2019

FINANCIAL SUMMARY

enerPLUS

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2019 FINANCIAL SUMMARY

SELECTED FINANCIAL RESULTS	Three months ended December 31, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Financial (CDN$, thousands, except ratios)				
Net Income/(Loss)	$ (429,143)	$ 249,315	$ (259,720)	$ 378,279
Adjusted Net Income[4]	34,365	102,167	243,160	344,813
Cash Flow from Operating Activities	188,492	221,619	694,240	738,784
Adjusted Funds Flow[4]	178,922	214,285	708,992	753,506
Dividends to Shareholders - Declared	6,656	7,234	27,688	29,256
Total Debt Net of Cash[4]	454,984	333,523	454,984	333,523
Capital Spending	99,389	72,058	618,910	593,876
Property and Land Acquisitions	6,126	9,474	24,406	25,840
Property Divestments	(316)	886	9,583	6,912
Net Debt to Adjusted Funds Flow Ratio[4]	0.6x	0.4x	0.6x	0.4x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss) - Basic	$ (1.93)	$ 1.03	$ (1.12)	$ 1.55
Net Income/(Loss) - Diluted	(1.93)	1.02	(1.12)	1.53
Weighted Average Number of Shares Outstanding (000's) - Basic	222,227	242,344	231,334	244,076
Weighted Average Number of Shares Outstanding (000's) - Diluted	222,227	245,242	231,334	247,261
Selected Financial Results per BOE[(1)(2)]				
Oil & Natural Gas Sales[3]	$ 41.64	$ 45.43	$ 42.65	$ 47.35
Royalties and Production Taxes	(10.93)	(11.58)	(10.88)	(11.92)
Commodity Derivative Instruments	0.07	(0.31)	0.42	(1.05)
Cash Operating Expenses	(8.05)	(6.99)	(7.88)	(7.00)
Transportation Costs	(3.82)	(3.71)	(3.93)	(3.63)
General and Administrative Expenses	(1.34)	(1.40)	(1.32)	(1.47)
Cash Share-Based Compensation	0.01	0.23	(0.02)	(0.01)
Interest, Foreign Exchange and Other Expenses	(0.89)	(0.90)	(0.72)	(0.92)
Current Income Tax Recovery	1.41	3.03	0.91	0.80
Adjusted Funds Flow[4]	$ 18.10	$ 23.80	$ 19.23	$ 22.15

SELECTED OPERATING RESULTS	Three months ended December 31, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Average Daily Production[2]				
Crude Oil (bbls/day)	54,344	49,968	49,704	45,424
Natural Gas Liquids (bbls/day)	5,502	4,483	4,929	4,486
Natural Gas (Mcf/day)	285,537	260,453	278,451	259,837
Total (BOE/day)	107,436	97,860	101,042	93,216
% Crude Oil and Natural Gas Liquids	56%	56%	54%	54%
Average Selling Price[(2)(3)]				
Crude Oil (per bbl)	$ 67.23	$ 64.18	$ 68.98	$ 74.59
Natural Gas Liquids (per bbl)	18.28	26.72	15.19	28.31
Natural Gas (per Mcf)	2.50	4.28	2.87	3.42
Net Wells Drilled	9	12	56	61

(1) Non-cash amounts have been excluded.
(2) Based on Company interest production volumes. See "Basis of Presentation" section in the following MD&A.
(3) Before transportation costs, royalties and commodity derivative instruments.
(4) These non-GAAP measures may not be directly comparable to similar measures presented by other entities. See "Non-GAAP Measures" section in the following MD&A.

Average Benchmark Pricing	Three months ended December 31, 2019	2018	Twelve months ended December 31, 2019	2018
WTI crude oil (US$/bbl)	$ 56.96	$ 58.81	$ 57.03	$ 64.77
Brent (ICE) crude oil (US$/bbl)	62.51	68.08	64.18	71.53
NYMEX natural gas – last day (US$/Mcf)	2.50	3.64	2.63	3.09
USD/CDN average exchange rate	1.32	1.32	1.33	1.30

Share Trading Summary For the twelve months ended December 31, 2019	CDN(1) – ERF (CDN$)	U.S.(2) – ERF (US$)
High	$ 12.55	$ 9.74
Low	$ 7.32	$ 5.50
Close	$ 9.25	$ 7.13

(1) TSX and other Canadian trading data combined.
(2) NYSE and other U.S. trading data combined.

2019 Dividends per Share	CDN$	US$(1)
First Quarter Total	$ 0.03	$ 0.02
Second Quarter Total	$ 0.03	$ 0.02
Third Quarter Total	$ 0.03	$ 0.02
Fourth Quarter Total	$ 0.03	$ 0.02
Total Year to Date	$ 0.12	$ 0.08

(1) CDN$ dividends converted at the relevant foreign exchange rate on the payment date.

Financial and Operational Highlights

- Total production for 2019 was 101,042 BOE/day an 8% (14% per share) increase from 2018. Crude oil and natural gas liquids production was 54,633 bbls/day in 2019 a 9% (15% per share) increase from 2018.

- Full year cash flow from operations for 2019 was $694.2 million and adjusted funds flow was $709.0 million, both 6% lower than 2018 primarily due to lower commodity prices and higher operating expenses in 2019.

- We reported a net loss of $259.7 million in 2019 compared to net income of $378.3 million in 2018. Earnings decreased from 2018 primarily due to a $451.1 million non-cash Canadian goodwill impairment and a loss on commodity derivative instruments of $66.1 million, compared to a gain of $88.2 million recorded in 2018. Excluding the goodwill impairment and certain other non-cash or non-recurring items, 2019 adjusted net income was $243.2 million, compared to $344.8 million in 2018. The reduction in adjusted net income was primarily due to lower commodity prices and higher operating expenses in 2019.

- In 2019, our Bakken crude oil price differential was US$3.61/bbl below WTI compared to US$3.78/bbl below WTI in 2018. Our Marcellus natural gas price differential was US$0.39/Mcf below NYMEX in 2019 compared to US$0.43/Mcf below NYMEX in 2018.

- Operating expenses in 2019 were $7.88/BOE compared to $7.00/BOE in 2018. The increase was largely due to additional well servicing activity and higher fluid handling and gas processing costs in North Dakota. Cash G&A expenses in 2019 were $1.32/BOE compared to $1.47/BOE in 2018. The lower cash general and administrative (“G&A”) expenses per BOE were primarily due to higher production levels in 2019 compared to 2018.

- Exploration and development capital spending totaled $618.9 million in 2019, slightly lower than our capital spending guidance of $625 million.

- We ended the year with total debt net of cash of $455.0 million and were undrawn on our US$600 million senior unsecured bank credit facility. Our net debt to adjusted funds flow ratio was 0.6x at December 31, 2019.

- In 2019, we repurchased 18.2 million common shares for total consideration of $178.8 million and paid $27.7 million in dividends. Subsequent to year end and up to February 20, 2020, the Company repurchased 0.3 million shares for total consideration of $2.5 million. Since initiating our share repurchase program in the third quarter of 2018, we have repurchased 24.5 million shares, representing approximately 10% of shares outstanding.

Reserve Highlights

- We replaced 139% of our 2019 production, adding 51.0 MMBOE (57% crude oil) of proved plus probable (“2P”) reserves (including revisions and economic factors).

- Material reserves growth was realized in North Dakota where we replaced 206% of our 2019 production, adding 34.2 MMBOE of 2P reserves (including revisions and economic factors).

- Total 2P reserves were 440.8 MMBOE at year end 2019 representing a 3% (11% per share) increase from year end 2018.

- Finding and development costs (“FDC”) were $15.97/BOE for proved developed producing (“PDP”) reserves, $11.37/BOE for proved reserves, and $13.05/BOE for 2P reserves, including future development costs (“FDC”).

- Finding, development and acquisition (“FD&A”) costs were $11.82/BOE for proved reserves and $13.63/BOE for 2P reserves, including FDC.

- 2P reserves were comprised of 50% crude oil, 5% natural gas liquids and 45% natural gas at year end 2019.

Management's Discussion and Analysis ("MD&A")

The following discussion and analysis of financial results is dated February 20, 2020 and is to be read in conjunction with the audited Consolidated Financial Statements (the "Financial Statements") of Enerplus Corporation ("Enerplus" or the "Company"), as at December 31, 2019 and 2018 and for the years ended December 31, 2019, 2018 and 2017.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information. The following MD&A also contains financial measures that do not have a standardized meaning as prescribed by accounting principles generally accepted in the United States of America ("U.S. GAAP"). See "Non-GAAP Measures" at the end of this MD&A for further information.

BASIS OF PRESENTATION

The Financial Statements and notes have been prepared in accordance with U.S. GAAP. All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Financial Statements. Certain prior period amounts have been restated to conform with current period presentation.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. The BOE and Mcfe rates are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1 or 0.167:1, as applicable, utilizing a conversion on this basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. All production volumes are presented on a Company interest basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests, unless otherwise stated. Company interest is not a term defined in Canadian National Instrument 51-101– Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and may not be comparable to information produced by other entities. All reserves information presented herein has been prepared in accordance with NI 51-101 and is presented at December 31, 2019 unless otherwise stated.

In accordance with U.S. GAAP, oil and natural gas sales are presented net of royalties in the Financial Statements. Under International Financial Reporting Standards, industry standard is to present oil and natural gas sales before deduction of royalties and as such this MD&A presents production, oil and natural gas sales, and BOE measures before deduction of royalties to remain comparable with our Canadian peers.

The following table provides a reconciliation of our production volumes:

	Year ended December 31,		
Average Daily Production Volumes	**2019**	**2018**	**2017**
Company interest production volumes			
Crude oil (bbls/day)	49,704	45,424	36,935
Natural gas liquids (bbls/day)	4,929	4,486	3,858
Natural gas (Mcf/day)	278,451	259,837	263,506
Company interest production volumes (BOE/day)	101,042	93,216	84,711
Royalty volumes			
Crude oil (bbls/day)	10,034	9,054	7,531
Natural gas liquids (bbls/day)	977	951	777
Natural gas (Mcf/day)	52,870	48,923	47,722
Royalty volumes (BOE/day)	19,823	18,159	16,262
Net production volumes			
Crude oil (bbls/day)	39,670	36,370	29,404
Natural gas liquids (bbls/day)	3,952	3,535	3,081
Natural gas (Mcf/day)	225,581	210,914	215,784
Net production volumes (BOE/day)	81,219	75,057	68,449

2019 FOURTH QUARTER OVERVIEW

Fourth quarter production averaged 107,436 BOE/day, which was consistent with our third quarter production of 107,181 BOE/day. Crude oil and natural gas liquids production averaged 59,846 bbls/day compared to the third quarter average of 60,121 bbls/day and was at the high end of our fourth quarter liquids production guidance range of 58,000 – 60,000 bbls/day. Our fourth quarter capital spending of $99.4 million was largely focused on drilling in North Dakota in preparation for the 2020 capital program.

We reported a net loss of $429.1 million in the fourth quarter compared to net income of $65.2 million in the third quarter. The decrease was primarily the result of a $451.1 million non-cash goodwill impairment related to our Canadian reporting unit due to the cumulative impact of non-core Canadian asset divestments, the shut-in of uneconomic natural gas production in Tommy Lakes and lower forecasted commodity prices. The net loss was also impacted by a $28.8 million loss on derivative instruments compared to a $20.2 million gain in the third quarter due to crude oil prices rising above the purchased put level on our put spreads.

Fourth quarter cash flow from operating activities and adjusted funds flow increased to $188.5 million and $178.9 million, respectively, from $159.8 million and $175.3 million, respectively, in the third quarter. Oil and gas sales, net of royalties, increased during the fourth quarter from the third quarter due to improved natural gas and natural gas liquids pricing, which was offset by an increase in operating costs due to additional well servicing activity. Adjusted funds flow in the fourth quarter benefited from a $13.9 million Alternative Minimum Tax (“AMT”) refund.

During the fourth quarter, we repurchased 2.7 million common shares for $23.7 million, bringing our total repurchases in 2019 to 18.2 million shares for total consideration of $178.8 million.

Selected Fourth Quarter Canadian and U.S. Financial Results

	Three months ended December 31, 2019			Three months ended December 31, 2018		
(millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	8,147	46,197	54,344	9,237	40,731	49,968
Natural gas liquids (bbls/day)	797	4,705	5,502	956	3,527	4,483
Natural gas (Mcf/day)	21,664	263,873	285,537	23,357	237,096	260,453
Total average daily production (BOE/day)	12,555	94,881	107,436	14,086	83,774	97,860
Pricing[2]						
Crude oil (per bbl)	$ 55.69	$ 69.26	$ 67.23	$ 33.76	$ 71.07	$ 64.18
Natural gas liquids (per bbl)	28.61	16.53	18.28	39.69	23.20	26.72
Natural gas (per Mcf)	2.53	2.50	2.50	3.74	4.33	4.28
Capital Expenditures						
Capital spending	$ 7.5	$ 91.9	$ 99.4	$ 13.5	$ 58.6	$ 72.1
Acquisitions	3.1	3.0	6.1	1.2	8.3	9.5
Divestments	0.3	—	0.3	0.9	(1.8)	(0.9)
Netback[3] **Before Hedging**						
Oil and natural gas sales	$ 49.5	$ 362.1	$ 411.6	$ 40.9	$ 368.3	$ 409.2
Royalties	(11.3)	(73.3)	(84.6)	(5.4)	(77.0)	(82.4)
Production taxes	(0.7)	(22.8)	(23.5)	(0.4)	(21.5)	(21.9)
Cash operating expenses	(18.2)	(61.3)	(79.5)	(17.8)	(45.1)	(62.9)
Transportation costs	(2.1)	(35.7)	(37.8)	(2.6)	(30.8)	(33.4)
Netback before hedging	$ 17.2	$ 169.0	$ 186.2	$ 14.7	$ 193.9	$ 208.6
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 28.8	$ —	$ 28.8	$ (253.7)	$ —	$ (253.7)
General and administrative expense[4]	8.7	10.1	18.8	11.6	7.5	19.1
Goodwill impairment	451.1	—	451.1	—	—	—
Current income tax recovery	—	(14.0)	(14.0)	—	(27.4)	(27.4)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See “Non-GAAP Measures” section in this MD&A.
(4) Includes share-based compensation.

Comparing the fourth quarter of 2019 with the same period in 2018:

- Average daily production was 107,436 BOE/day, an increase of 10% from 97,860 BOE/day, primarily due to a 15% increase in U.S. crude oil and natural gas liquids production as a result of the 42.3 net wells brought on-stream during 2019. Natural gas production also increased by 10% due to strong well performance in the Marcellus.

- Our crude oil and natural gas liquids production accounted for 56% of our total production mix in the fourth quarter of 2019, consistent with 2018.

- Capital spending increased to $99.4 million compared to $72.1 million in the fourth quarter of 2018 due to additional drilling activity in the fourth quarter of 2019. The majority of our capital investment in the fourth quarter was focused on our U.S. crude oil properties, with spending of $80.9 million.

- Operating expenses increased to $79.5 million ($8.05/BOE) compared to $62.9 million ($6.99/BOE) in the fourth quarter of 2018 as a result of higher fluid handling costs due to increased crude oil volumes and additional well servicing activity.

- Cash general and administrative ("G&A") expenses increased to $13.3 million compared to $12.6 million in 2018, but decreased on a per BOE basis to $1.34/BOE in 2019 from $1.40/BOE in the same period of 2018 with increased production.

- During the fourth quarter of 2019, our Bakken crude oil price differential improved to US$4.40/bbl below WTI, compared to US$5.60/bbl below WTI for the same period in 2018, as we did not experience the same level of refinery maintenance and demand reductions as we did in the fourth quarter of 2018. Our Marcellus natural gas differential widened in the fourth quarter of 2019 to US$0.63/Mcf below NYMEX compared to US$0.34/Mcf below NYMEX in 2018 due to relatively weak pricing in the quarter given above average storage levels.

- We reported a net loss of $429.1 million in the fourth quarter of 2019 compared to net income of $249.3 million in the fourth quarter of 2018. Net income decreased by $678.4 million primarily due to a non-cash goodwill impairment of $451.1 million related to the Canadian reporting unit. Earnings were further impacted by a $28.8 million loss on commodity derivative instruments recorded in 2019 compared to a $253.7 million gain in 2018.

- Cash flow from operating activities and adjusted funds flow decreased to $188.5 million and $178.9 million, respectively, compared to $221.6 million and $214.3 million, respectively, in the fourth quarter of 2018. The decreases were primarily the result of an increase in operating expenses and a lower AMT refund of $13.9 million in 2019, compared to $27.3 million in 2018.

- During the fourth quarter of 2019, we repurchased 2.7 million common shares under our Normal Course Issuer Bid ("NCIB") for total consideration of $23.7 million, compared to the repurchase of 5.4 million common shares for $70.6 million in the fourth quarter of 2018.

- Net debt to adjusted funds flow increased to 0.6x in the fourth quarter of 2019 compared to 0.4x in the fourth quarter of 2018.

2019 OVERVIEW AND 2020 OUTLOOK

Summary of Guidance and Results	Revised 2019 Guidance	2019 Results	2020 Guidance
Capital spending ($ millions)	$625	$619	$520 – $570
Average annual production (BOE/day)	100,000 - 101,000	101,042	96,000 – 100,000
Average annual crude oil and natural gas liquids production (bbls/day)	54,250 - 54,750	54,633	57,000 – 60,000
Fourth quarter average production (BOE/day)	103,000 - 107,000	107,436	—
Fourth quarter average crude oil and natural gas liquids production (bbls/day)	58,000 - 60,000	59,846	—
Average royalty and production tax rate (% of gross sales, before transportation)	25.0%	25.5%	26.0%
Operating expenses (per BOE)	$7.90	$7.88	$8.50
Transportation costs (per BOE)	$4.00	$3.93	$4.00
Cash G&A expenses (per BOE)	$1.40	$1.32	$1.50

Differential/Basis Outlook and Results(1)			
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.60)/bbl	US$(3.61)/bbl	US$(5.00)/bbl
Average Marcellus natural gas differential (compared to NYMEX natural gas)	US$(0.35)/Mcf	US$(0.39)/Mcf	US$(0.45)/Mcf

(1) Excludes transportation costs

2019 Overview

In 2019, we continued to focus on maximizing returns, delivering sustainable liquids production growth and returning capital to shareholders, while preserving our balance sheet strength. We delivered liquids production growth of 9% and overall production growth of 8% compared to 2018. In 2019, we returned $206.5 million of capital to our shareholders through share repurchases and dividends. Since initiating our share repurchase program in 2018, we have repurchased 24.5 million shares, or approximately 10% of shares outstanding, improving our per share metrics.

Our 2019 annual average production was 101,042 BOE/day with crude oil and natural gas liquids volumes of 54,633 bbls/day, meeting our revised production guidance targets of 100,000 – 101,000 BOE/day and 54,250 – 54,750 bbls/day, respectively. Our capital spending for the year totaled $618.9 million, slightly below our revised guidance of $625 million. The majority of our capital was directed to our U.S. oil properties, with 86% of total spending focused on our North Dakota and Colorado properties.

Our Bakken sales price differentials remained consistent with the prior year averaging US$3.61/bbl below WTI, which was in line with our revised guidance of US$3.60/bbl below WTI. Our Marcellus differential was also consistent with the prior year at US$0.39/Mcf below NYMEX and in line with our revised differential outlook of $0.35/Mcf below NYMEX.

Operating expenses and cash G&A expenses were $7.88/BOE and $1.32/BOE, respectively, meeting our revised guidance of $7.90/BOE and $1.40/BOE, respectively.

Our net loss for 2019 was $259.7 million, a decrease from net income of $378.3 million in 2018 primarily due to a non-cash impairment of $451.1 million on goodwill associated with our Canadian assets. Our earnings were also impacted by a loss on commodity derivative instruments of $66.1 million compared to a gain of $88.2 million recorded in 2018.

Cash flow from operations and adjusted funds flow decreased to $694.2 million and $709.0 million, respectively, from $738.8 million and $753.5 million, respectively, in 2018. Oil and natural gas sales decreased due to lower realized commodity prices while operating expenses increased over the same period, in part due to higher liquids volumes and additional well servicing activity.

