 42.93
Natural gas ($/Mcf)	**$ 2.91**	$ 2.25	$ 2.52

(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 decreased 42% to average $50.09 per bbl for the year ended December 31, 2020 from $86.76 per bbl for the year ended December 31, 2019. North Sea realized crude oil prices decreased 36% to average $56.18 per bbl for the fourth quarter of 2020 from $87.76 per bbl for the fourth quarter of 2019 and decreased 3% from $57.84 per bbl for the third 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 decrease in realized crude oil prices for the three months and year ended December 31, 2020 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 decreased 39% to average $50.95 per bbl for the year ended December 31, 2020 from $83.68 per bbl for the year ended December 31, 2019. Offshore Africa realized crude oil prices decreased 31% to average $49.05 per bbl for the fourth quarter of 2020 from $70.73 per bbl for the fourth quarter of 2019 and decreased 11% from $55.11 per bbl for the third 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 decrease in realized crude oil prices for the three months and year ended December 31, 2020 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 3.52**	$ 3.15	$ 6.52	**$ 2.72**	$ 6.56
North Sea	**$ 0.11**	$ 0.19	$ 0.13	**$ 0.12**	$ 0.16
Offshore Africa	**$ 2.11**	$ 2.42	$ 4.60	**$ 2.17**	$ 4.74
Average	**$ 3.34**	$ 3.03	$ 6.03	**$ 2.59**	$ 6.08
Natural gas ($/Mcf) (1)					
North America	**$ 0.13**	$ 0.07	$ 0.11	**$ 0.07**	$ 0.07
Offshore Africa	**$ 0.30**	$ 0.34	$ 0.39	**$ 0.37**	$ 0.63
Average	**$ 0.13**	$ 0.07	$ 0.11	**$ 0.08**	$ 0.08
Average ($/BOE) (1)	**$ 2.44**	$ 2.25	$ 4.37	**$ 1.89**	$ 4.09

(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 three months and year ended December 31, 2020 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 9% of product sales for the year ended December 31, 2020 compared with 13% of product sales for the year ended December 31, 2019. Crude oil and NGLs royalty rates averaged approximately 9% of product sales for the fourth quarter of 2020 compared with 14% for the fourth quarter of 2019 and 8% for the third quarter of 2020. The decrease in royalty rates for the three months and year ended December 31, 2020 from the comparable periods in 2019 primarily reflected lower realized crude oil prices. The increase in the royalty rate for the fourth quarter of 2020 from the third quarter of 2020 primarily reflected higher realized crude oil prices in the fourth quarter of 2020.

Natural gas royalty rates averaged approximately 3% of product sales for the year ended December 31, 2020 compared with 3% of product sales for the year ended December 31, 2019. Natural gas royalty rates averaged approximately 4% of product sales for the fourth quarter of 2020 compared with 4% for the fourth quarter of 2019 and 3% for the third quarter of 2020. The increase in royalty rates for the fourth quarter of 2020 from the third quarter of 2020 primarily reflected higher realized natural gas prices.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 4% for the year ended December 31, 2020, compared with 6% of product sales for the year ended December 31, 2019. Royalty rates as a percentage of product sales averaged approximately 4% for the fourth quarter of 2020 compared with 6% of product sales for the fourth quarter of 2019 and 4% for the third 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			Year Ended	
	Dec 31 2020	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 10.81**	$ 9.80	$ 10.74	**$ 11.21**	$ 12.41
North Sea	**$ 52.42**	$ 42.10	$ 33.67	**$ 36.51**	$ 36.39
Offshore Africa	**$ 11.74**	$ 16.41	$ 16.75	**$ 13.29**	$ 11.21
Average	**$ 12.47**	$ 11.03	$ 12.46	**$ 12.42**	$ 13.81
Natural gas ($/Mcf) [(1)]					
North America	**$ 1.07**	$ 1.14	$ 1.11	**$ 1.14**	$ 1.16
North Sea	**$ 5.29**	$ 5.38	$ 3.25	**$ 3.72**	$ 3.40
Offshore Africa	**$ 3.07**	$ 3.03	$ 3.19	**$ 3.58**	$ 2.60
Average	**$ 1.10**	$ 1.18	$ 1.17	**$ 1.18**	$ 1.22
Average ($/BOE) [(1)]	**$ 10.43**	$ 9.84	$ 10.79	**$ 10.67**	$ 11.49

(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 year ended December 31, 2020 averaged $11.21 per bbl, a decrease of 10% from $12.41 per bbl for the year ended December 31, 2019. North America crude oil and NGLs production expense for the fourth quarter of 2020 of $10.81 per bbl was comparable with $10.74 per bbl for the fourth quarter of 2019 and increased 10% from $9.80 per bbl for the third quarter of 2020. The decrease in crude oil and NGLs production expense per bbl for the year ended December 31, 2020 from 2019 primarily reflected the impact of increased thermal oil volumes, together with operating cost synergies at Jackfish. The increase in crude oil and NGLs production expense per bbl for the fourth quarter of 2020 from the third quarter of 2020 primarily reflected lower volumes as a result of the Company's curtailment optimization strategy, along with the impact of higher natural gas costs.

North America natural gas production expense for the year ended December 31, 2020 averaged $1.14 per Mcf, comparable with $1.16 per Mcf for the year ended December 31, 2019. North America natural gas production expense for the fourth quarter of 2020 of $1.07 per Mcf decreased 4% from $1.11 per Mcf for the fourth quarter of 2019 and decreased 6% from $1.14 per Mcf for the third quarter of 2020. The decrease in natural gas production expense per Mcf for the three months and year ended December 31, 2020 from the comparable periods primarily reflected the Company's strategy to own and control its infrastructure and its continued focus on cost control.

North Sea

North Sea crude oil production expense for the year ended December 31, 2020 averaged $36.51 per bbl, comparable with $36.39 per bbl for the year ended December 31, 2019. North Sea crude oil production expense for the fourth quarter of 2020 of $52.42 per bbl increased 56% from $33.67 per bbl for the fourth quarter of 2019 and increased 25% from $42.10 per bbl for the third quarter of 2020. The increase in crude oil production expense per bbl for the fourth quarter of 2020 from the comparable periods was primarily due to lower volumes, as a result of maintenance activities in the fourth quarter of 2020, on a relatively fixed cost base. The increase from the fourth quarter of 2019 also reflected fluctuations in the Canadian dollar.

Offshore Africa

Offshore Africa crude oil production expense for the year ended December 31, 2020 averaged $13.29 per bbl, an increase of 19% from $11.21 per bbl for the year ended December 31, 2019. Offshore Africa crude oil production expense for the fourth quarter of 2020 of $11.74 per bbl decreased 30% from $16.75 per bbl for the fourth quarter of 2019 and decreased 28% from $16.41 per bbl for the third quarter of 2020. The increase in crude oil production expense per bbl for the year ended December 31, 2020 from 2019 was primarily due to lower volumes on a relatively fixed cost base. The decrease in crude oil production expense per bbl for the fourth quarter of 2020 from the comparable periods primarily reflected the timing of liftings from various fields that have different cost structures. Offshore Africa production expense also reflected fluctuations in the Canadian dollar.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Expense	**$ 1,132**	$ 1,046	$ 1,083	**$ 4,247**	$ 3,876
$/BOE (1)	**$ 15.55**	$ 15.01	$ 14.98	**$ 15.45**	$ 15.22

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

Depletion, depreciation and amortization expense for the year ended December 31, 2020 of $15.45 per BOE was comparable with $15.22 per BOE for the year ended December 31, 2019. Depletion, depreciation and amortization expense for the fourth quarter of 2020 of $15.55 per BOE increased 4% from $14.98 per BOE for the fourth quarter of 2019 and increased 4% from $15.01 per BOE for the third quarter of 2020. Fluctuations in depletion, depreciation and amortization expense from the comparable periods primarily reflected changes in product mix, fluctuating sales volumes from underlying operations, together with the impact of the acquisition of Painted Pony in the fourth quarter of 2020.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Expense	**$ 33**	$ 32	$ 36	**$ 133**	$ 129
$/BOE (1)	**$ 0.45**	$ 0.47	$ 0.49	**$ 0.48**	$ 0.51