Total debt net of cash at December 31, 2019 was $455.0 million, comprised of $606.6 million of senior notes less $151.6 million in cash. At December 31, 2019, we were undrawn on our US$600 million senior unsecured bank credit facility and had a net debt to adjusted funds flow ratio of 0.6x.

2020 Outlook

In 2020, we plan to continue to focus on creating value for shareholders though sustainable liquids production growth balanced with the generation of free cash flow while maintaining our low financial leverage. Our capital budget range for 2020 is between $520 million and $570 million, with the majority of capital being allocated to our North Dakota crude oil properties. As a result, we expect annual liquids production of 57,000 – 60,000 bbls/day, representing growth of approximately 7% at the mid-point.

Annual 2020 production is expected to average between 96,000 – 100,000 BOE/day. With lower capital spending in the fourth quarter of 2019, we expect strong crude oil and natural gas liquids growth to occur in the second half of the year. Natural gas production is expected to decline in 2020 due to limited capital activity in the Marcellus and the shut-in of Tommy Lakes, a Canadian asset with approximately 1,600 BOE/day (90% natural gas) of average annual production.

Our Bakken sales price differential is expected to widen to US$5.00/bbl below WTI in 2020, as production growth in the basin continues to exceed pipeline capacity. In the Marcellus, we have a differential outlook of US$0.45/Mcf below NYMEX, which is similar to 2019.

To support our 2020 capital program, we have hedged 61% of our 2020 forecasted net crude oil production, at an average floor price of $56.87/bbl primarily through the use of swaps, put spreads and three-way collar structures.

Operating expenses are expected to average approximately $8.50/BOE in 2020, an increase from 2019 as a result of the higher expected crude oil and natural gas liquids weighting of 60% in 2020 from 54% in 2019. Our capital program continues to focus on crude oil production growth, which has higher associated operating cost metrics.

We expect cash G&A expenses and transportation costs for 2019 to average approximately $1.50/BOE and $4.00/BOE, respectively, consistent with 2019.

RESULTS OF OPERATIONS

Production

Average Daily Production Volumes	2019	2018	2017
Crude oil (bbls/day)	49,704	45,424	36,935
Natural gas liquids (bbls/day)	4,929	4,486	3,858
Natural gas (Mcf/day)	278,451	259,837	263,506
Total daily sales (BOE/day)	101,042	93,216	84,711

Production in 2019 averaged 101,042 BOE/day, in line with our revised production guidance range of 100,000 – 101,000 BOE/day and an 8% increase when compared to 2018 production of 93,216 BOE/day. Crude oil and natural gas liquids production in 2019 increased 9% from 2018, averaging 54,633 bbls/day, at the high end of our revised guidance range of 54,250 – 54,750 bbls/day.

Our total U.S. production volumes increased by 12%, compared to 2018 and our U.S. crude oil and natural gas liquids production increased by 14% to 45,113 bbls/day, largely due to the 42.3 net wells brought on-stream in North Dakota and Colorado during 2019. Our U.S. natural gas production increased by 10% due to strong well performance in the Marcellus in 2019.

Canadian production volumes decreased by 1,458 BOE/day compared to the prior year, due to both natural base decline and the sale of certain Canadian assets during 2019 with associated production of approximately 350 bbls/day.

Our crude oil and natural gas liquids production accounted for 54% of our total average daily production in 2019 and 2018, an increase from 48% in 2017.

Production for 2018 increased by 8,505 BOE/day to 93,216 BOE/day, compared to 2017. The 10% increase was largely due to an increase to the 2018 capital spending program and strong well performance in North Dakota. During the same period, U.S. natural gas production increased 7% with no price related curtailments in the Marcellus.

2020 Guidance

We expect annual average production for 2020 of 96,000 – 100,000 BOE/day, including 57,000 – 60,000 bbls/day of crude oil and natural gas liquids, resulting in year over year liquids production growth of 7% at the midpoint.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, cash flow from operating activities, adjusted funds flow and financial condition. The following table summarizes our average selling prices, benchmark prices and differentials:

Pricing (average for the period)	2019	2018	2017
Benchmarks			
WTI crude oil (US$/bbl)	$ 57.03	$ 64.77	$ 50.95
Brent (ICE) crude oil (US$/bbl)	64.18	71.53	54.83
NYMEX natural gas – last day (US$/Mcf)	2.63	3.09	3.11
USD/CDN average exchange rate	1.33	1.30	1.30
USD/CDN period end exchange rate	1.30	1.36	1.26
Enerplus selling price(1)			
Crude oil ($/bbl)	$ 68.98	$ 74.59	$ 58.69
Natural gas liquids ($/bbl)	15.19	28.31	30.01
Natural gas ($/Mcf)	2.87	3.42	3.21
Average benchmark differentials			
Bakken DAPL - WTI (US$/bbl)	$ (3.46)	$ (3.73)	$ (0.68)
Brent (ICE) - WTI (US$/bbl)	7.15	6.77	3.88
MSW Edmonton – WTI (US$/bbl)	(4.88)	(11.12)	(2.46)
WCS Hardisty – WTI (US$/bbl)	(12.76)	(26.31)	(11.98)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.46)	(0.64)	(0.96)
Transco Z6 Non-New York monthly – NYMEX (US$/Mcf)	0.23	0.75	(0.04)
Enerplus realized differentials(1)(2)			
Bakken crude oil – WTI (US$/bbl)	$ (3.61)	$ (3.78)	$ (3.72)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.39)	(0.43)	(0.76)
Canada crude oil – WTI (US$/bbl)	(12.11)	(21.83)	(10.94)

(1) Excluding transportation costs, royalties and the effects of commodity derivative instruments.
(2) Based on a weighted average differential for the period.

CRUDE OIL AND NATURAL GAS LIQUIDS

Benchmark WTI prices decreased by 12% to US$57.03/bbl in 2019 compared to 2018, largely due to continued growth in international crude oil supplies, particularly in the U.S. Permian Basin. In an effort to provide ongoing support for crude oil prices, the Organization of Petroleum Exporting Countries (“OPEC”) continued its policy of production curtailment by extending and reducing production quotas for member nations in 2019. Our 2019 realized crude oil price averaged $68.98/bbl, an 8% decrease compared to 2018, outperforming the 12% decrease in the benchmark as a result of narrower Bakken and Canadian crude oil differentials.

Our Bakken sales price differentials strengthened slightly in 2019 compared to 2018, averaging US$3.61/bbl below WTI, in line with our revised guidance of US$3.60/bbl below WTI. Bakken prices were strong in the first three quarters of 2019 but weakened late in the year due to growth in regional production that exceeded available demand and pipeline takeaway capacity, as well as a reduction in Brent/WTI spreads, which reduced the price for crude oil transported to the U.S. Gulf Coast. Our realized Bakken differential was protected from much of the price weakness in the fourth quarter as a significant portion of our physical sales were based on fixed differentials to WTI, and U.S. Gulf Coast and Brent crude oil prices. We expect our Bakken differentials to average US$5.00/bbl below WTI in 2020 due to regional production remaining above pipeline takeaway capacity.

Canadian crude oil differentials tightened substantially in 2019, improving by 45% compared to 2018 to average US$12.11/bbl below WTI. The strength in differentials was largely due to the implementation of government mandated production curtailments in Alberta at the start of the year. These production curtailments remain in effect, but were reduced late in 2019.

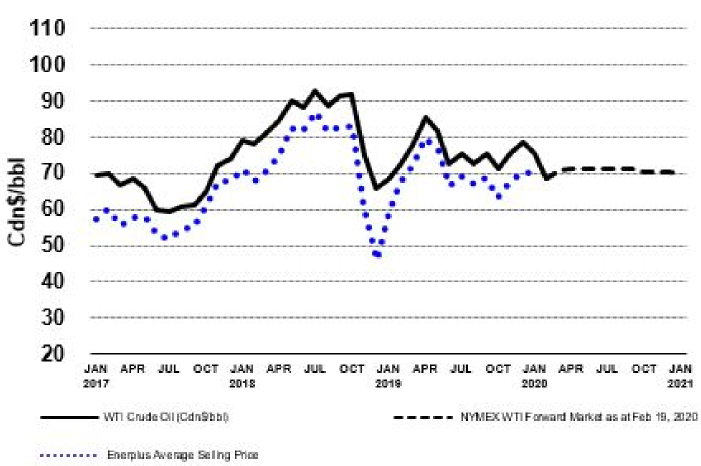
We realized an average price of $15.19/bbl on our natural gas liquids production in 2019, which represents a 46% decline compared to 2018. This decrease was due to a considerable increase and oversupply of natural gas liquids into key markets in Canada and the U.S., most predominantly for propane and butane.

NATURAL GAS

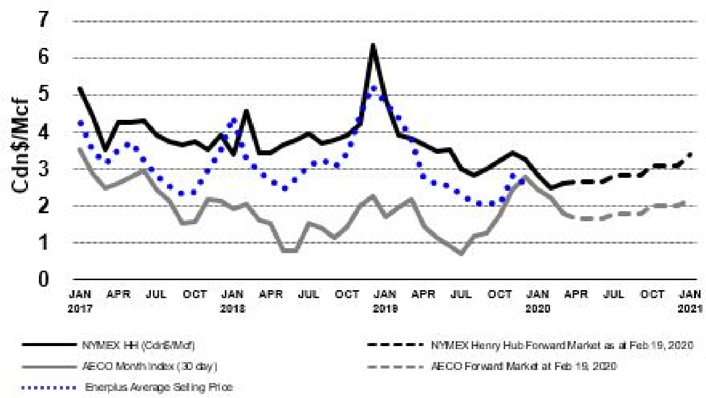
Our realized natural gas price averaged $2.87/Mcf in 2019, a 16% decrease from 2018 realized prices, in line with the corresponding decrease in benchmark NYMEX prices.

In the Marcellus, we realized an average sales price differential of US$0.39/Mcf below NYMEX, in line with our revised guidance of US$0.35/Mcf below NYMEX for the year and a slight improvement compared to our 2018 realized sales differential of US$0.43/Mcf below NYMEX. The Transco Leidy monthly benchmark differential averaged US$0.46/Mcf below NYMEX for 2019, which was stronger than 2018 as the market benefited from the additional pipeline egress that was brought into service in late 2018. Transco Z6 Non-New York Leidy monthly benchmark differentials averaged US$0.23/Mcf above NYMEX for 2019, substantially weaker than 2018 due to warmer than expected weather in the region in the fourth quarter of 2019. This resulted in a significant reduction in heating demand and much lower prices compared to the same period last year. We expect our Marcellus differential to average US$0.45/Mcf below NYMEX in 2020.

Monthly Crude Oil Prices



Monthly Natural Gas Prices

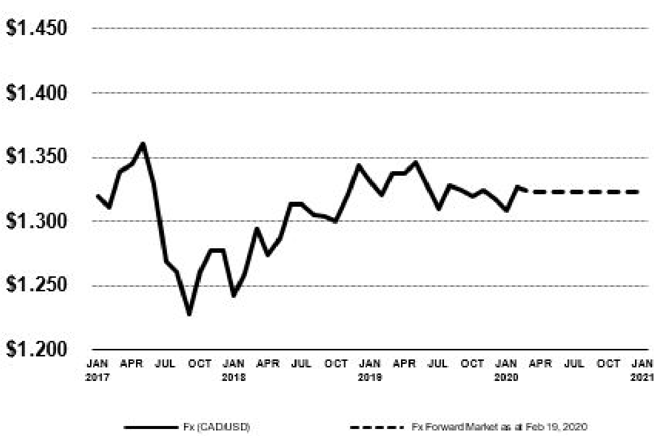


FOREIGN EXCHANGE

Our oil and natural gas sales are impacted by foreign exchange fluctuations as the majority of our sales are based on U.S. dollar denominated benchmark indices. A stronger Canadian dollar decreases the amount of our realized sales, as well as the amount of our U.S. denominated costs, such as capital, interest on our U.S. denominated debt, and the value of our outstanding U.S. senior notes.

The Canadian dollar strengthened at the end of the year to close at 1.30 USD/CDN compared to 1.36 USD/CDN at December 31, 2018 and averaging 1.33 USD/CDN throughout the year compared to an average of 1.30 in 2018. The weaker Canadian dollar throughout 2019 was influenced by trade uncertainty resulting from changing U.S. and Canada trade policies, including the renegotiation of the North America Free Trade Agreement.

Monthly USD/CDN Exchange Rate



Price Risk Management

We have a price risk management program that considers our overall financial position and the economics of our capital expenditures.

As of February 20, 2020, we have hedged approximately 24,000 bbls/day of our expected crude oil production for 2020, which represents approximately 61% of our 2020 forecasted crude oil production, net of royalties, at the midpoint of guidance. Our crude oil hedges are a mix of swaps, put spreads and three way collars. The put spreads and three way collars provide us with exposure to significant upward price moves; however, the sold put effectively limits the amount of downside protection we have to the difference between the strike price of the purchased and sold puts. Overall, we expect our crude oil related hedging contracts to protect a significant portion of our cash flow from operating activities and adjusted funds flow in 2020.

The following is a summary of our financial contracts in place at February 20, 2020, expressed as a percentage of our forecasted 2020 net production volumes:

	WTI Crude Oil (US$/bbl)[1]				
	Jan 1, 2020 – Jan 31, 2020	**Feb 1, 2020 – Mar 31, 2020**	**Apr 1, 2020 – Jun 30, 2020**	**Jul 1, 2020 – Sep 30, 2020**	**Oct 1, 2020 – Dec 31, 2020**
Swaps					
Volume (bbls/d)	5,000	10,000	12,000	2,000	-
Sold Swaps	$ 57.05	$ 54.56	$ 55.23	$ 57.18	-
%	13%	25%	31%	5%	-
Put Spreads[2]					
Volume (bbls/d)	16,000	16,000	16,000	16,000	16,000
Sold Puts	$ 46.88	$ 46.88	$ 46.88	$ 46.88	$ 46.88
Purchased Puts	$ 57.50	$ 57.50	$ 57.50	$ 57.50	$ 57.50
%	41%	41%	41%	41%	41%
Three Way Collars[2]					
Volume (bbls/d)	-	-	-	5,000	5,000
Sold Puts	-	-	-	$ 48.00	$ 48.00
Purchased Puts	-	-	-	$ 56.25	$ 56.25
Sold Calls	-	-	-	$ 65.00	$ 65.00
%	-	-	-	12%	12%

(1) Based on weighted average price (before premiums) assuming average annual production of 98,000 BOE/day, which is the mid-point of our annual 2020 guidance, less royalties and production taxes of 26%. A portion of the sold puts are settled annually rather than monthly.
(2) The total average deferred premium spent on our outstanding hedges is US$1.69/bbl from January 1, 2020 to December 31, 2020.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)

($ millions)	**2019**	**2018**	**2017**
Cash gains/(losses):			
Crude oil	$ (12.1)	$ (52.0)	$ 0.9
Natural gas	27.4	16.2	7.7
Total cash gains/(losses)	$ 15.3	$ (35.8)	$ 8.6
Non-cash gains/(losses):			
Crude oil	$ (70.5)	$ 114.8	$ (5.4)
Natural gas	(10.9)	9.2	11.1
Total non-cash gains/(losses)	$ (81.4)	$ 124.0	$ 5.7
Total gains/(losses)	$ (66.1)	$ 88.2	$ 14.3

(Per BOE)	**2019**	**2018**	**2017**
Total cash gains/(losses)	$ 0.42	$ (1.05)	$ 0.28
Total non-cash gains/(losses)	(2.21)	3.64	0.18
Total gains/(losses)	$ (1.79)	$ 2.59	$ 0.46

During 2019, we realized cash losses of $12.1 million on crude oil contracts and cash gains of $27.4 million on natural gas contracts. In comparison, in 2018, we realized cash losses of $52.0 million on crude oil contracts and cash gains of $16.2 million on natural gas contracts. Cash losses in 2019 on crude oil contracts were primarily due to premiums paid on expiring three way collars. For the same period, cash gains on natural gas contracts resulted from natural gas prices falling below the swap level.

As the forward markets for crude oil and natural gas fluctuate, as new contracts are executed, and as existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. The fair value of our crude oil contracts at December 31, 2019 was a net asset position of $10.1 million (December 31, 2018 – net asset position of $80.5 million). All natural gas contracts were settled in the fourth quarter of 2019 resulting in a fair value of nil (December 31, 2018 – asset position of $10.9 million). The change in fair value of our crude oil and natural gas contracts represented losses of $70.5 million and $10.9 million, respectively, during 2019 and gains of $114.8 million and of $9.2 million, respectively, during 2018.

Revenues

($ millions)	2019	2018	2017
Oil and natural gas sales	$ 1,572.9	$ 1,610.9	$ 1,141.8
Royalties	(318.1)	(318.2)	(221.1)
Oil and natural gas sales, net of royalties	$ 1,254.8	$ 1,292.7	$ 920.7

Oil and natural gas sales revenue for 2019 totaled $1,572.9 million, a decrease of 2% from $1,610.9 million in 2018. The decrease in revenue was a result of lower commodity prices which more than offset the increase in production.

Oil and natural gas sales revenue for 2018 totaled $1,610.9 million, an increase of 41% from $1,141.8 million in 2017. The increase in revenue was a result of higher liquids production and an improvement in crude oil prices.

Royalties and Production Taxes

($ millions, except per BOE amounts)	2019	2018	2017
Royalties	$ 318.1	$ 318.2	$ 221.1
Per BOE	$ 8.63	$ 9.35	$ 7.15
Production taxes	$ 83.1	$ 87.3	$ 54.3
Per BOE	$ 2.25	$ 2.57	$ 1.76
Royalties and production taxes	$ 401.2	$ 405.5	$ 275.4
Per BOE	$ 10.88	$ 11.92	$ 8.91
Royalties and production taxes (% of oil and natural gas sales)	25.5%	25.2%	24.1%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees and freehold mineral taxes. A large percentage of our production is from U.S. properties where royalty rates are generally higher than in Canada and less sensitive to commodity price levels.

Royalties and production taxes were in line with our guidance of 25% for 2019, averaging 25.5% of oil and natural gas sales, before transportation. Royalties and production taxes of $401.2 million in 2019 were consistent with the prior year, but decreased on a per BOE basis due to lower realized commodity prices. Royalties and production taxes increased to $405.5 million in 2018 from $275.4 million in 2017, mainly due to a larger portion of production volumes coming from our U.S. properties, as well as higher crude oil and natural gas realized prices.

2020 Guidance

We expect royalty and production taxes in 2020 to average 26% of our oil and gas sales before transportation.

Operating Expenses

($ millions, except per BOE amounts)	2019	2018	2017
Cash operating expenses	$ 290.8	$ 238.3	$ 197.7
Non-cash (gains)/losses(1)	—	—	(0.6)
Total operating expenses	$ 290.8	$ 238.3	$ 197.1
Per BOE	$ 7.88	$ 7.00	$ 6.37

(1) Non-cash (gains)/losses on fixed price electricity swaps.

Operating expenses for 2019 were $290.8 million or $7.88/BOE, consistent with our revised guidance of $7.90/BOE and representing an increase of $52.5 million or $0.88/BOE from the prior year. The increase is largely due to additional well servicing activity, higher fluid handling costs and gas processing charges related to our North Dakota asset.

Operating expenses for 2018 were $238.3 million or $7.00/BOE, representing an increase of $41.2 million or $0.63/BOE from 2017. The increase is mainly attributable to higher liquids production as our liquids weighting increased to 54% from 48% in 2017. Our liquids production has higher associated operating cost metrics, which was partially offset by the divestment of higher operating cost Canadian properties during 2017.

2020 Guidance

We expect operating expenses of $8.50/BOE in 2020, an increase from 2019 primarily as a result of our crude oil and natural gas liquids growth, which has a higher associated cost.

Transportation Costs

($ millions, except per BOE amounts)	2019	2018	2017
Transportation costs	$ 144.9	$ 123.5	$ 111.3
Per BOE	$ 3.93	$ 3.63	$ 3.60

Transportation costs in 2019 were in line with our guidance of $4.00/BOE averaging $3.93/BOE, an increase from $3.63/BOE reported in 2018. The increased costs were due to additional crude oil firm transportation commitments that provide access to sell a portion of our production at U.S. Gulf Coast or Brent pricing that commenced March 1, 2019. Transportation costs in 2018 were $3.63/BOE, consistent with $3.60/BOE in 2017.