(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 year ended December 31, 2020 of $0.48 per BOE decreased 6% from $0.51 per BOE for the year ended December 31, 2019. Asset retirement obligation accretion expense for the fourth quarter of 2020 of $0.45 per BOE decreased 8% from $0.49 per BOE for the fourth quarter of 2019 and decreased 4% from $0.47 per BOE for the third 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. Production in the fourth quarter of 2020 averaged 417,089 bbl/d, reflecting the ramp-up of production after the completion of expansion activities at AOSP and the successful planned maintenance activities at Horizon, as well as the impact of the Company's curtailment optimization strategy, including the suspension of mandatory Government of Alberta curtailment effective December 1, 2020.

The Company incurred production costs, excluding natural gas costs, of $2,968 million for the year ended December 31, 2020, a $183 million, or 6% decrease from the year ended December 31, 2019.

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

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
SCO realized sales price (2)	**$ 48.56**	$ 48.92	$ 68.67	**$ 43.98**	$ 70.18
Bitumen value for royalty purposes (3)	**$ 34.70**	$ 36.26	$ 44.88	**$ 25.82**	$ 50.79
Bitumen royalties (4)	**$ 0.59**	$ 0.46	$ 3.47	**$ 0.51**	$ 3.31
Transportation	**$ 1.36**	$ 1.30	$ 1.33	**$ 1.23**	$ 1.29

(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 $43.98 per bbl for the year ended December 31, 2020, a decrease of 37% from $70.18 per bbl for the year ended December 31, 2019. For the fourth quarter of 2020, the realized sales price decreased 29% to $48.56 per bbl from $68.67 per bbl for the fourth quarter of 2019 and was comparable with $48.92 per bbl for the third quarter of 2020. The decrease in the realized SCO sales price for the three months and year ended December 31, 2020 from the comparable periods in 2019 primarily reflected decreases in WTI benchmark pricing.

Transportation expense averaged $1.23 per bbl for the year ended December 31, 2020, comparable with $1.29 per bbl for the year ended December 31, 2019. For the fourth quarter of 2020, transportation expense of $1.36 per bbl, was comparable with $1.33 per bbl for the fourth quarter of 2019 and comparable with $1.30 per bbl for the third quarter of 2020.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 18 to the Company’s unaudited interim consolidated financial statements.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Production costs, excluding natural gas costs	**$ 736**	$ 760	$ 814	**$ 2,968**	$ 3,151
Natural gas costs	**51**	28	42	**146**	125
Production costs	**$ 787**	$ 788	$ 856	**$ 3,114**	$ 3,276

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Production costs, excluding natural gas costs	**$ 18.89**	$ 22.96	$ 23.86	**$ 19.50**	$ 21.70
Natural gas costs	**1.31**	0.85	1.23	**0.96**	0.86
Production costs	**$ 20.20**	$ 23.81	$ 25.09	**$ 20.46**	$ 22.56
Sales (bbl/d)	**423,438**	359,479	370,468	**415,741**	397,735

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

Production costs for the year ended December 31, 2020 decreased by $2.10 per bbl or 9% to $20.46 per bbl from $22.56 per bbl for the year ended December 31, 2019. Production costs for the fourth quarter of 2020 averaged $20.20 per bbl, a decrease of $4.89 per bbl or 19% from $25.09 per bbl for the fourth quarter of 2019 and a decrease of $3.61 per bbl or 15% from $23.81 per bbl for the third quarter of 2020.

The decrease in production costs per bbl for the three months and year ended December 31, 2020 from the comparable periods primarily reflected high reliability and operational enhancements at both Horizon and AOSP. 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			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Expense	**$ 479**	$ 414	$ 464	**$ 1,784**	$ 1,656
$/bbl (1)	**$ 12.31**	$ 12.51	$ 13.61	**$ 11.73**	$ 11.41