2020 Guidance

We expect transportation costs of $4.00/BOE in 2020.

Netbacks

The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section of this MD&A.

	Year ended December 31, 2019		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	58,679 BOE/day	254,177 Mcfe/day	101,042 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 60.60	$ 2.97	$ 42.65
Royalties and production taxes	(16.30)	(0.56)	(10.88)
Cash operating expenses	(12.23)	(0.31)	(7.88)
Transportation costs	(2.97)	(0.88)	(3.93)
Netback before hedging	$ 29.10	$ 1.22	$ 19.96
Cash gains/(losses)	(0.57)	0.30	0.42
Netback after hedging	$ 28.53	$ 1.52	$ 20.38
Netback before hedging ($ millions)	$ 623.3	$ 112.7	$ 736.0
Netback after hedging ($ millions)	$ 611.1	$ 140.3	$ 751.4

	Year ended December 31, 2018		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	53,294 BOE/day	239,532 Mcfe/day	93,216 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 67.43	$ 3.42	$ 47.35
Royalties and production taxes	(17.90)	(0.65)	(11.92)
Cash operating expenses	(10.54)	(0.38)	(7.00)
Transportation costs	(2.40)	(0.88)	(3.63)
Netback before hedging	$ 36.59	$ 1.51	$ 24.80
Cash gains/(losses)	(2.67)	0.19	(1.05)
Netback after hedging	$ 33.92	$ 1.70	$ 23.75
Netback before hedging ($ millions)	$ 711.7	$ 131.9	$ 843.6
Netback after hedging ($ millions)	$ 659.7	$ 148.1	$ 807.8

(1) See "Non-GAAP Measures" in this MD&A.

Netbacks by Property Type		Year ended December 31, 2017 Crude Oil		Natural Gas		Total
Average Daily Production		44,496 BOE/day		241,290 Mcfe/day		84,711 BOE/day
Netback[1] $ per BOE or Mcfe		(per BOE)		(per Mcfe)		(per BOE)
Oil and natural gas sales	$	53.38	$	3.12	$	36.93
Royalties and production taxes		(13.89)		(0.57)		(8.91)
Cash operating expenses		(10.20)		(0.36)		(6.39)
Transportation costs		(2.21)		(0.86)		(3.60)
Netback before hedging	$	27.08	$	1.33	$	18.03
Cash gains/(losses)		0.06		0.09		0.28
Netback after hedging	$	27.14	$	1.42	$	18.31
Netback before hedging ($ millions)	$	439.8	$	117.6	$	557.4
Netback after hedging ($ millions)	$	440.7	$	125.2	$	566.0

(1) See “Non-GAAP Measures” in this MD&A.

Crude oil and natural gas netbacks per BOE before hedging were lower during 2019 compared to 2018 primarily due to lower realized crude oil prices. During 2019, our crude oil properties accounted for 85% and 81% of our netback before and after hedging, respectively. During 2018, our crude oil properties accounted for 84% and 82% of our netback before and after hedging, respectively.

General and Administrative Expenses

Total G&A expenses include cash G&A expenses and share-based compensation (“SBC”) charges related to our long-term incentive plans (“LTI plans”). See Note 11, Note 14 and Note 15 to the Financial Statements for further details.

($ millions)		2019		2018		2017
Cash:						
G&A expense	$	48.8	$	50.0	$	50.5
Share-based compensation expense		0.7		0.1		1.0
Non-Cash:						
Share-based compensation expense		22.3		25.9		22.6
Equity swap loss/(gain)		0.3		(0.2)		0.2
G&A expense		0.7		—		—
Total G&A expenses	$	72.8	$	75.8	$	74.3

(Per BOE)		2019		2018		2017
Cash:						
G&A expense	$	1.32	$	1.47	$	1.63
Share-based compensation expense		0.02		0.01		0.03
Non-Cash:						
Share-based compensation expense		0.61		0.76		0.73
Equity swap loss/(gain)		0.01		(0.01)		0.01
G&A Expense		0.02		—		—
Total G&A expenses	$	1.98	$	2.23	$	2.40

Cash G&A expenses were $48.8 million or $1.32/BOE in 2019, beating our revised guidance of $1.40/BOE and consistent with our 2018 Cash G&A of $50.0 million or $1.47/BOE.

During 2019, we reported cash SBC on our Deferred Share Unit plan for Directors of $0.7 million, compared to $0.1 million in 2018. We recorded non-cash SBC of $22.3 million or $0.61/BOE in 2019 compared to $25.9 million or $0.76/BOE in 2018. The decrease in non-cash SBC in 2019 was a result of a lower multiplier on our Performance Share Units (“PSU”) compared to 2018.

Cash G&A expenses in 2018 were $50.0 million or $1.47/BOE, a decrease from $50.5 million or $1.63/BOE in 2017, mostly due to an increase in our production over the period. Cash SBC expense was $0.1 million or $0.01/BOE in 2018 compared to an expense of $1.0 million or $0.03/BOE in 2017. We recorded non-cash SBC of $25.9 million or $0.76/BOE in 2018 compared to $22.6 million or $0.73/BOE in 2017. The increase in non-cash SBC was a result of the increased forfeiture of units in 2017.

We have hedged a portion of the outstanding cash-settled units under our LTI plans. We recorded a non-cash mark-to-market loss of $0.3 million on these hedges in 2019 (2018 – $0.2 million gain; 2017 – $0.2 million loss). As of December 31, 2019, we have 264,000 units hedged at a weighted average price of $17.82 per share.

2020 Guidance

We expect cash G&A expense of $1.50/BOE in 2020.

Interest Expense

Interest on our senior notes and bank credit facility for 2019 totaled $33.9 million, a decrease of 8% from $36.8 million in 2018. The decrease is due to the repayment of a portion of our 2009 senior notes and the bullet repayment of the full principal amount of our 2012 $30 million senior notes in the second quarter of 2019.

Interest on our senior notes and bank credit facility for 2018 totaled $36.8 million compared to $38.7 million in 2017. The decrease is due to our undrawn bank credit facility and the repayment of a portion of our 2009 senior notes in 2018.

At December 31, 2019, we were undrawn on our US$600 million bank credit facility and our debt consisted of fixed interest rate senior notes with a weighted average interest rate of 4.6%. See Note 7 to the Financial Statements for further details on our outstanding notes.

Foreign Exchange

($ millions)	2019	2018	2017
Realized:			
Foreign exchange loss/(gain) on settlements	$ (0.1)	$ 0.5	$ 1.5
Translation of U.S. dollar cash held in Canada loss/(gain)	8.8	(19.6)	11.0
Unrealized loss/(gain)	(34.1)	58.6	(42.6)
Total foreign exchange loss/(gain)	$ (25.4)	$ 39.5	$ (30.1)
USD/CDN average exchange rate	1.33	1.30	1.30
USD/CDN period end exchange rate	1.30	1.36	1.26

We recorded a net foreign exchange gain of $25.4 million in 2019 compared to a loss of $39.5 million in 2018 and a gain of $30.1 million in 2017. Realized gains and losses relate primarily to day-to-day transactions recorded in foreign currencies and the translation of our U.S. dollar denominated cash held in Canada, while unrealized gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period-end.

In 2019, we recorded a realized foreign exchange loss of $8.7 million compared to a gain of $19.1 million recorded in the prior year.

Comparing December 31, 2019 to December 31, 2018, the Canadian dollar strengthened relative to the U.S. dollar, resulting in an unrealized gain of $34.1 million. See Note 12 to the Financial Statements for further details.

Capital Investment

($ millions)	2019	2018	2017
Capital spending[(1)]	$ 618.9	$ 593.9	$ 458.0
Office capital[(1)]	5.8	6.5	2.7
Line fill	5.1	—	—
Sub-total	629.8	600.4	460.7
Property and land acquisitions	$ 24.4	$ 25.8	$ 13.3
Property divestments	(9.6)	(6.9)	(56.2)
Sub-total	14.8	18.9	(42.9)
Total	$ 644.6	$ 619.3	$ 417.8

(1) Excludes changes in non-cash investing working capital. See Note 18(b) of the Consolidated Financial Statements for additional information.

2019

Capital spending in 2019 totaled $618.9 million, slightly lower than our revised guidance of $625 million. In 2019, we spent $531.7 million on our U.S. crude oil properties, $34.8 million on our Canadian crude oil properties and $49.3 million on our Marcellus natural gas assets. Through our capital program in 2019, we added 51.0 MMBOE of gross proved plus probable reserves, replacing 139% of our 2019 production, before accounting for acquisitions and divestments. In 2019, we spent $5.1 million on line fill to meet the requirements of a multi-year transportation contract that began in March 2019.

Property and land acquisitions in 2019 totaled $24.4 million and consisted primarily of undeveloped land in North Dakota. We recorded net divestments of $9.6 million related to the sale of properties in southeastern Saskatchewan with associated production of approximately 350 bbls/day.

2018

Capital spending in 2018 totaled $593.9 million, 30% higher than 2017. In 2018, we spent $474.4 million on our U.S. crude oil properties, $46.3 million on our Canadian crude oil properties, and $66.2 million on our Marcellus natural gas assets. In 2018, we added 65.7 MMBOE of gross proved plus probable reserves, replacing 194% of our 2018 production, before accounting for acquisitions and divestments.

Property and land acquisitions in 2018 totaled $25.8 million and included land acquisitions in Colorado and a property swap in North Dakota. We recorded net divestments of $6.9 million in 2018, primarily related to a property swap in North Dakota.

2017

Capital spending in 2017 totaled $458.0 million and was more than twice our spending levels in 2016, as we repositioned ourselves for growth. In 2017 we spent $343.0 million on our U.S. crude oil properties, $55.3 million on our Canadian crude oil properties, and $58.5 million on our Marcellus natural gas assets. In 2017, we added 58.0 MMBOE of gross proved plus probable reserves, replacing 189% of our 2017 production, before accounting for acquisitions and divestments.

We recorded net divestment proceeds of $56.2 million in 2017 consisting mainly of our second quarter sale of our Brooks waterflood property and Canadian shallow gas assets. Total divestments had combined production of 7,700 BOE/day and resulted in a $72.3 million reduction to future asset retirement obligations. Property and land acquisitions in 2017 totaled $13.3 million and included additional leases and minor undeveloped land.

2020 Guidance

Our capital spending guidance for 2020 is between $520 million and $570 million, and is expected to deliver annual liquids production growth of 7% at the midpoint of guidance. Our spending is focused on our core areas, with approximately $450 million allocated to North Dakota, $45 million to Canadian crude oil waterflood properties, $25 million to Marcellus gas properties, and $25 million to Colorado.

Gain on Asset Sales

Under full cost accounting rules, divestments of oil and natural gas properties are generally accounted for as adjustments to the full cost pool with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would significantly alter the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss must be recognized. No gains or losses were recorded on asset sales in 2019 and 2018. We recorded gains of $78.4 million during 2017 related to the divestment of our Brooks waterflood property and Canadian shallow gas assets.

Depletion, Depreciation and Accretion ("DD&A")

($ millions, except per BOE amounts)	2019	2018	2017
DD&A expense	$ 356.8	$ 304.3	$ 250.8
Per BOE	$ 9.68	$ 8.94	$ 8.11

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. Total DD&A in 2019 increased to $356.8 million from $304.3 million in 2018 mainly due to an 8% percent increase in overall production. On a per BOE basis, DD&A for 2019 increased as a result of higher capital spending and additional future development capital associated with undeveloped reserve additions.

Impairments

PP&E

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country cost centre basis using estimated after-tax future net cash flows discounted at 10 percent from proved reserves ("Standardized Measure"), using constant prices as defined by the U.S. Securities and Exchange Commission ("SEC"). SEC prices are calculated as the unweighted average of the trailing twelve first-day-of-the-month commodity prices. The Standardized Measure is not related to Enerplus' investment criteria and is not a fair value-based measurement, but rather a prescribed accounting calculation. Impairments are non-cash and are not reversed in future periods under U.S. GAAP.

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the value of impairment losses from future ceiling tests. For the upcoming year, the primary factors include future first-day-of-the-month commodity prices, reserves revisions, capital expenditure levels and timing, acquisition and divestment activity, as well as production levels, which impact DD&A expense. There have been no PP&E impairments recorded in 2019, 2018 or 2017.

The following table outlines the twelve-month average trailing benchmark prices and exchange rates used in our ceiling test at December 31, 2019, 2018 and 2017:

Year	WTI Crude Oil US$/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	Exchange Rate USD/CDN
2019	$ 55.85	$ 66.73	$ 2.58	1.33
2018	$ 65.56	$ 69.58	$ 3.10	1.28
2017	$ 51.34	$ 63.57	$ 2.98	1.30

Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. The portion of goodwill that relates to U.S. operations fluctuates due to changes in foreign exchange rates. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

Goodwill is assessed for impairment annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus first performs a qualitative assessment to determine whether events or changes in circumstances indicate that goodwill may be impaired. If it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value, with an offsetting non-cash charge to earnings in the Consolidated Statements of Income/(Loss). The loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. For the purposes of goodwill impairment testing, Enerplus has two reporting units.

We recorded a non-cash goodwill impairment of $451.1 million in 2019 related to our Canadian reporting unit. The cumulative impact of Canadian asset dispositions, the shut-in of uneconomic natural gas production in Tommy Lakes and lower forecasted commodity prices resulted in a reduction to the fair value of the reporting unit.

Asset Retirement Obligation

In connection with our operations, we incur abandonment, reclamation and remediation costs related to assets, such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are based on management's estimate of our net ownership interest, costs to abandon, reclaim and remediate and the timing of the costs to be incurred in future periods.

We have estimated the net present value of our asset retirement obligation to be $138.0 million at December 31, 2019, compared to $126.1 million at December 31, 2018. The increase was largely due to a decrease in our weighted average credit-adjusted risk-free rate used to determine the net present value of the liability. See Note 8 to the Financial Statements for further information.

We take an active approach to managing our abandonment, reclamation and remediation obligations. During 2019, we spent $16.7 million (2018 – $11.3 million) on our asset retirement obligations and we expect to spend approximately $16.0 million in 2020. The majority of our abandonment, reclamation and remediation costs are expected to be incurred between 2025 and 2055. We do not reserve cash or assets for the purpose of funding our future asset retirement obligations. Any abandonment, reclamation and remediation costs are anticipated to be funded out of adjusted funds flow and our bank credit facility.

Leases

On January 1, 2019, we adopted ASU 842 – Leases, which requires the recognition of Right-Of-Use ("ROU") assets and lease liabilities on the Consolidated Balance Sheet for qualifying leases with a term greater than 12 months. We incur lease payments related to office space, drilling rig commitments, vehicles and other equipment. Total lease liabilities included on our balance sheet are based on the present value of lease payments over the lease term. Total ROU assets included on our balance sheet represent our right to use an underlying asset for the lease term. At December 31, 2019, our total lease liability was $53.1 million. In addition, ROU assets of $48.7 million were recorded, which equate to our lease liabilities less lease incentives. See Note 2(p) and Note 9 to the Consolidated Financial Statements for further details.

Income Taxes

($ millions)	2019	2018	2017
Current tax expense/(recovery)	$ (33.4)	$ (27.1)	$ (48.0)
Deferred tax expense/(recovery)	81.3	130.3	129.9
Total tax expense/(recovery)	$ 47.9	$ 103.2	$ 81.9

In 2019, we had a current tax recovery of $33.4 million compared to $27.1 million in 2018 and $48.0 million in 2017. The recovery in 2019 primarily relates to the favorable settlement of a tax dispute in Canada of $13.9 million and the reclassification of our AMT refund from our deferred income tax asset of $13.9 million. The recoveries in 2018 and 2017 are primarily related to the AMT reclassification of $27.2 million and $50.1 million, respectively. The final AMT refund of $13.9 million is expected to be recognized in 2020.

The deferred tax expense in 2019 was $81.3 million compared to $130.3 million in 2018 and $129.9 million in 2017. The deferred tax expense in 2019 included a $22.7 million expense from the remeasurement of our net Canadian deferred income tax assets for the change in Alberta corporate income tax rate from 12% to 8% by 2022. The deferred tax expense in 2017 included $46.2 million from the remeasurement of our U.S. net deferred income tax assets for the federal income tax rate reduction from 35% to 21% after enactment of the U.S. Tax Cuts and Jobs Act, offset by the reversal of the valuation allowance previously recorded on our AMT credit carryovers.

We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not all or a portion of our deferred income tax assets will be realized. We consider available positive and negative evidence including future taxable income and reversing existing temporary differences in making this assessment. Our overall deferred income tax asset, net of valuation allowance, is $372.5 million as at December 31, 2019 (2018 - $465.1 million). Our remaining valuation allowance is primarily related to our capital loss carryforward balance. We do not anticipate future capital gains that will allow us to utilize these losses.

Our estimated tax pools at December 31, 2019 are as follows:

Pool Type ($ millions)	2019
Canada	
Canadian oil and gas property	$ 5
Canadian development expenditures	107
Canadian exploration expenditures	238
Undepreciated capital costs	160
Non-capital losses and other credits	419
	$ 929
U.S.	
Net operating losses	$ 991
Depletable and depreciable assets	929
	$ 1,920
Total tax pools and credits	$ 2,849
Capital losses	$ 1,170

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage, including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging, share repurchases and dividend levels. We also assess our leverage relative to our most restrictive debt covenant, which is a maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. Our senior debt to adjusted EBITDA ratio was 0.9x at December 31, 2019, consistent with December 31, 2018. Our net debt to adjusted funds flow ratio increased to 0.6x at December 31, 2019 from 0.4x at December 31, 2018. Although it is not included in our debt covenants, the net debt to adjusted funds flow ratio is often used by investors and analysts to evaluate our liquidity.

Total debt net of cash at December 31, 2019 increased to $455.0 million, compared to $333.5 million at December 31, 2018. Total debt was comprised of $606.6 million in senior notes less $151.6 million in cash. The increase compared to the prior year was a result of a decrease in our cash balance due to the repurchase of approximately 18.2 million common shares, for total consideration of $178.8 million. Our next scheduled senior note repayments of US$59.6 million and US$22.0 million are due in May and June 2020, respectively, with remaining maturities extending to 2026. At December 31, 2019, we were undrawn on our US$600 million bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, was 93% for 2019 compared to 84% in 2018. After adjusting for net acquisition and divestment proceeds, our funding surplus for the year ended December 31, 2019 was $36.7 million compared to $104.9 million in 2018.

In 2019, a total of $206.5 million was returned to shareholders through the repurchase of 18.2 million common shares under the NCIB at an average price of $9.80 per share and dividend payments of $27.7 million. In comparison, we returned $108.3 million to shareholders in 2018 through the repurchase of 5.9 million common shares at an average price of $13.33 per share and dividend payments of $29.3 million. We expect to continue to pay monthly dividends to our shareholders of $0.01 per share in 2020; however, if economic conditions change, we may make adjustments. We intend to continue to allocate a portion of our free cash flow to share repurchases in 2020.

Our working capital deficiency, excluding cash and cash equivalents and current derivative assets and liabilities, increased to $210.4 million at December 31, 2019 from $143.1 million at December 31, 2018 due to additional senior note maturities in 2020. We expect to finance our working capital deficit and ongoing working capital requirements through cash, adjusted funds flow and our bank credit facility. In addition, we have sufficient liquidity to meet our financial commitments for the near term, as disclosed under "Commitments" below.

During the fourth quarter, we completed a two year extension of our senior, unsecured, covenant-based bank credit facility, which now matures on October 31, 2023. As part of the extension, we have amended the credit facility to US$600 million from CAD$800 million. There were no significant amendments or additions to the agreement terms or debt covenants. Drawn fees on our bank credit facility range between 125 and 315 basis points over Banker's Acceptance rates, with current drawn fees of 150 basis points over Banker's Acceptance rates based on our current reported senior net debt to adjusted EBITDA ratio. The bank credit facility ranks equally with our senior unsecured covenant-based notes.

At December 31, 2019, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at www.sedar.com.

The following table lists our financial covenants at December 31, 2019:

Covenant Description		December 31, 2019
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA(1)	3.5x	0.9x
Total debt to adjusted EBITDA(1)	4.0x	0.9x
Total debt to capitalization	50%	20%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA(1)(2)	3.0x – 3.5x	0.9x
Senior debt to consolidated present value of total proved reserves(3)	60%	20%
	Minimum Ratio	
Adjusted EBITDA to interest (1)	4.0x	20.7x

Definitions
"Senior Debt" is calculated as the sum of drawn amounts on our bank credit facility, outstanding letters of credit and the principal amount of senior notes.
"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended December 31, 2019 were $173.0 million and $700.7 million, respectively.
"Total Debt" is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.
"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes
(1) See "Non-GAAP Measures" in this MD&A for a reconciliation of adjusted EBITDA to net income.
(2) Senior debt to adjusted EBITDA for the senior notes may increase to 3.5x for a period of 6 months, after which the ratio decreases to 3.0x.
(3) Senior debt to consolidated present value of total proved reserves is calculated annually on December 31 based on before tax reserves at forecast prices discounted at 10%.

Counterparty Credit

OIL AND NATURAL GAS SALES COUNTERPARTIES

Our oil and natural gas receivables are with customers in the oil and gas industry and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. A credit review process is in place to assess and monitor our counterparties' creditworthiness on a regular basis. This process involves reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted, we obtain financial assurances such as letters of credit, parental guarantees or third-party insurance to mitigate a portion of our credit risk. This process is utilized for both our oil and natural gas sales counterparties as well as our financial derivative counterparties.

FINANCIAL DERIVATIVE COUNTERPARTIES

We are exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. We mitigate this risk by entering into transactions with major financial institutions, the majority of which are members of our bank syndicate. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the majority of our financial counterparties. These agreements provide some credit protection by generally allowing parties to aggregate amounts owing to each other under all outstanding transactions and settle with a single net amount in the case of a credit event. To date we have not experienced any losses due to non-performance by our derivative counterparties. All of our derivative counterparties are considered investment grade. At December 31, 2019, we had $10.6 million in mark-to-market assets offset by $2.7 million of mark-to-market liabilities resulting in a net asset position of $7.9 million.

Dividends

($ millions, except per share amounts)	2019	2018	2017
Dividends to shareholders[1]	$ 27.7	$ 29.3	$ 29.0
Per weighted average share (Basic)	$ 0.12	$ 0.12	$ 0.12

(1) Excludes changes in non-cash financing working capital. See Note 18(b) of the Consolidated Financial Statements for additional information.

We reported total dividends of $27.7 million or $0.12 per share to our shareholders in 2019. During 2018 and 2017, we reported total dividends of $29.3 million or $0.12 per share and $29.0 million or $0.12 per share, respectively.

The dividend is part of our strategy to return capital to our shareholders. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	2019	2018	2017
Share capital ($ millions)	$ 3,088.1	$ 3,337.6	$ 3,386.9
Common shares outstanding (thousands)	221,744	239,411	242,129
Weighted average shares outstanding – basic (thousands)	231,334	244,076	241,929
Weighted average shares outstanding – diluted (thousands)	231,334	247,261	247,874

For the twelve months ended December 31, 2019, a total of 1,007,234 units vested pursuant to our treasury settled LTI plans (2018 – 2,539,498; 2017 – 1,646,000). In total, 564,000 common shares were issued from treasury and $4.4 million was transferred from paid-in capital to share capital (2018 – 2,539,498 and $23.4 million; 2017 – 1,646,000 and $21.0 million). We elected to cash settle the remaining units related to the required tax withholdings (2019 – $5.0 million, 2018 – nil; 2017 - nil). During 2019, no common shares were issued pursuant to our stock option plan (2018 – 668,000 common shares for $9.1 million; 2017- nil).

On March 21, 2019, Enerplus renewed its NCIB to continue to repurchase shares through the facilities of the Toronto Stock Exchange (the "TSX"), New York Stock Exchange and/or alternative Canadian trading systems. Pursuant to the NCIB, the Company was permitted to repurchase for cancellation up to 16,673,015 common shares over a period of twelve months commencing on March 26, 2019. All repurchases are made in accordance with the NCIB at prevailing market prices plus brokerage fees, with consideration allocated to share capital up to the average carrying amount of the shares, and any excess is allocated to accumulated deficit. On November 7, 2019, the Company's Board of Directors approved an increase to the maximum number of common shares that may be repurchased under the NCIB to up to 10% of the public float (or an additional 7,145,578 common shares) until the expiry of the NCIB on March 25, 2020. On February 20, 2020, the Company received approval from the Board of Directors to renew the NCIB upon expiry of the existing term on March 25, 2020, subject to approval by the TSX. The proposed renewal is expected to be for 10% of the public float (within the meaning under the TSX rules) consistent with the current bid.

During the twelve months ended December 31, 2019, the Company repurchased 18.2 million common shares under the NCIB at an average price of $9.80 per share for total consideration of $178.8 million (2018 – 5.9 million, $79.0 million; 2017 - nil). Of the amount paid, $253.9 million was charged to share capital and $75.1 million was credited to accumulated deficit (2018 – $82.6 million and $3.6 million; 2017 - nil). Subsequent to year end and up to February 20, 2020, the Company repurchased approximately 0.3 million common shares under the NCIB for total consideration of $2.5 million.

On May 23, 2019, we filed a short form base shelf prospectus (the "Shelf Prospectus") with securities regulatory authorities in each of the provinces of Canada and a Registration Statement with the U.S. Securities Exchange Commission. The Shelf Prospectus allows us to offer and issue up to an aggregate amount of $2.0 billion of common shares, preferred shares, warrants, subscription receipts and units by way of one or more prospectus supplements during the 25-month period that the Shelf Prospectus remains in place.

At February 20, 2020, we had 222,118,267 common shares outstanding. In addition, an aggregate of 6,645,412 common shares may be issued to settle outstanding grants under our share award incentive plan (in the form of PSUs and RSUs), and stock option plan, assuming the maximum payout multiplier of 2.0 times for the PSUs.

For further details see Note 14 to the Financial Statements.

Commitments

We have the following minimum annual commitments:

		Minimum Annual Commitment Each Year					Total Committed
($ millions)	Total	2020	2021	2022	2023	2024	after 2024
Senior notes[1]	$ 606.6	$ 106.0	$ 106.0	$ 130.7	$ 104.7	$ 104.7	$ 54.5
Transportation commitments	313.2	34.8	31.7	29.3	29.0	28.7	159.7
Processing commitments	12.6	3.2	1.5	1.5	1.5	1.5	3.4
Operating lease obligations	58.1	19.4	14.1	7.7	6.7	6.2	4.0
Total commitments[2][3]	$ 990.5	$ 163.4	$ 153.3	$ 169.2	$ 141.9	$ 141.1	$ 221.6

(1) Interest payments have not been included.
(2) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(3) US$ commitments have been converted to CDN$ using the December 31, 2019 foreign exchange rate of 1.30.

In the Marcellus, we have firm transportation agreements in place for approximately 66,000 Mcf/day of natural gas, which expire between 2020 and 2036. This includes an agreement for firm pipeline capacity on the Tennessee Gas Pipeline from our Marcellus producing region to downstream connections for 30,000 Mcf/day of natural gas until mid-2027, reducing to 15,000 Mcf/day for an additional 9 years, with a total estimated transportation commitment of US$83.5 million through 2036. In the Bakken region, we hold firm pipeline capacity to transport a portion of our crude oil production to the U.S. Gulf Coast, which expires in early 2029.

In Canada, we have various firm transportation agreements for approximately 2,400 BOE/day of our crude oil and natural gas liquids production in 2020, decreasing to approximately 960 BOE/day on average from 2021 to 2027. We also have firm natural gas transportation contracts in 2020 for approximately 34,000 Mcf/day. At December 31, 2019, we have firm natural gas liquids fractionation contracts for 1,100 bbls/day through 2027.

Our commitments and contingencies are more fully described in Note 16 to the Financial Statements. Our operating lease obligations are detailed in Note 9 to the Financial Statements.

SELECTED ANNUAL CANADIAN AND U.S. FINANCIAL RESULTS

	Year ended December 31, 2019			Year ended December 31, 2018		
(millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	8,625	41,079	49,704	9,282	36,142	45,424
Natural gas liquids (bbls/day)	895	4,034	4,929	1,064	3,422	4,486
Natural gas (Mcf/day)	23,706	254,745	278,451	27,497	232,340	259,837
Total average daily production (BOE/day)	13,471	87,571	101,042	14,929	78,287	93,216
Pricing(2)						
Crude oil (per bbl)	$ 59.71	$ 70.92	$ 68.98	$ 55.50	$ 79.49	$ 74.59
Natural gas liquids (per bbl)	28.82	12.16	15.19	45.22	23.05	28.31
Natural gas (per Mcf)	2.42	2.91	2.87	2.90	3.49	3.42
Capital Expenditures						
Capital spending	$ 37.9	$ 581.0	$ 618.9	$ 53.3	$ 540.6	$ 593.9
Acquisitions	6.0	18.4	24.4	4.2	21.6	25.8
Divestments	(9.0)	(0.6)	(9.6)	1.2	(8.1)	(6.9)
Netback(3) Before Hedging						
Oil and natural gas sales	$ 220.8	$ 1,352.1	$ 1,572.9	$ 237.9	$ 1,373.0	$ 1,610.9
Royalties	(43.5)	(274.6)	(318.1)	(39.6)	(278.6)	(318.2)
Production taxes	(2.6)	(80.5)	(83.1)	(3.1)	(84.2)	(87.3)
Cash operating expenses	(72.1)	(218.7)	(290.8)	(75.2)	(163.1)	(238.3)
Transportation costs	(10.1)	(134.8)	(144.9)	(11.4)	(112.1)	(123.5)
Netback before hedging	$ 92.5	$ 643.5	$ 736.0	$ 108.6	$ 735.0	$ 843.6
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 66.1	$ —	$ 66.1	$ (88.2)	$ —	$ (88.2)
General and administrative expense(4)	29.0	43.8	72.8	43.3	32.5	75.8
Goodwill Impairment	451.1	—	451.1	—	—	—
Current income tax expense/(recovery)	(13.9)	(19.5)	(33.4)	(0.4)	(26.7)	(27.1)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See “Non-GAAP Measures” section in this MD&A.
(4) Includes share-based compensation.

THREE YEAR SUMMARY OF KEY MEASURES

($ millions, except per share amounts)	2019	2018	2017
Oil and natural gas sales, net of royalties	$ 1,254.8	$ 1,292.7	$ 920.7
Net income/(loss)	(259.7)	378.3	237.0
Per share (Basic)	(1.12)	1.55	0.98
Per share (Diluted)	(1.12)	1.53	0.96
Adjusted net income(1)	243.2	344.8	132.2
Cash flow from operating activities	694.2	738.8	476.1
Adjusted funds flow(1)	709.0	753.5	524.1
Cash dividends(2)	27.7	29.3	29.0
Per share (Basic)(2)	0.12	0.12	0.12
Total assets	2,565.8	3,118.3	2,645.8
Total debt	606.6	696.8	672.4
Total debt net of cash(1)	455.0	333.5	325.8

(1) See “Non-GAAP Measures” section of this MD&A.
(2) Calculated based on dividends paid or payable.

2019 versus 2018

Oil and natural gas sales, net of royalties, were $1,254.8 million in 2019 compared to $1,292.7 million in 2018, with the impact of higher production more than offset by lower commodity prices.

We reported a net loss of $259.7 million in 2019 compared to net income of $378.3 million in 2018. The decrease in 2019 was primarily due to a $451.1 million non-cash Canadian goodwill impairment, along with losses on commodity derivative instruments.

Cash flow from operations and adjusted funds flow decreased to $694.2 million and $709.0 million, respectively, from $738.8 million and $753.5 million, respectively, in 2018. Oil and natural gas sales decreased due to lower realized commodity prices, while operating expenses increased over the same period, in part due to higher liquids volumes. These decreases were offset by realized commodity derivative gains in 2019 compared to losses in 2018.

2018 versus 2017

Oil and natural gas sales, net of royalties, were $1,292.7 million in 2018 compared to $920.7 million in 2017 due to higher realized commodity prices, increased production and higher crude oil and natural gas liquids weighting in 2018.

We reported net income of $378.3 million in 2018 compared to $237.0 million in 2017. The increase in 2018 was primarily due to increased oil and natural gas sales and higher gains on commodity derivative instruments, which were offset in part by no gains on asset divestments and increased foreign exchange losses compared to 2017.

Cash flow from operating activities and adjusted funds flow increased to $738.8 million and $753.5 million, respectively, in 2018 from $476.1 million and $524.1 million in 2017. The increase was mainly due to a $372.0 million increase in net oil and gas natural gas sales, offset by realized losses on derivative instruments and higher operating expenses and production taxes resulting from higher production.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2019				
Fourth Quarter	$ 327.0	$ (429.1)	$ (1.93)	$ (1.93)
Third Quarter	318.9	65.1	0.28	0.28
Second Quarter	321.4	85.1	0.36	0.36
First Quarter	287.5	19.2	0.08	0.08
Total 2019	$ 1,254.8	$ (259.7)	$ (1.12)	$ (1.12)
2018				
Fourth Quarter	$ 326.7	$ 249.4	$ 1.03	$ 1.02
Third Quarter	373.6	86.9	0.35	0.35
Second Quarter	327.4	12.4	0.05	0.05
First Quarter	265.0	29.6	0.12	0.12
Total 2018	$ 1,292.7	$ 378.3	$ 1.55	$ 1.53

Oil and natural gas sales, net of royalties, decreased in 2019 compared to 2018 due to lower realized commodity prices, partially offset by increased production. We reported a net loss in 2019 due to a non-cash impairment of $451.1 million on our Canadian goodwill asset recorded in the fourth quarter and a loss on commodity derivative instruments of $66.1 million compared to a gain of $88.2 million recorded in 2018.

During 2018, we reported oil and gas sales, net of royalties, of $1,292.7 million. Although production levels increased throughout 2018, declining commodity prices during the fourth quarter of 2018 resulted in lower net sales. Net income was $378.3 million in 2018, largely due to higher oil and gas sales, net of royalties, compared to 2017 and non-cash gains on commodity derivatives as commodity prices fell during the fourth quarter.

ENVIRONMENT, SOCIAL AND GOVERNANCE ("ESG")

Enerplus believes that minimizing the environmental impacts of its operations is a foundational tenet of corporate responsibility. Moreover, as the global economy transitions to a lower carbon future, climate related policies and regulations around carbon emissions are becoming increasingly stringent, requiring businesses to adapt to support long-term business resilience. We intend to continue to improve energy efficiencies and proactively manage our environmental impact in compliance with applicable government regulations, including regulations enacted at the provincial, state and federal jurisdictions in which we operate.

Our Board of Directors are responsible for overseeing our ESG initiatives. Specific accountability for our six material focus areas have been mapped to the relevant Board subcommittees, including the Compensation and Human Resources Committee, the Safety and Social Responsibility Committee (the "S&SR Committee") and the Corporate Governance and Nominating Committee. The six material focus areas are:

- Greenhouse Gas ("GHG") Emissions
- Water Management
- Corporate Culture
- Stakeholder Engagement
- Health & Safety
- Board Expertise & Engagement

As part of our continued integration of ESG issues into our strategy and operations, we have established targets for reducing GHG emissions intensity and freshwater use. Using 2019 as a baseline, we are targeting a 10% reduction of our GHG emissions per BOE in 2020. Through operational efficiency, we expect to reduce levels of flared natural gas in North Dakota in 2020 which is projected to help us reach our GHG emissions intensity reduction target. We are evaluating additional operational changes and aim to identify technologies and opportunities to achieve further emissions intensity reductions beyond 2020. Enerplus' 2020 target addresses scope 1 and scope 2 emissions from its operations.

The vast majority (approximately 80% in 2018) of the water used in our operations is reused. We aim to further improve our water management and have established a target to reduce our freshwater use per well completion in North Dakota by 15%, on average, in 2020 compared to 2019 by reusing produced water in our fracturing operations.

We have a Safety and Social Responsibility Policy ("S&SR Policy"), which articulates our commitment to health and safety, stakeholder engagement, environmental and regulatory compliance. Our Board of Directors and President & Chief Executive Officer are ultimately accountable for ensuring compliance with the S&SR Policy. The S&SR Committee of our Board of Directors is responsible for overseeing our S&SR performance, ensuring there are adequate systems in place to support ongoing compliance, and to plan the Company's activities in a safe and socially responsible manner.

The S&SR Committee regularly reviews health, safety, environmental and regulatory updates, and risks. At present, we believe we are, and expect to continue to be, in compliance with all material applicable environmental laws and regulations and we have included appropriate amounts in our capital expenditure budget to continue to meet our ongoing environmental obligations. However, increased capital and operating costs may be incurred if regulations in Canada or the U.S. impose more stringent compliance requirements.

Annually, we publish a Corporate Sustainability Report in accordance with the Global Reporting Initiative (GRI) international standard and in 2019 we expanded our report to include additional disclosure pertaining to the Sustainability Accounting Standards Boards (SASB) materiality metrics. The report summarizes our environmental, safety, social responsibility and governance performance, and can be found on our website at www.enerplus.com.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with U.S. GAAP requires management to make certain judgments and estimates. Due to the timing of when activities occur compared to the reporting of those activities, management must estimate and accrue operating results and capital spending. Changes in these judgments and estimates could have a material impact on our financial results and financial condition.

Oil and Natural Gas Properties and Reserves

Enerplus follows the full cost method of accounting for oil and natural gas properties. The process of estimating reserves is critical in determining several accounting estimates including the Company's depletion, ceiling test, goodwill impairment, valuation allowance on deferred income tax and gain or loss calculations. Estimating reserves requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and natural gas prices, operating costs and royalty burdens change. Reserves estimates impact net income through depletion, the determination of asset retirement obligation and the application of impairment tests. Revisions or changes in reserves estimates can have either a positive or a negative impact on net income.

Asset Impairment

Ceiling Test

Under the full cost method of accounting for PP&E, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and natural gas properties that can be capitalized on our balance sheet by cost centre. If the net capitalized costs of our oil and natural gas properties exceed the cost centre ceiling, we are subject to a ceiling test write-down to the extent of such excess. These write-downs reduce net income and impact shareholders' equity in the period of occurrence and result in lower depletion expense in future periods. The volume and discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and natural gas that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average oil and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that further write-downs of our oil and natural gas properties could occur in the future. Under U.S. GAAP impairments are not reversed in future periods.

Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net assets acquired. Goodwill is allocated to reporting units and is assessed for impairment at least annually. To assess impairment, the Company first evaluates qualitative factors, such as industry and market considerations and overall financial performance, to determine whether events or changes in circumstances indicate that goodwill may be impaired. If it is more likely than not that the fair value of the reporting unit is less than its carrying value including goodwill, a quantitative impairment test is performed. If the carrying amount of the reporting unit exceeds its related fair value, goodwill is written down to its implied fair value. The fair value used in the impairment test is based on estimates of discounted future cash flows which involve assumptions of natural gas and liquids reserves, including commodity prices, future costs and discount rates.

Income Taxes

Management makes certain estimates in calculating deferred tax assets and liabilities, as well as income tax expense. These estimates often involve judgment regarding differences in the timing and recognition of revenue and expense for tax and financial reporting purposes as well as the tax basis of our assets and liabilities at the balance sheet date before tax returns are completed. Additionally, we must assess the likelihood we will be able to recover or utilize our deferred tax assets. We must record a valuation allowance against a deferred tax asset where all or a portion of that asset is not expected to be realized. In evaluating whether a valuation allowance should be applied, we consider evidence such as future taxable income, among other factors, both positive and negative. This determination involves numerous judgments and assumptions and includes estimating factors such as commodity prices, production and other operating conditions. If any of those factors, assumptions or judgments change, the deferred tax asset could change, and in particular decrease in a period where we determine it is more likely than not that the asset will not be realized. Alternatively, a valuation allowance may be reversed where it is determined it is more likely than not that the asset will be realized.

Asset Retirement Obligation

Management calculates the asset retirement obligation based on estimated costs to abandon, reclaim and remediate its ownership interest in all wells, facilities and pipelines and the estimated timing of the costs to be incurred in future periods. The fair value estimate is capitalized to PP&E as part of the cost of the related asset and depleted over its useful life. There are uncertainties related to asset retirement obligations and the impact on the financial statements could be material as the eventual timing and costs for the obligations could differ from our estimates. Factors that could cause our estimates to differ include any changes to laws or regulations, reserves estimates, costs and technology.