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

Depletion, depreciation and amortization expense for the year ended December 31, 2020 of $11.73 per bbl was comparable with $11.41 per bbl for the year ended December 31, 2019. Depletion, depreciation and amortization expense for the fourth quarter of 2020 of $12.31 per bbl decreased 10% from $13.61 per bbl for the fourth quarter of 2019, and was comparable with $12.51 per bbl for the third 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			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Expense	**$ 18**	$ 19	$ 14	**$ 72**	$ 61
$/bbl (1)	**$ 0.47**	$ 0.55	$ 0.44	**$ 0.47**	$ 0.42

(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 year ended December 31, 2020 of $0.47 per bbl increased 12% from $0.42 per bbl for the year ended December 31, 2019. Asset retirement obligation accretion expense of $0.47 per bbl for the fourth quarter of 2020 increased 7% from $0.44 per bbl for the fourth quarter of 2019 and decreased 15% from $0.55 per bbl for the third quarter of 2020. Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

MIDSTREAM AND REFINING

($ millions)	Three Months Ended **Dec 31 2020**	Sep 30 2020	Dec 31 2019	Year Ended **Dec 31 2020**	Dec 31 2019
Product sales					
Crude oil and NGLs, midstream activities	**$ 21**	$ 21	$ 26	**$ 83**	$ 88
NWRP, refined product sales	**99**	78	—	**202**	—
Segmented revenue	**120**	99	26	**285**	88
Less:					
Production expenses					
NWRP, refining toll	**72**	70	—	**166**	—
Midstream	**3**	4	5	**18**	20
NWRP, transportation and feedstock costs	**83**	76	—	**181**	—
Depreciation	**4**	4	3	**15**	14
Equity loss from investment in NWRP	**—**	—	73	**—**	287
Segmented loss before taxes	**$ (42)**	$ (55)	$ (55)	**$ (95)**	$ (233)

The Company's Midstream and Refining assets consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose and the Company's 50% 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 three months ended December 31, 2020, production of ultra-low sulphur diesel and other refined products averaged 65,670 BOE/d (16,417 BOE/d to the Company).

The Company's unrecognized share of the equity (income) loss from NWRP for the three months ended December 31, 2020 was a recovery of unrecognized losses of $6 million (year ended December 31, 2020 – unrecognized equity loss of $94 million; December 31, 2019 – recognized equity loss of $287 million and unrecognized equity loss of $59 million). As at December 31, 2020, the cumulative unrecognized share of losses from NWRP was $153 million (December 31, 2019 – $59 million).

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended **Dec 31 2020**	Sep 30 2020	Dec 31 2019	Year Ended **Dec 31 2020**	Dec 31 2019
Expense	**$ 107**	$ 88	$ 95	**$ 391**	$ 344
$/BOE (1)	**$ 0.96**	$ 0.85	$ 0.90	**$ 0.92**	$ 0.86

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

Administration expense for the year ended December 31, 2020 of $0.92 per BOE increased 7% from $0.86 per BOE for the year ended December 31, 2019. Administration expense for the fourth quarter of 2020 of $0.96 per BOE increased 7% from $0.90 per BOE for the fourth quarter of 2019 and increased 13% from $0.85 per BOE for the third quarter of 2020. Administration expense per BOE increased for the year ended December 31, 2020 from 2019 primarily due to lower overhead recoveries and increased corporate and personnel costs. Administration expense per BOE increased for the fourth quarter of 2020 from the fourth quarter of 2019 primarily due to lower overhead recoveries and increased corporate costs, partially offset by the impact of lower personnel costs. The increase in administration expense per BOE for the fourth quarter of 2020 from the third quarter of 2020 was primarily due to higher personnel and corporate costs, partially offset by the impact of higher overhead recoveries.

SHARE-BASED COMPENSATION

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Expense (recovery)	**$ 123**	$ (5)	$ 161	**$ (82)**	$ 223

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

The Company recognized an $82 million share-based compensation recovery for the year ended December 31, 2020, 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 recovery for the year ended December 31, 2020 was an expense of $21 million related to PSUs granted to certain executive employees (December 31, 2019 – $49 million expense). For the year ended December 31, 2020, the Company charged $5 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (December 31, 2019 – $5 million charged).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts and interest rates)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Expense, gross	**$ 180**	$ 180	$ 225	**$ 780**	$ 889
Less: capitalized interest	**3**	6	8	**24**	53
Expense, net	**$ 177**	$ 174	$ 217	**$ 756**	$ 836
$/BOE (1)	**$ 1.59**	$ 1.69	$ 2.04	**$ 1.77**	$ 2.09
Average effective interest rate	**3.3%**	3.4%	3.9%	**3.5%**	4.0%

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

Gross interest and other financing expense for the three months and year ended December 31, 2020 decreased from the comparable periods in 2019 primarily due to lower interest rates. Capitalized interest of $24 million for the year ended December 31, 2020 was related to residual project activities at Horizon.