Business Combinations

Management makes various assumptions in determining the fair value of any acquired company's assets and liabilities in a business combination. The most significant assumptions and judgments made relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we, and independent evaluators, estimate oil and gas reserves and future prices of crude oil and natural gas.

Derivative Financial Instruments

We utilize derivative financial instruments to manage our exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Fair values of derivative contracts fluctuate depending on the underlying estimate of future commodity prices, foreign currency exchange rates, interest rates and counterparty credit risk.

RECENT U.S. GAAP ACCOUNTING AND RELATED PRONOUNCEMENTS

Enerplus adopted ASC 842 *Leases* effective January 1, 2019 using the modified retrospective method, with ASC 842 applied to all contracts not yet completed as of the date of adoption with the cumulative effect on comparative periods reflected as an adjustment to retained earnings, if applicable. The most significant impact was the recognition of ROU assets and lease liabilities for operating leases, while accounting for finance leases and lessor accounting remained unchanged.

Enerplus elected the practical expedient related to land easements, allowing it to carry forward its accounting treatment for land easements on existing agreements.

The impacts of the adoption of ASC 842 as at January 1, 2019 are as follows:

($ thousands)	As reported as at December 31, 2018	Adjustments	Balance as at January 1, 2019
Right-of-use assets	$ —	$ 50,193	$ 50,193
Current portion of lease liabilities	—	(10,648)	(10,648)
Lease liabilities	—	(39,545)	(39,545)
Total	$ —	$ —	$ —

The standard did not materially impact the Company's Consolidated Statement of Income/(Loss) or Consolidated Statements of Cash Flows.

Refer to Note 2(p) in our Financial Statements for a detailed listing of Standards and Interpretations that were issued but not yet effective at December 31, 2019.

RISK FACTORS AND RISK MANAGEMENT

Commodity Price Risk

Our operating results and financial condition are dependent on the prices we receive for our crude oil, natural gas liquids, and natural gas production. These prices have fluctuated widely in response to a variety of factors including global and domestic supply and demand of crude oil, natural gas and natural gas liquids, economic conditions including currency fluctuations, global gross domestic product growth, weather conditions, the level of consumer demand, the ability to export oil and liquefied natural gas and natural gas liquids from North America and the supply and price of imported oil and liquefied natural gas, the production and storage levels of North American crude oil, natural gas and natural gas liquids, political stability, transportation facilities, availability of processing, fractionation and refining facilities, the effect of world-wide energy conservation and greenhouse gas reduction measures, the price and availability of alternative fuels and existing and proposed changes to government regulations.

A future decline in crude oil or natural gas prices may have a material adverse effect on our operations and cash flows, financial condition, borrowing ability, levels of reserves and resources and the level of expenditures for the development of our oil and natural gas reserves or resources. Certain oil or natural gas wells may become or remain uneconomic to produce if commodity prices are low, thereby impacting our production volumes, or our desire to market our production in unsatisfactory market conditions. Furthermore, we may be subject to the decisions of third party operators or to legislative decisions by regional governments who, independently and using different economic parameters, may decide to curtail or shut-in jointly owned production or to mandate industry-wide production curtailments.

We may use financial derivative instruments and other hedging mechanisms to help limit the adverse effects of crude oil, natural gas liquids, and natural gas price volatility. However, we do not hedge all of our production and expect there will always be a portion that remains unhedged. Furthermore, we may use financial derivative instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, we may forego the benefits that would otherwise be experienced if commodity prices increase. At February 20, 2020, approximately 61% of our 2020 forecasted crude oil production, net of royalties, are hedged at price levels disclosed in the "Price Risk Management" section above. Refer to the "Price Risk Management" section for further details on our price risk management program.

Regulatory Risk and Greenhouse Gas Emissions

Government royalties, environmental laws and regulatory requirements can have a significant financial and operational impact on us. As an oil and gas producer, we operate under federal, provincial, state, tribal and municipal legislation and regulation that govern such matters as royalties, land tenure, prices, production rates, various environmental protection controls, well and facility design and operation, income taxes, and the exportation of crude oil, natural gas and other products. We may be required to apply for regulatory approvals in the ordinary course of business. To the extent that we fail to comply with applicable government regulations or regulatory approvals, we may be subject to compliance and enforcement actions that are either remedial or punitive to deter future noncompliance. Such actions include fines or fees, notices of noncompliance, warnings, orders, curtailment, administrative sanctions, and prosecution.

Government regulations may be changed from time to time in response to economic or political conditions, including the election of new state, provincial or federal leaders. Additionally, our entry into new jurisdictions or adoption of new technology may attract additional regulatory oversight which could result in higher costs or require changes to proposed operations. Canadian and U.S. governments have enhanced their oversight and reporting obligations associated with fracturing procedures and increased their scrutiny of the usage and disposal of chemicals and water used in fracturing procedures. Additionally, various levels of Canadian and U.S. governments are considering or have implemented legislation to reduce emissions of greenhouse gases, including volatile organic compounds ("VOC"), and methane gas emissions.

The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations could negatively impact the development of oil and gas properties and assets, reduce demand for crude oil and natural gas or impose increased costs on oil and gas companies including taxes, fees or other penalties.

Although we have no control over these regulatory risks, we continuously monitor changes in these areas by participating in industry organizations, conferences, exchanging information with third party experts and employing qualified individuals to assess the impact of such changes on our financial and operating results. Accordingly, while we continue to prepare to meet the potential requirements at each of the provincial, state and federal levels, the actual cost impact and its materiality to our business remains uncertain.

Risks Relating to Climate Change

Enerplus is subject to climate change related risks, which are generally grouped into two categories: physical risks and transition risks. Physical risks include the impact that a change in climate could have on our operations, including limited water availability, severe weather or fire. These events may increase the cost of water, energy, insurance or capital projects, impacting our profitability. The physical risks of climate change may also result in operational delays, depending on the nature of the event. Enerplus does not believe that its current or near-term operations expose it to any particular physical risks which differ from those facing a typical North American onshore oil and gas producer, and currently cannot predict or quantify the potential financial impact of any such risks.

Transition risk is broader and relates to the consequences of a global transition to reduced carbon, including the risk of regulatory and policy change and reputational concerns. Concerns over climate change may result in additional or more stringent legislation. Such changes could impose higher standards or require significant reductions to GHG emissions or setback requirements for facilities and wells, which could result in significant penalties for failure to comply, or increased capital expenditures, operating expenses, abandonment and reclamation obligations and distribution costs or the loss of operating licenses. There is also a reputational risk associated with climate change, which considers the public perception of Enerplus' role in the transition to a low carbon economy. We seek to mitigate this risk through a strong ESG program with six material focus areas, which are overseen by the Company's Board of Directors and applicable Board subcommittees. Our strategy is to be a "best in basin" operator – in the eyes of our shareholders, employees, contractors, regulators, communities and the general public. Despite these efforts, activities undertaken directly by Enerplus or its employees, or by others in industry, could adversely affect Enerplus' reputation. If the reputation of the Corporation, or the oil and gas industry in general, is diminished, it could result in: the loss of employees, or revenue; delays in regulatory approvals; increased operating, capital, financing and regulatory costs; reduced shareholder confidence and negative stock price movement.

Access to Transportation and Processing Capacity

Market access for crude oil, natural gas liquids and natural gas production in Canada and the U.S. is dependent on our ability, and the ability of our buyers as applicable, to obtain transportation capacity on third party pipelines and rail as well as access to processing facilities. As production increases in the regions where we operate, it is possible production may exceed the existing capacity of the gathering, pipeline, processing or rail infrastructure. While third party pipelines, processors and independent rail operators generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of capacity. There are occasionally operational reasons for curtailing transportation and processing capacity. Accordingly, there can be periods where transportation and processing capacity is insufficient to accommodate all the production from a given region, causing added expense and/or volume curtailments for all shippers. Our assets are concentrated in specific regions where government or other third parties could limit or ban the shipping of commodities by truck, pipeline or rail. Special interest groups could also oppose infrastructure development and/or expansion resulting in a delay or even the cancellation of the required infrastructure, further impeding our ability to produce and market our products. Additionally, the transportation of crude oil by rail has been under closer scrutiny by government regulatory agencies in Canada and the U.S. over the past few years. As a result, transporting crude oil by rail may carry a higher cost versus traditional pipeline infrastructure or other means of transporting production.

We monitor this risk for both the short and longer term through dialogue and review with the third party pipelines and other market participants. Where available and commercially appropriate, given the production profile and commodity, we attempt to mitigate transportation and processing risk by contracting for firm pipeline or processing capacity or using other means of transportation, including trucking or selling to third parties that have access to pipeline or rail capacity.

Risk of Increased Capital or Operating Costs

Higher capital or operating costs associated with our operations will directly impact our capital efficiencies and cash flow. Capital costs of completions, specifically the costs of proppant, pumper services, and operating costs such as electricity, chemicals, gas processing, supplies, energy services and labour costs, are a few of the costs that are susceptible to material fluctuation. Although we have a portion of our current capital and operating costs protected with existing agreements, changing regulatory conditions, such as those in the U.S. requiring certain raw materials, such as steel, for use in U.S. businesses to be sourced from the U.S., or that goods and/or services be procured from specific vendors or classes of vendors, may result in higher than expected supply costs for the company.

Risk of Curtailed or Shut-in Production

Should we be required to curtail or shut-in production as a result of low commodity prices, environmental regulation, government regulation or third party operational practices, it could result in a reduction to cash flow and production levels and may result in additional operating and capital costs for the well to achieve prior production levels. In addition, curtailments or shut-ins may cause damage to the reservoir and may prevent us from achieving production and operating levels that were in place prior to the curtailment or shutting-in of the reservoir. Combined with the ongoing volatility in commodity prices, any shortage in pipeline infrastructure in producing regions where we operate may result in discounted prices and an ongoing risk of price-related production curtailments.

Production Replacement Risk

Oil and natural gas reserves naturally deplete as they are produced over time. Our ability to replace production depends on our success in acquiring new land, reserves and/or resources and developing existing reserves and resources. Acquisitions of oil and gas assets will depend on our assessment of value at the time of acquisition and ability to secure the acquisitions generally through a competitive bid process.

Acquisitions and our development capital program are subject to investment guidelines, due diligence and review. Major acquisitions and our annual capital development budget are approved by the Board of Directors and where appropriate, independent reserve engineer evaluations are obtained.

Oil and Gas Reserves and Resources Risk

The value of our company is based on, among other things, the underlying value of our oil and gas reserves and resources. Geological and operational risks along with product price forecasts can affect the quantity and quality of reserves and resources and the cost of ultimately recovering those reserves and resources. Lower crude oil, natural gas liquids, and natural gas prices along with lower development capital spending associated with certain projects may increase the risk of write-downs for our oil and gas property investments. Changes in reporting methodology as well as regulatory practices can result in reserves or resources write-downs.

Each year, independent reserves engineers evaluate the majority of our proved and probable reserves as well as evaluate or audit the resources attributable to a significant portion of our undeveloped land. All reserves information, including our U.S. reserves, has been prepared in accordance with NI 51-101 standards. For U.S. GAAP accounting purposes, our proved reserves are estimated to be technically the same as our proved reserves prepared under NI 51-101 and have been adjusted for the effects of SEC constant prices. Independent reserves evaluations have been conducted on approximately 97% of the total proved plus probable net present value (discounted at 10% and using NI 51-101 standards) of our reserves at December 31, 2019. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 78% of our Canadian reserves and reviewed the internal evaluation completed by Enerplus on the remaining portion. McDaniel also evaluated 100% of the reserves associated with our U.S. tight oil assets. Netherland, Sewell & Associates, Inc. ("NSAI") evaluated 100% of our U.S. Marcellus shale gas assets.

The evaluations of best estimate development pending contingent resources associated with a portion of our Canadian waterflood properties and our North Dakota assets were conducted by Enerplus' qualified reserves evaluators and audited by McDaniel. NSAI evaluated our Marcellus shale gas best estimate development pending contingent resources.

The Reserves Committee of the Board of Directors and the Board of Directors has reviewed and approved the reserves and resources reports of the independent evaluators.

Access to Field Services

Our ability to drill, complete and tie-in wells in a timely manner may be impacted by our access to service providers and supplies. Activity levels in each area may limit our access to these resources, restricting our ability to execute our capital plans in a timely manner. In addition, field service costs are influenced by market conditions and therefore can become cost prohibitive.

Although we have entered into service contracts for a portion of field services that will secure some of our drilling and fracturing services through 2020, access to field services and supplies in other areas of our business will continue to be subject to market availability.

Risk of Impairment of Oil and Gas Properties, Deferred Tax Assets and Goodwill

Under U.S. GAAP, the net capitalized cost of oil and gas properties, net of deferred income taxes, is limited to the present value of after-tax future net revenue from proved reserves, discounted at 10%, and based on the unweighted average of the closing prices for the applicable commodity on the first day of the twelve months preceding the issuer's reporting date. The amount by which the net capitalized costs exceed the discounted value will be charged to net income.

Under U.S. GAAP, the net deferred tax asset is limited to the estimate of future taxable income resulting from existing properties. We estimate future taxable income based on before-tax future net revenue from proved plus probable reserves, undiscounted, using forecast prices, and adjusted for other significant items affecting taxable income. The amount by which the gross deferred tax assets exceed the estimate of future taxable income will be charged to net income, however these amounts can be reversed in future periods if future taxable income increases.

Goodwill is tested for impairment on an annual basis or more frequently if events or changes in circumstances indicate that goodwill may be impaired. We first perform a qualitative assessment by evaluating potential indicators of impairment, and if it is more likely than not that the fair value of the reporting unit is less than its carrying value, a quantitative impairment test is performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to net income.

We recorded no impairment on our crude oil and natural gas assets in 2019, 2018 and 2017. We recorded an impairment of $451.1 million on our Canadian goodwill in 2019. No impairment was recognized on our goodwill in 2018 or 2017. In 2019, we recorded a valuation allowance of $13.9 million against a portion of our Canadian deferred income tax asset due to lower projected future taxable income in Canada. No valuation allowance was recorded against our U.S. deferred income tax asset. There is a risk of impairment on our oil and gas properties, deferred tax asset and goodwill if commodity prices weaken, costs increase, or if there is a downward revision to reserves. Please refer to the "Impairments" and "Income Taxes" sections of the MD&A and Notes 5 and 13 of the Financial Statements for further details.

Counterparty and Joint Venture Credit Exposure

We are subject to the risk that the counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements as a result of liquidity requirements or insolvency. Low oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure of our counterparties to perform their financial or operational obligations may adversely affect our operations and financial position. In addition to the usual delays in payment by purchasers of crude oil and natural gas, payments may also be delayed by, among other things: (i) capital or liquidity constraints experienced by our counterparties, including restrictions imposed by lenders; (ii) accounting delays or adjustments for prior periods; (iii) delays in the sale or delivery of products or delays in the connection of wells to a gathering system; (iv) weather related delays, such as freeze-offs, flooding and premature thawing; (v) blow-outs or other accidents; or (vi) recovery by the operator of expenses incurred in the operation of the properties or the establishment by the operator of reserves for these expenses. Any of these delays could reduce the amount of our cash flow and the payment of cash dividends to our shareholders in a given period and expose us to additional third-party credit risks.

A credit review process is in place to assess and monitor our counterparties' credit worthiness on a regular basis. This includes reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted we attempt to obtain financial assurances such as letters of credit, parental guarantees, or third-party insurance to mitigate our counterparty risk. In addition, we monitor our receivables against a watch list of publicly traded companies that have high debt-to-cash flow ratios or fully drawn bank facilities and, where possible, take our production in kind rather than relying on third party operators. In certain instances, we may be able to aggregate all amounts owing to each other and settle with a single net amount.

See the "Liquidity and Capital Resources" section for further information.

Changes in Income Tax and Other Laws

Income tax, other laws or government incentive programs relating to the oil and gas industry may change in a manner that adversely affects us or our security holders. Canadian, U.S. and foreign tax authorities may interpret applicable tax laws, tax treaties or administrative positions differently than we do or may disagree with how we calculate our income for tax purposes in a manner which is detrimental to us and our security holders.

We monitor developments with respect to pending legal changes and work with the industry and professional groups to ensure that our concerns with any changes are made known to various government agencies. We obtain confirmation from independent legal counsel and advisors with respect to the interpretation and reporting of material transactions.

Cyber Security Risks

We are subject to a variety of information technology and system risks as part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach and destruction or interruption of our information technology systems by third parties or insiders. Although we have security measures and controls in place that are designed to mitigate these risks, a breach of our security and/or a loss of information could occur and result in a loss of material and confidential information, reputation damage, a breach in privacy laws and disruption to business activities. The significance of any such event is difficult to quantify, but may be material in certain circumstances and could have a material effect on our business, financial condition and results of operations.

Anticipated Benefits of Acquisitions or Divestments

From time to time, we may acquire additional crude oil and natural gas properties and related assets. Achieving the anticipated benefits of such acquisitions will depend in part on successfully consolidating functions and integrating operations, procedures, and personnel in a timely and efficient manner, as well as our ability to realize the anticipated growth opportunities from combining and integrating the acquired assets and properties into our existing business. These activities will require the dedication of substantial management effort, time, capital, and other resources, which may divert management's focus, capital and other resources from other strategic opportunities and operational matters during this process. The risk factors specified in this MD&A relating to the crude oil and natural gas business and our operations, reserves and resources apply equally to future properties or assets that we may acquire. We conduct due diligence in connection with acquisitions, but there is no assurance that we will identify all the potential risks and liabilities related to such properties.

When acquiring assets, we are subject to inherent risks associated with predicting the future performance of those assets. We may make certain estimates and assumptions respecting the characteristics of the assets we acquire, that may not be realized over time. As such, assets acquired may not possess the value we attribute to them, which could adversely impact our future cash flows. To the extent that we make acquisitions with higher growth potential, the higher risks often associated may result in increased chances that actual results may vary from our initial estimates. An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods, approaches, and assumptions than those of our engineers, and these initial assessments may differ significantly from our subsequent assessments. There is also no assurance that the acquired assets will be viewed favourably by our investors and could result in a negative effect to the price of our common shares.

Certain acquisitions, and in particular acquisitions of higher risk/higher growth assets and the development of those acquired assets, may require capital expenditures and we may not receive cash flow from operating activities from these acquisitions for several years, or in amounts less than anticipated. Accordingly, the timing and amount of capital expenditures may adversely affect our cash flow.

We may also seek to divest of properties and assets from time to time. These divestments may consist of non-core properties or assets, or may consist of assets or properties that are being monetized to fund alternative projects or development or debt repayments. There can be no assurance that we will be successful, that we will realize the amount of desired proceeds, or that such divestments will be viewed positively by the financial markets. Divestments may negatively affect our results of operations or the trading price of our common shares. In addition, although divestments typically transfer future obligations to the buyer, we may not be exempt from certain future obligations, including abandonment, reclamation, and/or remediation if applicable, which may have an adverse effect on our operations and financial condition.

Access to Capital Markets

Our access to capital has allowed us to fund a portion of our acquisitions and development capital program through issuance of equity and debt in past years. Continued access to capital is dependent on our ability to optimize our existing assets and to demonstrate the advantages of the acquisition or development program that we are financing at the time, as well as investors' view of the oil and gas industry overall. We may not be able to access the capital markets in the future on terms favorable to us, or at all. Our continued access to capital markets is dependent on corporate performance and investor perception of future performance (both corporately and for the oil and gas sector in general).

We are required to assess our "foreign private issuer" status under U.S. securities laws on an annual basis. If we were to lose our status as a "foreign private issuer" under U.S. securities laws, we may have restricted access to capital markets for a period of time until the required approvals are in place from the SEC.

Ability to Divest Properties

Recent regulatory changes in Alberta and Saskatchewan have increased the minimum corporate liability rating required of purchasers of crude oil and natural gas properties. As a result, the potential number of parties able to acquire our non-core assets has been reduced, we may not be able to obtain full value for such assets, or transactions may involve greater risk and complexity. The Supreme Court of Canada's decision in the Redwater Energy Corporation case may also impact our ability to transfer licenses, approvals or permits, and may result in increased costs and delays or require changes to our abandonment of projects and transactions. We also understand that further regulatory changes are being planned in Alberta and British Columbia, which may result in additional factors being considered when evaluating such transactions.

Title Defects or Litigation

Unforeseen title defects or litigation may result in a loss of entitlement to production, reserves and resources.

Although we conduct title reviews prior to the purchase of assets these reviews do not guarantee that an unforeseen defect in the chain of title will not arise. We maintain good working relationships with our industry partners; however, disputes may arise from time to time with respect to ownership of rights of certain properties or resources.

Foreign Currency Exposure

We have exposure to fluctuations in foreign currency as all of our senior notes are denominated in U.S. dollars. Our U.S. operations are directly exposed to fluctuations in the U.S. dollar when translated to our Canadian dollar denominated financial statements. We also have indirect exposure to fluctuations in foreign currency as our crude oil sales and a portion of our natural gas sales are based on U.S. dollar indices. Our oil and gas revenues are positively impacted when the Canadian dollar weakens relative to the U.S. dollar. However, our U.S. capital spending, transportation and operating costs, interest expense and U.S. dollar denominated debt are negatively impacted with a weak Canadian dollar.

Currently, we do not have any foreign exchange contracts in place to hedge our foreign exchange exposure. However, we continue to monitor fluctuations in foreign exchange and the impact on our operations.

Interest Rate Exposure

Movements in interest rates and credit markets may affect our borrowing costs and value of investments such as our shares as well as other equity investments.

Currently, we do not have any floating interest rate debt. At December 31, 2019, we were undrawn on our US$600 million bank credit facility and our debt consisted of fixed interest rate senior notes.

ADJUSTED FUNDS FLOW SENSITIVITY

The sensitivities below reflect all commodity contracts listed in Note 15 to the Financial Statements and are based on 2020 guidance price levels of: WTI - US$55.00/bbl, NYMEX - US$2.25/Mcf and a USD/CDN exchange rate of 1.30. To the extent crude oil and natural gas prices change significantly from current levels, the sensitivities will no longer be relevant.

Sensitivity Table	Estimated Effect on 2020 Adjusted Funds Flow per Share[1]
Increase of US$5.00 per barrel in the price of WTI crude oil	$ 0.32
Decrease of US$5.00 per barrel in the price of WTI crude oil	$ (0.20)
Change of US$0.50 per Mcf in the price of NYMEX natural gas	$ 0.19
Change of 1,000 BOE/day in production	$ 0.05
Change of $0.01 in the USD/CDN exchange rate	$ 0.03
Change of 1% in interest rate[2]	$ nil

(1) Calculated using 221.7 million shares outstanding at December 31, 2019.

(2) There is no impact to adjusted funds flow for an increase in interest rates, as Enerplus is currently undrawn on its floating interest rate bank credit facility and all outstanding senior notes are based on fixed interest rates.

2020 GUIDANCE

A summary of our previously released 2020 guidance is below.

Summary of 2020 Expectations	Target
Capital spending	$520 - $570 million
Average annual production	96,000 – 100,000 BOE/day
Average annual crude oil and natural gas liquids production	57,000 – 60,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	26.0%
Operating expenses	$8.50/BOE
Transportation costs	$4.00/BOE
Cash G&A expenses	$1.50/BOE

2020 Differential/Basis Outlook[1]	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(5.00)/bbl
Average Marcellus natural gas differential (compared to NYMEX natural gas)	US$(0.45)/Mcf

(1) Excludes transportation costs.

NON-GAAP MEASURES

The Company utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and therefore may not be comparable with the calculation of similar measures by other entities:

"Netback" is used by Enerplus and is useful to investors and securities analysts in evaluating operating performance of our crude oil and natural gas assets. Netback is calculated as oil and natural gas sales less royalties, production taxes, cash operating expenses and transportation costs.

Calculation of Netback	**Year ended December 31,**		
($ millions)	**2019**	**2018**	**2017**
Oil and natural gas sales, net of royalties	$ 1,254.8	$ 1,292.7	$ 920.7
Less:			
Production taxes	(83.1)	(87.3)	(54.3)
Cash operating expenses[(1)]	(290.8)	(238.3)	(197.7)
Transportation costs	(144.9)	(123.5)	(111.3)
Netback before hedging	$ 736.0	$ 843.6	$ 557.4
Cash gains/(losses) on derivative instruments	15.4	(35.8)	8.6
Netback after hedging	$ 751.4	$ 807.8	$ 566.0

(1) Cash operating expenses have been adjusted to exclude non-cash gains of nil in 2019, nil in 2018 and $0.6 million in 2017.

"Adjusted funds flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating and financial performance, leverage and liquidity. Adjusted funds flow is calculated as cash flow from operating activities before asset retirement obligation expenditures and changes in non-cash operating working capital.

Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow	**Year ended December 31,**		
($ millions)	**2019**	**2018**	**2017**
Cash flow from operating activities	$ 694.2	$ 738.8	$ 476.1
Asset retirement obligation expenditures	16.7	11.3	12.9
Changes in non-cash operating working capital	(1.9)	3.4	35.1
Adjusted funds flow	$ 709.0	$ 753.5	$ 524.1

"Free cash flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating and financial performance, leverage and liquidity. Free cash flow is calculated as adjusted funds flow minus capital spending.

Calculation of Free Cash Flow	**Year ended December 31,**		
($ millions)	**2019**	**2018**	**2017**
Adjusted funds flow	$ 709.0	$ 753.5	$ 524.1
Capital spending	(618.9)	(593.9)	(458.0)
Free cash flow	$ 90.1	$ 159.6	$ 66.1

"Adjusted net income" is used by Enerplus and is useful to investors and securities analysts in evaluating the financial performance of the company by understanding the impact of certain non-cash items and other items that the Company considers appropriate to adjust given the irregular nature and relevance to comparable companies. Adjusted net income is calculated as net income adjusted for unrealized derivative instrument gain/loss, gain on divestment of assets, unrealized foreign exchange gain/loss, the tax effect of these items, goodwill impairment and the impact of statutory changes to the Company's corporate tax rate.

Calculation of Adjusted Net Income	**Year ended December 31,**		
($ millions)	**2019**	**2018**	**2017**
Net income/(loss)	$ (259.7)	$ 378.3	$ 237.0
Unrealized derivative instrument (gain)/loss	81.7	(124.3)	(6.2)
Gain on divestment of assets	—	—	(78.4)
Unrealized foreign exchange (gain)/loss	(34.1)	58.6	(42.6)
Tax effect on above items	(18.5)	32.2	22.4
Goodwill impairment	451.1	—	—
Income tax rate adjustment on deferred taxes	22.7	—	46.2
Adjusted net income	$ 243.2	$ 344.8	$ 178.4

"Total debt net of cash" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. Total debt net of cash is calculated as senior notes plus any outstanding bank credit facility balance, minus cash and cash equivalents.

"Net debt to adjusted funds flow ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The net debt to adjusted funds flow ratio is calculated as total debt net of cash divided by a trailing twelve months of adjusted funds flow. This measure is not equivalent to debt to earnings before interest, taxes, depletion, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") and is not a debt covenant.

"Adjusted payout ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. We calculate our adjusted payout ratio as cash dividends plus capital spending, office expenditures and line fill divided by adjusted funds flow.

Calculation of Adjusted Payout Ratio	**Year ended December 31,**		
($ millions)	**2019**	**2018**	**2017**
Cash dividends	$ 27.7	$ 29.3	$ 29.0
Capital, office expenditures and line fill	629.8	600.4	460.7
Sub-total	$ 657.5	$ 629.7	$ 489.7
Adjusted funds flow	$ 709.0	$ 753.5	$ 524.1
Adjusted payout ratio (%)	93%	84%	93%

"Adjusted EBITDA" is used by Enerplus and its lenders to determine compliance with financial covenants under its bank credit facility and outstanding senior notes.

Reconciliation of Net Income to Adjusted EBITDA(1)	
($ millions)	**December 31, 2019**
Net income/(loss)	$ (259.7)
Add:	
Goodwill impairment	451.1
Interest	33.9
Current and deferred tax expense/(recovery)	47.9
DD&A	356.8
Other non-cash charges(2)	70.7
Adjusted EBITDA	$ 700.7

(1) Adjusted EBITDA is calculated based on the trailing four quarters.
(2) Includes the change in fair value of commodity derivatives, equity swaps, non-cash SBC expense, and unrealized foreign exchange gains/losses.

In addition, the Company uses certain financial measures within the "Overview" and "Liquidity and Capital Resources" sections of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "senior debt to adjusted EBITDA", "senior net debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "senior debt to consolidated present value of total proved reserves" and "adjusted EBITDA to interest" and are used to determine the Company's compliance with financial covenants under its bank credit facility and outstanding senior notes. Calculation of such terms is described under the "Liquidity and Capital Resources" section of this MD&A.

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal controls over financial reporting as defined in Rule 13a – 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at December 31, 2019, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on January 1, 2019 and ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our current Annual Information Form, is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", “guidance”, "ongoing", "may", "will", "project", "plans", “budget”, "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expected 2020 average production volumes, timing thereof and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our adjusted funds flow; anticipated production volumes subject to curtailment; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity risk management program in 2020 and in the future; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash G&A, share-based compensation and financing expenses; operating and transportation costs; our anticipated share repurchases under current and future normal course issuer bids; capital spending levels in 2020 and impact thereof on our production levels and land holdings; potential future asset and goodwill impairments, as well as relevant factors that may affect such impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes; our current and future NCIB and share repurchases thereunder; our future acquisitions and dispositions, expecting timing thereof and use of proceeds therefrom; the amount of future cash dividends that we may pay to our shareholders and our climate initiatives and targets for 2020.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; the availability of third party services; and the extent of our liabilities. In addition, our 2020 guidance contained in this MD&A is based on the following: a WTI price of US$50.00/bbl to US$55.00/bbl, a NYMEX price of US$2.25/Mcf, and a USD/CDN exchange rate of 1.30. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued low commodity prices environment or further volatility in commodity prices; changes in realized prices of Enerplus’ products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors, reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our AIF and Form 40-F as at December 31, 2019).

The purpose of our expected operating expenses, transportation costs and cash G&A expenses, in each case on a per BOE basis, and adjusted funds flow sensitivity is to assist readers in understanding our expected and targeted financial results, and this information may not be appropriate for other purposes. The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2019, our internal control over financial reporting is effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2019, has been audited by KPMG LLP, the Independent Registered Public Accounting Firm, who also audited the Company's Consolidated Financial Statements for the year ended December 31, 2019.

/s/ Ian C. Dundas

President and
Chief Executive Officer

/s/ Jodine J. Jenson Labrie

Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 20, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enerplus Corporation

Opinion on Internal Control Over Financial Reporting

We have audited Enerplus Corporation's (the Company) internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2019 and 2018, the related consolidated statements of income (loss) and comprehensive income (loss), shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements), and our report dated February 20, 2020 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control and Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 20, 2020

Management's Responsibility for Financial Statements

In management's opinion, the accompanying consolidated financial statements of Enerplus Corporation have been prepared within reasonable limits of materiality and in accordance with accounting principles generally accepted in the United States of America. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to February 20, 2020. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization.

The consolidated financial statements have been examined by KPMG LLP, Independent Registered Public Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America. The Report of Independent Registered Public Accounting Firm outlines the scope of their examination and sets forth their opinion.

The Audit Committee, consisting exclusively of independent directors, has reviewed these statements with management and the Independent Registered Public Accounting Firm and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Company.

/s/ Ian C. Dundas

President and
Chief Executive Officer

/s/ Jodine J. Jenson Labrie

Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 20, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enerplus Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Enerplus Corporation (the “Company”) as of December 31, 2019 and 2018, the related consolidated statements of income (loss) and comprehensive income (loss), changes in shareholders’ equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Corporation Accounting Oversight Board (United States) (PCAOB), the Company’s internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 20, 2020 expressed an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Assessment of the carrying value of goodwill for the Canadian reporting unit

As discussed in note 5(b) to the consolidated financial statements, the Company recorded goodwill impairment of $451,121 thousand related to the Canadian reporting unit. The Company assesses goodwill for impairment on an annual basis or more frequently if events or changes in circumstances indicate that the carrying value of the reporting unit likely exceeds the fair value. If it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value. The estimated fair value of the Canadian reporting unit involves a number of estimates, including the cash flows associated with the estimated proved and probable oil and gas reserves of the Canadian reporting unit (“Canadian reserves”) and the discount rate. The estimation of the Canadian reserves require the expertise of independent reservoir engineering specialists, who take into consideration assumptions related to its forecasted production, forecasted operating, royalty and capital cost assumptions and forecasted oil and gas prices (“reserve assumptions”). The Company engages independent reservoir engineering specialists to estimate the Canadian reserves.

We identified the assessment of the carrying value of goodwill for the Canadian reporting unit as a critical audit matter. Complex auditor judgment was required in evaluating the Company’s estimate of the Canadian reserves and the discount rate, which were inputs to the calculation of the fair value of the Canadian reporting unit. Auditor judgment was also required to evaluate the reserve assumptions used in the Canadian reserves.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's determination of the fair value of the Canadian reporting unit, including controls related to the development of the discount rate and the estimation of the Canadian reserves. We performed sensitivity analyses over the discount rate used to estimate the fair value of the Canadian reporting unit to assess the impact of a change in the discount rate on the goodwill impairment charge. We evaluated the competence, capabilities and objectivity of the independent reservoir engineering specialists engaged by the Company, who estimated the Canadian reserves. We evaluated the methodology used by the independent reservoir engineering specialists to estimate the Canadian reserves for compliance with regulatory standards. We compared the 2019 actual production, operating, royalty and capital costs of the Canadian reporting unit to those estimates used in the prior year's estimate of the proved reserves associated with the Canadian reporting unit to assess the Company's ability to accurately forecast. We compared the forecasted commodity prices used in the estimate of the Canadian reserves to those published by other reserve engineering firms. We compared estimates of forecasted production and forecasted operating, royalty and capital cost assumptions used in the Canadian reserves to historical results.

Evaluation of the realizability of the deferred income tax asset associated with the Company's Canadian operation.

As discussed in note 17 to the consolidated financial statements, as of December 31, 2019, the Company had recognized a deferred income tax asset of $372,502 thousand of which $185,880 thousand relates to the Company's Canadian operations. The Company estimated that there is a greater than 50 percent likelihood that the deferred income tax asset will be realized. The determination of the deferred income tax asset associated with the Canadian operation involves a number of estimates, including the future cash flows associated with the estimated Canadian reserves. Changes in assumptions regarding future cash flows, which are based on the estimate of the Canadian reserves, could have a significant impact on the determination on the Company's ability to realize the Canadian operation's deferred income tax asset and the amount of a valuation allowance, if any. The estimation of the Canadian reserves requires the expertise of independent reservoir engineering specialists, who take into consideration reserve assumptions. The Company engages independent reservoir engineering specialists to estimate the Canadian reserves.

We identified the evaluation of the realizability of the Canadian operation's deferred income tax asset as a critical audit matter. Complex auditor judgment was required in evaluating the Canadian reserves which were an input to derive the recognized deferred income tax asset. Auditor judgment was also required to evaluate the reserve assumptions used in the Canadian reserves.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's process to evaluate the realizability of the Canadian deferred income tax assets, including controls related to the estimation of the Canadian reserves. We evaluated the competence, capabilities and objectivity of the independent reservoir engineering specialists engaged by the Company, who estimated the Canadian reserves. We evaluated the methodology used by independent reservoir engineering specialists to estimate the Canadian reserves for compliance with regulatory standards. We compared the 2019 actual production, operating, royalty and capital costs of the Canadian operations to those estimates used in the prior year's estimate of the proved reserves associated with the Canadian operations to assess the Company's ability to accurately forecast. We compared the forecasted commodity prices used in the Canadian reserves to those published by other reserve engineering firms. We compared estimates of forecasted production and forecasted operating, royalty and capital cost assumptions used in the Canadian reserves to historical results. We involved Canadian income tax professionals with specialized skills and knowledge who assisted in evaluating the application of relevant tax laws and regulations used in the determination of the recorded deferred tax asset.

Assessment of the impact of estimated proved oil and gas reserves on the calculations of depletion expense and the ceiling test related to oil and gas properties

As discussed in Note 2(d) to the consolidated financial statements, the Company depletes its oil and gas properties using the unit-of-production method on a country-by-country basis for Canada and the United States of America. Under such method, capitalized costs by country are depleted over the estimated proved oil and gas reserves by for each of Canada and the United States of America ("country proved reserves"). For the year ended December 31, 2019, the Company recorded depletion, depreciation and accretion expense of $356,830 thousand. Additionally, as discussed in Note 2(d) to the consolidated financial statements, the Company is required to perform a ceiling test calculation on a country-by-country basis for Canada and the United States of America. The Company limits the capitalized costs of proved and unproved oil and natural gas properties, net of accumulated depletion and the related deferred income tax effects, by country, to the estimated future net cash flows from country proved reserves discounted at 10 percent, net of related tax effects, plus the lower of cost or fair value of unproved oil and gas properties. The estimated future net cash flows are calculated using the simple average of the preceding twelve months' first-day-of-the-month commodity prices. The estimation of country proved reserves, which are used in the calculations of depletion and the ceiling test, requires the expertise of independent reservoir engineering specialists, who take into consideration reserve assumptions. The Company engages independent reservoir engineering specialists to estimate country proved reserves.

We identified the assessment of the impact of estimated country proved reserves on the calculations of depletion expense and the ceiling test related to oil and gas properties as a critical audit matter. Complex auditor judgment was required in evaluating the country proved reserves, which were an input to the calculations of depletion expense and the ceiling test. Auditor judgment was also required to evaluate the reserve assumptions used to estimate the country proved reserves.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the calculations of depletion expense and the ceiling test, including controls over the estimation of the country proved reserves. We analyzed and assessed the calculations of depletion expense and the ceiling test for compliance with regulatory standards. We evaluated the competence, capabilities and objectivity of the independent reservoir engineering specialists engaged by the Company, who estimated the country proved reserves. We evaluated the methodology used by the independent reservoir engineering specialists to estimate country proved reserves for compliance with regulatory standards. We compared the Company's 2019 actual production, operating, royalty and capital costs by country to those estimates used in the prior year estimate of country proved reserves to assess the Company's ability to accurately forecast. We compared estimates of forecasted production and forecasted operating, royalty and capital cost assumptions used in the country proved reserves to historical results.

/s/ KPMG LLP

We have served as the Company's auditor since 2017.