Net interest and other financing expense per BOE for the year ended December 31, 2020 decreased 15% to $1.77 per BOE from $2.09 per BOE for the year ended December 31, 2019. Net interest and other financing expense per BOE for the fourth quarter of 2020 decreased 22% to $1.59 per BOE from $2.04 per BOE for the fourth quarter of 2019 and decreased 6% from $1.69 per BOE for the third quarter of 2020. The decrease in net interest and other financing expense per BOE for the three months and year ended December 31, 2020 from the comparable periods was primarily due to lower average interest rates.

The Company's average effective interest rate for the fourth quarter of 2020 decreased from the comparable periods primarily due to the impact of lower benchmark interest rates on the Company's outstanding bank credit facilities and US commercial paper program.

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			Year Ended	
($ millions)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Foreign currency contracts	**$ 25**	$ 20	$ 5	**$ 16**	$ 13
Natural gas financial instruments	**(2)**	5	6	**16**	(1)
Crude oil and NGLs financial instruments	**—**	—	—	**—**	52
Net realized loss	**23**	25	11	**32**	64
Foreign currency contracts	**6**	—	10	**(3)**	15
Natural gas financial instruments	**(27)**	(2)	7	**(36)**	15
Crude oil and NGLs financial instruments	**—**	—	—	**—**	(17)
Net unrealized (gain) loss	**(21)**	(2)	17	**(39)**	13
Net loss (gain)	**$ 2**	$ 23	$ 28	**$ (7)**	$ 77

During the year ended December 31, 2020, net realized risk management losses were related to the settlement of foreign currency contracts and natural gas financial instruments. The Company recorded a net unrealized gain of $39 million ($31 million after-tax) on its risk management activities for the year ended December 31, 2020, including the impact of natural gas financial instruments from the Painted Pony acquisition in the fourth quarter of 2020. It also included an unrealized gain of $21 million ($16 million after-tax) for the fourth quarter of 2020 (September 30, 2020 – unrealized gain of $2 million, $1 million after-tax; December 31, 2019 – unrealized loss of $17 million, $16 million after-tax).

Further details related to outstanding derivative financial instruments at December 31, 2020 are disclosed in note 16 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Net realized loss (gain)	**$ 21**	$ 16	$ (4)	**$ (159)**	$ (22)
Net unrealized gain	**(534)**	(270)	(225)	**(116)**	(548)
Net gain (1)	**$ (513)**	$ (254)	$ (229)	**$ (275)**	$ (570)

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

The net realized foreign exchange gain for the year ended December 31, 2020 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the settlement of the US$500 million cross currency swaps during the first quarter of 2020. The net unrealized foreign exchange gain for the year ended December 31, 2020 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized gain 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 in the first quarter of 2020 (three months ended December 31, 2020 – unrealized loss of $32 million, September 30, 2020 – unrealized loss of $16 million, December 31, 2019 – unrealized loss of $29 million; year ended December 31, 2020 – unrealized loss of $150 million, December 31, 2019 – unrealized loss of $71 million). The US/Canadian dollar exchange rate at December 31, 2020 was US$0.7840 (September 30, 2020 – US$0.7505, December 31, 2019 – US$0.7713).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Dec 31 2020	Three Months Ended Sep 30 2020	Three Months Ended Dec 31 2019	Year Ended Dec 31 2020	Year Ended Dec 31 2019
North America [1]	**$ 42**	$ (59)	$ (20)	**$ (245)**	$ 354
North Sea	**—**	(14)	40	**(4)**	112
Offshore Africa	**5**	6	7	**17**	44
PRT [2] – North Sea	**(14)**	(17)	—	**(31)**	(89)
Other taxes	**2**	2	4	**6**	13
Current income tax expense (recovery)	**35**	(82)	31	**(257)**	434
Deferred corporate income tax (recovery) expense	**(25)**	91	194	**(181)**	(895)
Deferred PRT [2] – North Sea	**—**	—	—	**—**	1
Deferred income tax (recovery) expense	**(25)**	91	194	**(181)**	(894)
Income tax expense (recovery)	**10**	9	225	**(438)**	(460)
Income tax rate and other legislative changes	**—**	—	—	**—**	1,618
	$ 10	$ 9	$ 225	**$ (438)**	$ 1,158
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**24%**	15%	26%	**34%**	25%