Chartered Professional Accountants

Calgary, Canada
February 20, 2020

Consolidated Balance Sheets

(CDN$ thousands)	Note	December 31, 2019	December 31, 2018
Assets			
Current assets			
Cash and cash equivalents		$ 151,649	$ 363,327
Accounts receivable	3	176,119	145,206
Income tax receivable	13	27,770	55,172
Derivative financial assets	15(b)	10,570	59,258
Other current assets		2,990	8,928
		369,098	631,891
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	4	1,547,362	1,293,941
Other capital assets, net	4	20,244	13,130
Property, plant and equipment		1,567,606	1,307,071
Right-of-use assets	9	48,729	—
Goodwill	5(b)	194,015	654,799
Derivative financial assets	15(b)	—	32,220
Deferred income tax asset	13	372,502	465,124
Income tax receivable	13	13,852	27,195
Total Assets		$ 2,565,802	$ 3,118,300
Liabilities			
Current liabilities			
Accounts payable	6	$ 291,540	$ 290,045
Dividends payable		2,217	2,395
Current portion of long-term debt	7	105,998	60,001
Derivative financial liabilities	15(b)	2,734	1,909
Current portion of lease liabilities	9	17,541	—
		420,030	354,350
Long-term debt	7	500,635	636,849
Asset retirement obligation	8	138,049	126,112
Lease liabilities	9	35,530	—
		674,214	762,961
Total Liabilities		1,094,244	1,117,311
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: December 31, 2019 – 222 million shares			
December 31, 2018 – 239 million shares	14(a)	3,088,094	3,337,608
Paid-in capital		59,490	46,524
Accumulated deficit		(1,984,365)	(1,772,084)
Accumulated other comprehensive income		308,339	388,941
		1,471,558	2,000,989
Total Liabilities & Shareholders' Equity		$ 2,565,802	$ 3,118,300
Commitments and Contingencies	16		
Subsequent Event	14(a)		

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

Approved on behalf of the Board of Directors:

/s/ Elliott Pew
Director

/s/ Robert B. Hodgins
Director

Consolidated Statements of Income/(Loss) and Comprehensive Income/(Loss)

For the year ended December 31 (CDN$ thousands)	**Note**	**2019**	**2018**	**2017**
Revenues				
Oil and natural gas sales, net of royalties	10	$ 1,254,806	$ 1,292,736	$ 920,693
Commodity derivative instruments gain/(loss)	15(b)	(66,071)	88,232	14,310
		1,188,735	1,380,968	935,003
Expenses				
Operating		290,766	238,261	197,101
Transportation		144,903	123,463	111,265
Production taxes		83,109	87,286	54,318
General and administrative	11	72,853	75,783	74,301
Depletion, depreciation and accretion		356,830	304,274	250,774
Goodwill impairment	5(b)	451,121	—	—
Interest		33,919	36,799	38,714
Foreign exchange (gain)/loss	12	(25,378)	39,521	(30,150)
Gain on divestment of assets	4	—	—	(78,400)
Other expense/(income)		(7,529)	(5,909)	(1,906)
		1,400,594	899,478	616,017
Income/(Loss) Before Taxes		(211,859)	481,490	318,986
Current income tax expense/(recovery)	13	(33,414)	(27,093)	(47,957)
Deferred income tax expense/(recovery)	13	81,275	130,304	129,945
Net Income/(Loss)		$ (259,720)	$ 378,279	$ 236,998
Other Comprehensive Income/(Loss)				
Unrealized gain/(loss) on foreign currency translation		(80,602)	125,817	(90,277)
Total Comprehensive Income/(Loss)		$ (340,322)	$ 504,096	$ 146,721
Net Income/(Loss) per Share				
Basic	14(c)	$ (1.12)	$ 1.55	$ 0.98
Diluted	14(c)	$ (1.12)	$ 1.53	$ 0.96

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

Consolidated Statements of Changes in Shareholders' Equity

For the year ended December 31 (CDN$ thousands)	**2019**	**2018**	**2017**
Share Capital			
Balance, beginning of year	$ 3,337,608	$ 3,386,946	$ 3,365,962
Purchase of common shares under Normal Course Issuer Bid	(253,920)	(82,596)	—
Share-based compensation – treasury settled	4,406	23,389	20,984
Stock Option Plan – cash	—	9,138	—
Stock Option Plan – exercised	—	731	—
Balance, end of year	$ 3,088,094	$ 3,337,608	$ 3,386,946
Paid-in Capital			
Balance, beginning of year	$ 46,524	$ 75,375	$ 73,783
Share-based compensation – cash settled (tax withholding)	(4,952)	—	—
Share-based compensation – cash settled	—	(30,648)	—
Share-based compensation – treasury settled	(4,406)	(23,389)	(20,984)
Share-based compensation – non-cash	22,324	25,917	22,576
Stock Option Plan – exercised	—	(731)	—
Balance, end of year	$ 59,490	$ 46,524	$ 75,375
Accumulated Deficit			
Balance, beginning of year	$ (1,772,084)	$ (2,124,676)	$ (2,332,641)
Purchase of common shares under Normal Course Issuer Bid	75,127	3,569	—
Net income/(loss)	(259,720)	378,279	236,998
Dividends declared ($0.01 per share)	(27,688)	(29,256)	(29,033)
Balance, end of year	$ (1,984,365)	$ (1,772,084)	$ (2,124,676)
Accumulated Other Comprehensive Income			
Balance, beginning of year	$ 388,941	$ 263,124	$ 353,401
Unrealized gain/(loss) on foreign currency translation	(80,602)	125,817	(90,277)
Balance, end of year	$ 308,339	$ 388,941	$ 263,124
Total Shareholders' Equity	$ 1,471,558	$ 2,000,989	$ 1,600,769

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

Consolidated Statements of Cash Flows

For the year ended December 31 (CDN$ thousands)	Note	2019	2018	2017
Operating Activities				
Net income/(loss)		$ (259,720)	$ 378,279	$ 236,998
Non-cash items add/(deduct):				
Depletion, depreciation and accretion		356,830	304,274	250,774
Goodwill impairment	5(b)	451,121	—	—
Changes in fair value of derivative instruments	15(b)	81,733	(124,266)	(6,184)
Deferred income tax expense/(recovery)	13	81,275	130,304	129,945
Foreign exchange (gain)/loss on debt and working capital	12	(34,085)	58,628	(42,623)
Share-based compensation and general and administrative	11, 14(b)	23,044	25,917	22,576
Translation of U.S. dollar cash held in Canada (gain)/loss	12	8,794	(19,630)	10,978
Gain on the divestment of assets	4	—	—	(78,400)
Asset retirement obligation expenditures	8	(16,715)	(11,263)	(12,907)
Changes in non-cash operating working capital	18(a)	1,963	(3,459)	(35,032)
Cash flow from operating activities		694,240	738,784	476,125
Financing Activities				
Proceeds from the issuance of shares (net of issue costs)	14(a)	—	9,138	—
Dividends	14(a),18(b)	(27,866)	(29,282)	(29,017)
Bank credit facility	7	—	—	(23,272)
Senior notes	7	(59,429)	(29,044)	(29,084)
Purchase of common shares under Normal Course Issuer Bid	14(a)	(178,793)	(79,027)	—
Share-based compensation – cash settled (tax withholding)	14(b)	(4,952)	—	—
Cash flow from/(used in) financing activities		(271,040)	(128,215)	(81,373)
Investing Activities				
Capital and office expenditures	18(b)	(606,966)	(604,110)	(459,152)
Property and land acquisitions	4	(24,362)	(18,009)	(13,276)
Property divestments	4	9,539	(919)	56,196
Cash flow from/(used in) investing activities		(621,789)	(623,038)	(416,232)
Effect of exchange rate changes on cash and cash equivalents		(13,089)	29,248	(25,277)
Change in cash and cash equivalents		(211,678)	16,779	(46,757)
Cash and cash equivalents, beginning of year		363,327	346,548	393,305
Cash and cash equivalents, end of year		$ 151,649	$ 363,327	$ 346,548

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

Notes to Consolidated Financial Statements

1) REPORTING ENTITY

These annual audited Consolidated Financial Statements ("Consolidated Financial Statements") and notes present the financial position and results of Enerplus Corporation (the "Company" or "Enerplus") including its Canadian and U.S. subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' head office is located in Calgary, Alberta, Canada.

2) SIGNIFICANT ACCOUNTING POLICIES

The following significant accounting policies are presented to assist the reader in evaluating these Consolidated Financial Statements and, together with the following notes, are an integral part of the Consolidated Financial Statements.

a) Basis of Preparation

Enerplus' Consolidated Financial Statements have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). Certain prior period amounts have been restated to conform with current period presentation.

i. Reporting Currency

These Consolidated Financial Statements are presented in Canadian dollars, which is Enerplus' reporting currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand unless otherwise indicated.

ii. Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Actual results could differ from these estimates, and changes in estimates are recorded when known. Significant estimates made by management include: oil and natural gas reserves and related present value of future cash flows, depreciation, depletion and accretion ("DD&A"), impairment of property, plant and equipment, asset retirement obligations, income taxes, ability to realize deferred income tax assets, impairment assessments of goodwill and the fair value of derivative instruments. Enerplus uses the most current information available and exercises judgment in making these estimates and assumptions. In the opinion of management, these Consolidated Financial Statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies.

iii. Basis of Consolidation

These Consolidated Financial Statements include the accounts of Enerplus and its subsidiaries. Intercompany balances and transactions are eliminated on consolidation. Interests in jointly controlled oil and natural gas assets are accounted for following the concept of undivided interest, whereby Enerplus' proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

The acquisition method of accounting is used to account for acquisitions that meet the definition of a business under U.S. GAAP. The cost of an acquisition is measured as the fair value of the assets transferred, equity instruments issued and liabilities incurred or assumed at the acquisition date. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date.

b) Revenue

Revenue from the sale of crude oil, natural gas and natural gas liquids is measured based on the consideration specified in contracts with customers, net of sales taxes. Enerplus recognizes revenue when it satisfies a performance obligation by transferring control of the product to a customer. This is generally at the time the customer obtains legal title to the product and when it is physically transferred to the contractual delivery points.

Enerplus evaluates its arrangements with third parties and partners to determine if the Company acts as the principal or as an agent. In making this evaluation, management considers if Enerplus retains control of the product being delivered to the end customer. As part of this assessment, management considers whether the Company retains the economic benefits associated with the good being delivered to the end customer. Management also considers whether the Company has the primary responsibility for the delivery of the product, the ability to establish prices or the inventory risk. If Enerplus acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net basis, only reflecting the fee, if any, realized by the Company from the transaction.

c) Transportation

Enerplus generally sells oil and natural gas under two types of agreements which are common in our industry. Both types of agreements include a transportation charge. One is a net-back arrangement, under which the Company sells crude oil or natural gas at the wellhead and collects a price, net of the transportation incurred by the purchaser. In this case, sales are recorded at the price received from the purchaser, net of transportation costs.

Under the other arrangement, Enerplus sells crude oil or natural gas at a specific delivery point, pays transportation to a third party and receives proceeds from the purchaser with no transportation deduction. In this case, transportation costs are recorded as transportation expense on the Consolidated Statements of Income/(Loss). Due to these two distinct selling arrangements, Enerplus' computed realized prices, before the impact of derivative instruments, include revenues which are reported under two separate bases.

d) Oil and Natural Gas Properties

Enerplus uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs incurred in finding oil and natural gas reserves are capitalized, including general and administrative costs attributable to these activities. These costs are recorded on a country-by-country cost centre basis as oil and natural gas properties subject to depletion ("full cost pool"). Costs associated with production and general corporate activities are expensed as incurred.

The net carrying value of both proved and unproved oil and natural gas properties is depleted using the unit of production method using proved reserves, as determined using a constant price assumption of the simple average of the preceding twelve months' first-day-of-the-month commodity prices ("SEC prices"). The depletion calculation takes into account estimated future development costs necessary to bring those reserves into production.

Under full cost accounting, a ceiling test is performed on a cost centre basis. Enerplus limits capitalized costs of proved and unproved oil and natural gas properties, net of accumulated depletion and the related deferred income tax effects, to the estimated future net cash flows from proved oil and natural gas reserves discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties ("the ceiling"). The estimated future net cash flows are calculated using the simple average of the preceding twelve months' first-day-of-the-month commodity prices. If such capitalized costs exceed the ceiling, a write-down equal to that excess is recorded as a non-cash charge to net income. A write-down is not reversed in future periods even if higher oil and natural gas prices subsequently increase the ceiling.

Under full cost accounting rules, divestitures of oil and natural gas properties are generally accounted for as adjustments to capitalized costs, with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would have otherwise significantly altered the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss must be recognized.

e) Other Capital Assets

Other capital assets are recorded at historical cost, net of depreciation, and include furniture, fixtures, leasehold improvements, computer equipment and Company owned line-fill in third party pipelines. Line fill is recorded at lower of cost and net realizable value. Depreciation is calculated on a straight-line basis over the estimated useful life of the respective asset. The cost of repairs and maintenance is expensed as incurred.

f) Cash and Cash Equivalents

Cash and cash equivalents includes cash and highly liquid investments with maturities of less than 90 days.

g) Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. The portion of goodwill that relates to U.S. operations fluctuates due to changes in foreign exchange rates. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

Goodwill is assessed for impairment annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus first performs a qualitative assessment to determine whether events or changes in circumstances indicate that goodwill may be impaired. If it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to earnings in the Consolidated Statements of Income/(Loss). The loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. For the purposes of goodwill impairment testing, Enerplus has two reporting units.

h) Asset Retirement Obligations

Enerplus' oil and natural gas operating activities give rise to dismantling, decommissioning and site remediation activities. Enerplus recognizes a liability for the estimated present value of the future asset retirement obligation liability at each balance sheet date. Upon recognition, the liability is recorded at its estimated fair value. The associated asset retirement cost is capitalized and amortized over the same period as the underlying asset. Changes in the estimated liability and related asset retirement cost can arise as a result of revisions in the estimated amount or timing of cash flows.

Depletion of asset retirement costs and increases in asset retirement obligations resulting from the passage of time are recorded to depreciation, depletion and accretion and charged against net income in the Consolidated Statements of Income/(Loss).

i) Leases

Enerplus determines if an arrangement is a lease at inception. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Operating and finance leases are included in right-of-use ("ROU") assets and the associated lease liability in the Consolidated Balance Sheet.

ROU assets represent the Company's right to use an underlying asset for the lease term and lease liabilities represent the obligation to make lease payments arising from the lease. Lease liabilities are recognized at lease commencement date based on the present value of remaining lease payments over the lease term. A corresponding ROU asset is recognized at the amount of the lease liability, adjusted for lease incentives received. Enerplus uses the implicit rate when readily available, or uses its incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments. Enerplus' lease terms may have options to extend or terminate the lease which are included in the calculation of lease liabilities when it is reasonably certain that it will exercise those options. Lease expense for operating leases is recognized on a straight-line basis over the lease term.

Lease agreements contain both lease and non-lease components which are accounted for separately. For certain equipment leases, a portfolio approach is applied to effectively account for the ROU assets and liabilities. Prior to January 1, 2019, the Company applied lease accounting in accordance with ASC 840.

j) Income Tax

Enerplus uses the liability method of accounting for income taxes. Deferred income tax assets and liabilities are recorded on the temporary differences between the accounting and income tax basis of assets and liabilities, using the enacted tax rates expected to apply when the temporary differences are expected to reverse. Deferred tax assets are reviewed each period and a valuation allowance is provided if, after considering available evidence, it is more likely than not that a deferred tax asset will not be realized. Enerplus considers both positive and negative evidence including historic and expected future taxable income, reversing existing temporary differences and tax basis carry forward periods in making this assessment. A valuation allowance is removed in any period where available evidence indicates all or a portion of the valuation allowance is no longer required. The financial statement effect of an uncertain tax position is recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxation authority. Penalties and interest expense related to income tax are recognized in income tax expense.

k) Financial Instruments

i. Fair Value Measurements

Financial instruments are initially recorded at fair value, defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. For financial instruments carried at fair value, and when disclosing the fair value of financial instruments on certain non-financial items, inputs used in determining the fair value are characterized according to the following fair value hierarchy:

- Level 1 – Inputs represent quoted market prices in active markets for identical assets or liabilities.
- Level 2 – Inputs other than quoted market prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted market prices for similar assets or liabilities in active markets or other market corroborated inputs.
- Level 3 – Inputs that are not observable from objective sources, such as forward prices supported by little or no market activity or internally developed estimates of future cash flows used in a present value model.

Subsequent measurement is based on classification of the financial instrument into one of the following five categories: held-for-trading, held-to-maturity, available-for-sale, loans and receivables or other financial liabilities.

ii. Non-derivative financial instruments

The carrying amount of cash, accounts receivable, income tax receivable, accounts payable, dividends payable and bank credit facilities reported on the Consolidated Balance Sheets approximates fair value. The fair value of the senior notes are considered a level 2 fair value measurement. The fair value of debt has been disclosed in Note 15.

iii. Derivative financial instruments

Enerplus enters into financial derivative contracts in order to manage its exposure to market risks from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Enerplus has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though it considers most of these contracts to be economic hedges. As a result, all financial derivative contracts are classified as held-for-trading and are recorded at fair value based on a Level 2 designation, with changes in fair value recorded in net income. The fair values of these derivative instruments are generally based on an estimate of the amounts that would be paid or received to settle these instruments at the balance sheet date. Enerplus' accounting policy is to not offset the fair values of its financial derivative assets and liabilities.

Realized gains and losses from commodity price risk management activities are recognized in income when the contract is settled. Unrealized gains and losses on commodity price risk management activities are recognized in income based on the changes in fair value of the contracts at the end of the respective reporting period.

Enerplus' crude oil, natural gas and natural gas liquids physical delivery purchase and sales contracts qualify as normal purchases and sales as they are entered into and held for the purpose of receipt or delivery of products in accordance with the Company's expected purchase, sale or usage requirements. As such, these contracts are not considered derivative financial instruments. Settlements on these physical contracts are recognized in net income over the term of the contracts as they occur.

l) Foreign Currency

i. Foreign currency transactions

Transactions denominated in foreign currencies are translated to the functional currency of the entity (Canadian dollars) using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency of the entity using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Foreign currency differences arising on translation are recognized in net income in the period in which they arise.

ii. Foreign operations

Assets and liabilities of Enerplus' U.S. operations, which has a U.S. dollar functional currency, are translated into Canadian dollars at period end exchange rates while revenues and expenses are translated using average rates for the period. Gains and losses from the translation are deferred and included in the cumulative translation adjustment which is recorded in accumulated other comprehensive income.

m) Share-Based Compensation

Enerplus' share-based compensation plans include equity-settled Restricted Share Unit ("RSU") and Performance Share Unit ("PSU") awards made pursuant to its Share Award Incentive Plan ("SAIP"). The Company is authorized to issue up to 3.8% of outstanding common shares from treasury under the SAIP. Enerplus also has a cash-settled Deferred Share Unit ("DSU") Plan for Directors ("Director DSU Plan") and a cash-settled RSU Plan for Directors ("Director RSU Plan").

i. Long-term Incentive ("LTI") Plans

For RSU awards granted under the SAIP, employees receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and vests one-third each year for three years. The value upon vesting is based on the value of the underlying notional shares plus notional accrued dividends over the vesting period.

For PSU awards granted under the SAIP, executives and management receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and they vest at the end of three years. The value upon vesting is based on value of the underlying shares plus notional accrued dividends along with a multiplier that ranges from 0 to 2 depending on Enerplus' performance compared to a peer group of both Canadian and U.S. oil and natural gas producers over the vesting period.

Under Enerplus' Director DSU Plan and Director RSU Plan, directors receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded is based on the annual equity retainer value. Directors may elect to receive all or a portion of their notional shares under either plan. Under the Director DSU Plan, units vest and are paid at a specified date following the director leaving the Board. Under the Director RSU Plan, units vest one-third each year for three years. The value upon vesting is based on the value of the underlying notional shares plus notional accrued dividends over the vesting period. All Director DSU and RSU grants are settled in cash.

Enerplus recognizes non-cash share-based compensation expense over the vesting period of the equity-settled long-term incentive plans, net of realized forfeitures, based on the estimated grant date fair value of the respective awards. The grant date fair value is based on the Company's 20-day volume weighted average price on December 31 prior to the grant date. The fair value for the PSUs is adjusted for the outcome of the performance condition. Share-based compensation charges are recorded on the Consolidated Statements of Income/(Loss) with an offset to paid-in capital. Each period, management performs an estimate of the PSU plan multiplier. Any differences that arise between the actual multiplier on plan settlement and management's estimate is recorded to share-based compensation. On settlement of these plans, amounts previously recorded to paid-in capital are reclassified to share capital.

Enerplus recognizes a liability with respect to its cash-settled long-term incentive plans based on their estimated fair value. The liability is re-measured at each reporting date and at settlement date with any changes in the fair value recorded as share-based compensation, included in general and administrative expense.

ii. Stock options

Enerplus' Stock Option Plan was suspended in 2014 and is now closed. All options outstanding under the plan are fully vested and the expense has been fully recognized. The remaining outstanding stock options will expire in 2020.

n) Net Income/(Loss) Per Share

Basic net income/(loss) per common share is computed by dividing net income/(loss) by the weighted average number of common shares outstanding during the period.

For the diluted net income per common share calculation, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income. The weighted average number of diluted shares is calculated in accordance with the treasury stock method which assumes that the proceeds received from the exercise of all stock options and outstanding RSU's and PSU's would be used to repurchase common shares at the average market price.

o) Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation, environmental and other sources are recognized when it is probable that a liability has been incurred and the amount can be reasonably estimated. Contingencies are adjusted as additional information becomes available or circumstances change.

p) Accounting Changes and Recent Pronouncements Issued

i. Recently adopted accounting standards

Except for the changes below, the Company has consistently applied the accounting policies to all periods presented in these Consolidated Financial Statements.