(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 three months and year ended December 31, 2020 and the comparable periods included the impact of non-taxable items in North America and 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 year ended December 31, 2020 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.

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

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

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Dec 31 2020	Sep 30 2020	Dec 31 2019	Year Ended Dec 31 2020	Dec 31 2019
Exploration and Evaluation					
Net property (dispositions) acquisitions [2]	**$ (1)**	$ (12)	$ —	**$ (31)**	$ 90
Net expenditures	**9**	1	—	**36**	74
Total Exploration and Evaluation	**8**	(11)	—	**5**	164
Property, Plant and Equipment					
Net property acquisitions (dispositions) [2] [3]	**522**	(1)	20	**536**	3,208
Well drilling, completion and equipping	**115**	80	169	**429**	775
Production and related facilities	**131**	157	238	**580**	1,028
Capitalized interest and other	**20**	14	15	**60**	81
Total Property, Plant and Equipment	**788**	250	442	**1,605**	5,092
Total Exploration and Production	**796**	239	442	**1,610**	5,256
Oil Sands Mining and Upgrading					
Project costs	**86**	67	121	**258**	436
Sustaining capital	**212**	254	334	**839**	933
Turnaround costs	**22**	131	57	**196**	118
Capitalized interest and other	**4**	8	9	**30**	38
Total Oil Sands Mining and Upgrading	**324**	460	521	**1,323**	1,525
Midstream and Refining	**1**	1	1	**5**	10
Abandonments [4]	**52**	68	84	**249**	296
Head office	**3**	3	8	**19**	34
Total net capital expenditures	**$ 1,176**	$ 771	$ 1,056	**$ 3,206**	$ 7,121
By segment					
North America [2] [3]	**$ 729**	$ 170	$ 330	**$ 1,389**	$ 4,831
North Sea	**34**	45	63	**122**	196
Offshore Africa	**33**	24	49	**99**	229
Oil Sands Mining and Upgrading	**324**	460	521	**1,323**	1,525
Midstream and Refining	**1**	1	1	**5**	10
Abandonments [4]	**52**	68	84	**249**	296
Head office	**3**	3	8	**19**	34
Total	**$ 1,176**	$ 771	$ 1,056	**$ 3,206**	$ 7,121

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

(2) Includes cash consideration paid of $91 million for exploration and evaluation assets and $3,126 million for property, plant and equipment acquired from Devon in the second quarter of 2019.

(3) 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.

(4) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Cash flows used in investing activities	***$ 624***	*$ 643*	*$ 854*	***$ 2,819***	*$ 7,255*
Net change in non-cash working capital [1]	***(21)***	*60*	*118*	***(383)***	*(430)*
Repayment of NWRP subordinated debt advances [2]	***124***	*—*	*—*	***124***	*—*
Abandonment expenditures [3]	***52***	*68*	*84*	***249***	*296*
Other [4]	***397***	*—*	*—*	***397***	*—*
Net capital expenditures	***$ 1,176***	*$ 771*	*$ 1,056*	***$ 3,206***	*$ 7,121*

(1) Includes net working capital and other long-term assets of $195 million related to the acquisition of assets from Devon in the second quarter of 2019.

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

(3) 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.

(4) 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 development 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.

On October 6, 2020, the Company completed the acquisition of all of the issued and outstanding common shares of Painted Pony for net cash consideration of approximately $111 million. At closing, the acquisition also included the assumption of long-term debt of approximately $397 million.

Capital expenditures totaled $1,176 million for the fourth quarter of 2020 and $3,206 million for the year ended December 31, 2020. Capital expenditures excluding the impact of the acquisition of Painted Pony in the fourth quarter of 2020 were $2,698 million for the year ended December 31, 2020, reflecting the Company's flexible and disciplined approach.

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			Year Ended	
(number of net wells)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019	**Dec 31 2020**	Dec 31 2019
Net successful natural gas wells	**9**	9	4	**30**	19
Net successful crude oil wells [2]	**5**	—	12	**42**	86
Dry wells	**—**	—	—	**—**	3
Stratigraphic test / service wells	**—**	1	89	**372**	447
Total	**14**	10	105	**444**	555
Success rate (excluding stratigraphic test / service wells)	**100%**	100%	100%	**100%**	97%

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

(2) Includes bitumen wells.

North America

During the fourth quarter of 2020, the Company targeted 9 net natural gas wells and 5 net light crude oil wells.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Dec 31 2020**	Sep 30 2020	Dec 31 2019
Working capital (1)	**$ 626**	$ 707	$ 241
Long-term debt (2) (3)	**$ 21,453**	$ 21,876	$ 20,982
Less: cash and cash equivalents	**184**	175	139
Long-term debt, net	**$ 21,269**	$ 21,701	$ 20,843
Share capital	**$ 9,606**	$ 9,522	$ 9,533
Retained earnings	**22,766**	22,520	25,424
Accumulated other comprehensive income	**8**	124	34
Shareholders' equity	**$ 32,380**	$ 32,166	$ 34,991
Debt to book capitalization (3) (4)	**39.6%**	40.3%	37.3%
Debt to market capitalization (3) (5)	**37.0%**	46.3%	29.5%
After-tax return on average common shareholders' equity (6)	**(1.3)%**	(1.8)%	16.1%
After-tax return on average capital employed (3) (7)	**0.2 %**	0.0%	10.9%

(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 December 31, 2020, 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, 2019. 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 that its internally generated cash flows from operating activities supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long-term and support its growth strategy.

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

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and

- Reviewing the Company's borrowing capacity:
  - During the fourth quarter of 2020, the Company issued $500 million of 1.45% notes due November 2023 and $300 million of 2.50% notes due January 2028. After issuing these securities, 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.
  - During the second quarter of 2020, the Company issued US$600 million of 2.05% notes due July 2025 and US$500 million of 2.95% notes due July 2030. After issuing these securities, 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.
  - During the third quarter of 2020, the Company repaid $1,000 million of 2.89% medium-term notes.
  - During the second quarter of 2020, the Company repaid $900 million of 2.05% medium-term notes.
  - Each of the Company's $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.
  - Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2020, the non-revolving term credit facilities were fully drawn.
  - During the second quarter of 2020, the $750 million non-revolving term credit facility, originally due February 2021, was extended to February 2022 and increased to $1,000 million. Subsequent to December 31, 2020, the facility 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 the second quarter of 2020, the Company repaid $162.5 million related to the required annual amortization, reducing the facility balance to $3,088 million. Subsequent to December 31, 2020, the Company repaid a further $362.5 million on the facility, reducing the outstanding balance to $2,725 million, and satisfying the required annual amortization of $162.5 million originally due in June 2021. The facility matures in June 2022.
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

As at December 31, 2020, the Company had undrawn revolving bank credit facilities of $4,958 million. Including cash and cash equivalents and short-term investments, the Company had approximately $5,447 million in liquidity. Additionally, the Company had in place fully drawn term credit facilities of $6,738 million. The Company also has certain other dedicated credit facilities supporting letters of credit. At December 31, 2020, the Company had $544 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

As at December 31, 2020, the Company had total US dollar denominated debt with a carrying amount of $16,746 million (US$13,129 million), before transaction costs and original issue discounts. This included $6,287 million (US$4,929 million) hedged by way of a cross currency swap (US$550 million) and foreign currency forwards (US$4,379 million). The fixed repayment amount of these hedging instruments is $6,337 million, resulting in a notional increase of the carrying amount of the Company's US dollar denominated debt by approximately $50 million to $16,796 million as at December 31, 2020.

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.

Net long-term debt was $21,269 million at December 31, 2020, resulting in a debt to book capitalization ratio of 39.6% (December 31, 2019 – 37.3%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities are greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at December 31, 2020 are discussed in note 9 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 December 31, 2020, the Company was in compliance with this covenant.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2020 are discussed in note 16 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)	$ 1,343	$ 4,887	$ 7,051	$ 8,279
Other long-term liabilities (2)	$ 345	$ 200	$ 435	$ 942
Interest and other financing expense (3)	$ 776	$ 693	$ 1,619	$ 4,452

(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, $189 million; one to less than two years, $162 million; two to less than five years, $397 million; and thereafter, $942 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2020.

Share Capital

As at December 31, 2020, there were 1,183,866,000 common shares outstanding (December 31, 2019 – 1,186,857,000 common shares) and 48,656,000 stock options outstanding. As at March 2, 2021, the Company had 1,185,574,000 common shares outstanding and 53,829,000 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. On March 4, 2020, the Board of Directors approved an increase in the quarterly dividend to $0.425 per common share (previous quarterly dividend rate of $0.375 per common share). The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On May 21, 2019, 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 59,729,706 common shares, over a 12-month period commencing May 23, 2019 and ending May 22, 2020. The Company did not renew its Normal Course Issuer Bid after its expiry in May 2020.

During the first quarter of 2020, the Company purchased 6,970,000 common shares at a weighted average price of $38.84 per common share for a total cost of $271 million. Retained earnings were reduced by $215 million, representing the excess of the purchase price of common shares over their average carrying value.

On March 3, 2021, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the Toronto Stock Exchange ("TSX") to purchase, by way of a normal course issuer bid, up to 5.0% of its issued and outstanding common shares for the purpose of repurchasing a number of common shares approximately equal to the number of options exercised throughout the year in order to eliminate dilution for shareholders. Subject to acceptance of the Notice of Intention by the TSX, the purchases would be made through the facilities of the TSX, alternative Canadian trading platforms and the New York Stock Exchange.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2020:

($ millions)		2021		2022		2023		2024		2025		Thereafter
Product transportation and processing [1] [2]	$	870	$	817	$	858	$	841	$	809	$	10,370
North West Redwater Partnership service toll [3]	$	163	$	160	$	160	$	156	$	150	$	2,694
Offshore vessels and equipment	$	64	$	9	$	—	$	—	$	—	$	—
Field equipment and power	$	28	$	21	$	21	$	21	$	21	$	246
Other	$	25	$	21	$	21	$	22	$	22	$	16

(1) Includes commitments pertaining to a 20-year product transportation agreement on the Trans Mountain Pipeline Expansion. In addition, the Company has entered into certain product transportation agreements on pipelines that have not yet received regulatory and other approvals.

(2) The acquisition of Painted Pony in the fourth quarter of 2020 included approximately $2,400 million of product transportation and processing commitments.

(3) 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 $1,169 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.

ACCOUNTING POLICIES

Government Grants

The Company receives or is eligible for government grants, including those introduced in response to the impact of COVID-19. Government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to the grant and the grant will be received. Grants that are intended to compensate for expenses incurred are classified as other income.

Changes in Accounting Policies

In October 2018, the IASB issued amendments to IFRS 3 "Definition of a Business" that narrowed and clarified the definition of a business. The amendments permit a simplified assessment of whether an acquired set of activities and assets is a group of assets rather than a business. The amendments apply to business combinations after the date of adoption. The Company prospectively adopted the amendments on January 1, 2020.

In October 2018, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" and IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors". The amendments make minor changes to the definition of the term "material" and align the definition across all IFRS standards. Materiality is used in making judgements related to the preparation of financial statements. The Company prospectively adopted the amendments on January 1, 2020.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. For the three months and year ended December 31, 2020, COVID-19 had an impact on the global economy, including the oil and gas industry. Business conditions in the fourth quarter of 2020 continued to reflect the market uncertainty associated with COVID-19, with some modest 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, 2019.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the year ended December 31, 2020 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.