Enerplus adopted ASC 842 *Leases* effective January 1, 2019 using the modified retrospective method, with ASC 842 applied to all contracts not yet completed as of the date of adoption with the cumulative effect on comparative periods reflected as an adjustment to retained earnings, if applicable. The most significant impact was the recognition of ROU assets and lease liabilities for operating leases, while accounting for finance leases and lessor accounting remained unchanged.

Enerplus elected the practical expedient related to land easements, allowing it to carry forward its accounting treatment for land easements on existing agreements.

The impacts of the adoption of ASC 842 as at January 1, 2019 are as follows:

($ thousands)	As reported as at December 31, 2018	Adjustments	Balance as at January 1, 2019
Right-of-use assets	$ —	$ 50,193	$ 50,193
Current portion of lease liabilities	—	(10,648)	(10,648)
Lease liabilities	—	(39,545)	(39,545)
Total	$ —	$ —	$ —

The standard did not materially impact the Company's Consolidated Statement of Income/(Loss) or Consolidated Statements of Cash Flows.

ii. Future accounting changes

In future accounting periods, the Company will adopt the following Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"):

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments – Credit Losses (Topic 326)*. The ASU changes how entities measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than a direct write down of the amortized cost basis. The new guidance is effective January 1, 2020, and will be applied using a modified retrospective approach. Enerplus has not early adopted the standard and does not expect a material impact to the Consolidated Financial Statements.

In January 2017, the FASB issued ASU 2017-04, *Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment (Topic 350)*. This standard eliminates Step 2 of the goodwill impairment test, and requires a goodwill impairment charge for the amount that the carrying amount of the reporting unit exceeds the reporting unit's fair value. The updated guidance is effective January 1, 2020 and will be applied prospectively. Enerplus has not early adopted this ASU. The amended standard simplifies the goodwill impairment test and will impact the amount of any impairment recorded post adoption.

3) ACCOUNTS RECEIVABLE

($ thousands)	December 31, 2019	December 31, 2018
Accrued revenue	$ 142,048	$ 118,821
Accounts receivable – trade	37,736	30,252
Allowance for doubtful accounts	(3,665)	(3,867)
Total accounts receivable, net of allowance for doubtful accounts	$ 176,119	$ 145,206

4) PROPERTY, PLANT AND EQUIPMENT ("PP&E")

As at December 31, 2019 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties(1)	$ 15,088,724	$ (13,541,362)	$ 1,547,362
Other capital assets	125,265	(105,021)	20,244
Total PP&E	$ 15,213,989	$ (13,646,383)	$ 1,567,606

As at December 31, 2018 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties(1)	$ 14,773,082	$ (13,479,141)	$ 1,293,941
Other capital assets	115,510	(102,380)	13,130
Total PP&E	$ 14,888,592	$ (13,581,521)	$ 1,307,071

(1) All of the Company's unproved properties are included in the full cost pool.

Acquisitions:

For the years ended December 31, 2019 and 2018, Enerplus acquired property and land totaling $24.4 million, and $25.8 million, respectively.

Divestments:

For the years ended December 31, 2019 and 2018, Enerplus disposed of properties for proceeds of $9.6 million and $6.9 million, respectively. Certain asset divestments may result in gains if the divestments cause a significant alteration in the relationship between the cost centre's capitalized costs and proved reserves. During 2019, Enerplus did not recognize any gains on asset divestments (2018 – nil, 2017 – $78.4 million).

5) IMPAIRMENT

a) Impairment of PP&E

There was no impairment recorded for the years ended December 31, 2019, 2018 and 2017.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling test as at December 31, 2019, 2018 and 2017:

Period	WTI Crude Oil US$/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	Exchange Rate US$/CDN
2019	$ 55.85	$ 66.73	$ 2.58	1.33
2018	65.56	69.58	3.10	1.28
2017	51.34	63.57	2.98	1.30

b) Impairment of Goodwill

Enerplus recorded goodwill impairment of $451.1 million on its Canadian reporting unit for the period ended December 31, 2019. The impairment was due to the carrying value of the Canadian reporting unit exceeding its fair value as a result of the cumulative impact of Canadian asset divestments, the shut-in of uneconomic natural gas production in Canada and lower forecasted commodity prices. The estimated fair value of the Canadian reporting unit for the goodwill impairment test was based on the discounted after-tax cash flows associated with the proved and probable reserves of the reporting unit. Other changes in goodwill relate to the impact of foreign exchange movements on U.S. dollar denominated goodwill balances. At December 31, 2019, goodwill consisted entirely of US$149.4 million related to Enerplus' U.S. reporting unit. There was no goodwill impairment for the years ended December 31, 2018 and 2017.

6) ACCOUNTS PAYABLE

($ thousands)	December 31, 2019	December 31, 2018
Accrued payables	$ 105,928	$ 115,388
Accounts payable – trade	185,612	174,657
Total accounts payable	$ 291,540	$ 290,045

7) DEBT

($ thousands)	December 31, 2019	December 31, 2018
Current:		
Senior notes	$ 105,998	$ 60,001
Long-term:		
Bank credit facility	$ —	$ —
Senior notes	500,635	636,849
Total debt	$ 606,633	$ 696,850

Bank Credit Facility

Enerplus has a senior unsecured, covenant-based, US$600 million bank credit facility that matures on October 31, 2023. Drawn fees range between 125 and 315 basis points over bankers' acceptance rates. Standby fees on the undrawn portion of the facility are based on 20% of the drawn pricing. The Company has the ability to request an extension of the facility or repay the entire balance at the end of the term. At December 31, 2019, Enerplus was undrawn on the facility (December 31, 2018 – undrawn).

Senior Notes

During 2019 and 2018, Enerplus made its second and third US$22 million principal repayments on its 2009 senior notes. During 2019, Enerplus made a $30 million bullet repayment on its 2012 senior notes.

The terms and rates of the Company's outstanding senior notes are detailed below:

Issue Date	Interest Payment Dates	Principal Repayment	Coupon Rate	Original Principal ($ thousands)	Remaining Principal ($ thousands)	CDN$ Carrying Value ($ thousands)
September 3, 2014	March 3 and Sept 3	5 equal annual installments beginning September 3, 2022	3.79%	US$200,000	US$105,000	$ 136,395
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	25,980
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$298,000	387,102
June 18, 2009	June 18 and Dec 18	2 equal annual installments on June 18, 2020 and 2021	7.97%	US$225,000	US$44,000	57,156
					Total carrying value	$ 606,633

8) ASSET RETIREMENT OBLIGATION

($ thousands)	December 31, 2019	December 31, 2018
Balance, beginning of year	$ 126,112	$ 117,736
Change in estimates	23,362	16,755
Property acquisition and development activity	2,068	1,565
Divestments	(2,760)	(4,585)
Settlements	(16,715)	(11,263)
Accretion expense	5,982	5,904
Balance, end of year	$ 138,049	$ 126,112

Enerplus has estimated the present value of its asset retirement obligation to be $138.0 million at December 31, 2019 based on a total undiscounted, uninflated liability of $344.7 million (December 31, 2018 – $126.1 million and $343.9 million, respectively). The asset retirement obligation was calculated using a weighted average credit-adjusted risk-free rate of 5.50% and inflation rate of 1.8% (December 31, 2018 – 5.59% and 1.8%, respectively). The majority of Enerplus' asset retirement obligation expenditures are expected to be incurred between 2025 and 2055.

9) LEASES

The Company incurs lease payments related to office space, drilling rig commitments, vehicles and other equipment. Leases are entered into and exited in coordination with specific business requirements which include the assessment of the appropriate durations for the related leased assets. Short-term leases with a lease term of 12 months or less are not recorded on the Consolidated Balance Sheet. Such items are charged to operating expenses and general and administrative expenses in the Consolidated Statement of Income/(Loss), unless the costs are included in the carrying amount of another asset in accordance with other U.S. GAAP.

($ thousands)	At December 31, 2019
Assets	
Operating right-of-use assets	$ 48,729
Liabilities	
Current operating lease liabilities	$ 17,541
Non-current operating lease liabilities	35,530
Total lease liabilities	$ 53,071

Weighted average remaining lease term (years)	
Operating leases	4.3

Weighted average discount rate	
Operating leases	4.1%

The components of lease expense for the year ended December 31, 2019 are as follows:

($ thousands)		2019
Operating lease cost	$	19,483
Short-term lease cost		15,332
Sublease income		(1,072)
Total	$	33,743

Maturities of lease liabilities, all of which are classified as operating leases at December 31, 2019, are as follows:

Maturity of Lease Liabilities ($ thousands)		Operating Leases
2020	$	19,371
2021		14,098
2022		7,674
2023		6,706
2024		6,200
After 2024		3,979
Total lease payments	$	58,028
Less imputed interest		(4,957)
Total discounted lease payments	$	53,071
Current portion of lease liabilities	$	17,541
Non-current portion of lease liabilities	$	35,530

Supplemental information related to leases are as follows:

($ thousands)		December 31, 2019
Cash amounts paid to settle lease liabilities:		
Operating cash flow used for operating leases	$	18,637
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$	20,818

10) OIL AND NATURAL GAS SALES

($ thousands)	2019	2018	2017
Oil and natural gas sales	$ 1,572,955	$ 1,610,899	$ 1,141,770
Royalties(1)	(318,149)	(318,163)	(221,077)
Oil and natural gas sales, net of royalties	$ 1,254,806	$ 1,292,736	$ 920,693

(1) Royalties above do not include production taxes which are reported separately on the Consolidated Statements of Income/(Loss).

Oil and natural gas revenue by country and by product for the years ended December 31, 2019 and 2018 are as follows:

2019 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 177,299	$ 145,814	$ 21,776	$ 7,158	$ 2,551
United States	1,077,507	847,182	215,963	14,355	7
Total	$ 1,254,806	$ 992,996	$ 237,739	$ 21,513	$ 2,558

2018 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 198,263	$ 148,949	$ 32,109	$ 14,075	$ 3,130
United States	1,094,473	834,146	236,825	23,502	—
Total	$ 1,292,736	$ 983,095	$ 268,934	$ 37,577	$ 3,130

(1) Royalties above do not include production taxes which are reported separately on the Consolidated Statements of Income/(Loss).
(2) U.S. sales of crude oil and natural gas relate primarily to the Company's North Dakota and Marcellus properties, respectively. Canadian crude oil sales relate primarily to the Company's waterflood properties.
(3) Includes third party processing income.

Enerplus sells the majority of its production pursuant to variable-price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver a fixed or variable volume of crude oil, natural gas liquids or natural gas to the contract counterparty.

Crude oil, natural gas and natural gas liquids are sold under contracts of varying terms, including multi-year contracts. Revenues are typically collected in the month following production.

11) GENERAL AND ADMINISTRATIVE EXPENSE

($ thousands)	2019	2018	2017
General and administrative expense	$ 49,532	$ 49,943	$ 50,544
Share-based compensation expense	23,321	25,840	23,757
General and administrative expense[1]	$ 72,853	$ 75,783	$ 74,301

(1) Includes cash and non-cash amounts.

12) FOREIGN EXCHANGE

($ thousands)	2019	2018	2017
Realized:			
Foreign exchange (gain)/loss	$ (87)	$ 523	$ 1,495
Translation of U.S. dollar cash held in Canada (gain)/loss	8,794	(19,630)	10,978
Unrealized:			
Translation of U.S. dollar debt and working capital (gain)/loss	(34,085)	58,628	(42,623)
Foreign exchange (gain)/loss	$ (25,378)	$ 39,521	$ (30,150)

13) INCOME TAXES

Enerplus' provision for income tax is as follows:

($ thousands)	2019	2018	2017
Current tax			
Canada	$ (13,910)	$ (400)	$ (407)
United States	(19,504)	(26,693)	(47,550)
Current tax expense/(recovery)	(33,414)	(27,093)	(47,957)
Deferred tax			
Canada	$ 11,023	$ 3,915	$ (17,127)
United States	70,252	126,389	147,072
Deferred tax expense/(recovery)	81,275	130,304	129,945
Income tax expense/(recovery)	$ 47,861	$ 103,211	$ 81,988

The following provides a reconciliation of income taxes calculated at the Canadian statutory rate to the actual income taxes:

($ thousands)	2019	2018	2017
Income/(loss) before taxes			
Canada	$ (437,571)	$ 104,204	$ 146,953
United States	225,712	377,286	172,033
Total income/(loss) before taxes	(211,859)	481,490	318,986
Canadian statutory rate	26.50%	27.00%	27.00%
Expected income tax expense/(recovery)	$ (56,143)	$ 130,002	$ 86,126
Impact on taxes resulting from:			
Foreign and statutory rate differences	$ 27,446	$ (23,859)	$ 157,320
Share-based compensation	(5,398)	(18,102)	5,067
Capital gains and losses	3,994	7,254	(6,337)
Change in valuation allowance	(22,038)	6,292	(162,992)
Amounts in respect of prior periods	(19,451)	—	—
Non-deductible goodwill impairment	119,547	—	—
Other	(96)	1,624	2,804
Income tax expense/(recovery)	$ 47,861	$ 103,211	$ 81,988

During the year, the Alberta corporate income tax rate change resulted in a decrease to the Canadian statutory rate by 0.5% for 2019.

The deferred income tax asset consists of the following:

As at December 31 ($ thousands)	2019	2018
Deferred income tax assets		
Property, plant and equipment	$ 59,896	$ 60,665
Tax loss carry-forwards and other credits	383,600	429,651
Capital loss carryforwards and other capital items	154,532	188,409
Asset retirement obligation	33,569	33,935
Other assets	12,219	14,099
Deferred income tax assets before valuation allowance	643,816	726,759
Valuation allowance	(169,129)	(191,167)
Deferred income tax assets, net	474,687	535,592
Deferred income tax liabilities		
Property, plant and equipment	$ (100,328)	$ (46,284)
Derivative financial instruments	(1,857)	(24,184)
Total deferred income tax liabilities	(102,185)	(70,468)
Total deferred income tax asset	$ 372,502	$ 465,124

As of December 31, 2019, $13.9 million was reclassified from deferred income tax asset to income tax receivable for the AMT refund expected to be realized in 2020 (December 31, 2018 – $27.2 million).

Loss carry-forwards and tax credits available for tax reporting purposes:

As at December 31 ($ thousands)	2019	Expiration Date
Canada		
Capital losses	$ 1,170,000	Indefinite
Non-capital losses	405,000	2028-2039
United States		
Net operating losses – prior to 2018	$ 889,000	2030-2039
Net operating losses – 2018 and thereafter	102,000	Indefinite

Changes in the balance of Enerplus' unrecognized tax benefits are as follows:

($ thousands)	2019	2018	2017
Balance, beginning of year	$ 13,300	$ 13,300	$ 13,300
Settlements	(13,300)	—	—
Balance, end of year	$ —	$ 13,300	$ 13,300

Enerplus settled an outstanding dispute with the Canadian tax authorities in the Company's favor reducing the balance of its unrecognized tax benefit to nil and recorded a current tax recovery of $13.9 million including tax and interest.

A summary of the taxation years, by jurisdiction, that remain subject to examination by the taxation authorities are as follows:

Jurisdiction	Taxation Years
Canada – Federal	2014-2019
United States – Federal	2016-2019

Enerplus and its subsidiaries file income tax returns primarily in Canada and the United States. Matters in dispute with the taxation authorities are ongoing and in various stages of completion.

14) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized: unlimited number of common shares Issued: (thousands)	2019 Shares	2019 Amount	2018 Shares	2018 Amount	2017 Shares	2017 Amount
Balance, beginning of year	239,411	$ 3,337,608	242,129	$ 3,386,946	240,483	$ 3,365,962
Issued for cash:						
Purchase of common shares under Normal Course Issuer Bid	(18,231)	(253,920)	(5,925)	(82,596)	—	—
Stock Option Plan	—	—	668	9,138	—	—
Non-cash:						
Share-based compensation – settled(1)	564	4,406	2,539	23,389	1,646	20,984
Stock Option Plan – exercised	—	—	—	731	—	—
Balance, end of year	221,744	$ 3,088,094	239,411	$ 3,337,608	242,129	$ 3,386,946

(1) The amount of shares issued on LTI settlement is net of employee withholding taxes in 2019.

The Company is authorized to issue an unlimited number of common shares without par value.

For the year ended December 31, 2019, Enerplus declared dividends of $0.12 per weighted average common share totaling $27.7 million (December 31, 2018 – $0.12 per share and $29.3 million, December 31, 2017 – $0.12 per share and $29.0 million).

On March 21, 2019, Enerplus renewed its Normal Course Issuer Bid ("NCIB") to continue to repurchase shares through the facilities of the Toronto Stock Exchange (the "TSX"), New York Stock Exchange and/or alternative Canadian trading systems. Pursuant to the NCIB, the Company was permitted to repurchase for cancellation up to 16,673,015 common shares over a period of twelve months commencing on March 26, 2019. All repurchases are made in accordance with the NCIB at prevailing market prices plus brokerage fees, with consideration allocated to share capital up to the average carrying amount of the shares, and any excess is allocated to accumulated deficit. On November 7, 2019, the Company's Board of Directors approved an increase to the maximum number of common shares that may be repurchased under the NCIB for up to 10% of the public float (or an additional 7,145,578 common shares) until the expiry of the NCIB on March 25, 2020.

For the year ended December 31, 2019, the Company repurchased 18,231,401 common shares under the NCIB at an average price of $9.80 per share, for total consideration of $178.8 million. Of the amount paid, $253.9 million was charged to share capital and $75.1 million was credited to accumulated deficit.

For the year ended December 31, 2018, the Company repurchased 5,925,084 common shares under the NCIB at an average price of $13.33 per share, for total consideration of $79.0 million. Of the amount paid, $82.6 million was charged to share capital and $3.6 million was credited to accumulated deficit.

Subsequent to the year, and up to February 20, 2020, the Company repurchased approximately 340,000 common shares under the NCIB at an average price of $7.44 per share, for total consideration of $2.5 million. The Company also received approval from the Board of Directors to renew the NCIB upon expiry of the existing term on March 25, 2020, subject to approval by the TSX. The proposed renewal is anticipated to be for 10% of the public float (within the meaning under the TSX rules), consistent with the current bid.

b) Share-based Compensation

The following table summarizes Enerplus' share-based compensation expense, which is included in General and Administrative expense on the Consolidated Statements of Income/(Loss):

($ thousands)	2019	2018	2017
Cash:			
Long-term incentive plans expense	$ 689	$ 133	$ 997
Non-Cash:			
Long-term incentive plans expense	22,324	25,917	22,576
Equity swap (gain)/loss	308	(210)	184
Share-based compensation expense	$ 23,321	$ 25,840	$ 23,757

i) LTI Plans

The following table summarizes the PSU, RSU and DSU activity for the twelve months ended December 31, 2019:

For the year ended December 31, 2019	Cash-settled LTI Plans	Equity-settled LTI Plans		Total
(thousands of units)	DSU	PSU[(1)]	RSU	
Balance, beginning of year	391	1,371	1,753	3,515
Granted	99	817	862	1,778
Vested	(68)	—	(1,007)	(1,075)
Forfeited	—	(49)	(77)	(126)
Balance, end of year	422	2,139	1,531	4,092

(1) Based on underlying awards before any effect of the performance multiplier.

Cash-settled LTI Plans

For the year ended December 31, 2019, the Company made cash payments of $0.9 million related to its cash-settled plans (2018 – $0.5 million, 2017 – $0.1 million).

As of December 31, 2019, a liability of $3.9 million (December 31, 2018 – $4.1 million) with respect to the Director DSU Plan has been recorded to Accounts Payable on the Consolidated Balance Sheets.

Equity-settled LTI Plans

The following table summarizes the cumulative share-based compensation expense recognized to-date which is recorded to Paid-in Capital on the Consolidated Balance Sheets. Unrecognized amounts will be recorded to non-cash share-based compensation expense over the remaining vesting terms.

At December 31, 2019 ($ thousands, except for years)	PSU[(1)]	RSU	Total
Cumulative recognized share-based compensation expense	$ 30,768	$ 13,495	$ 44,263
Unrecognized share-based compensation expense	11,971	5,582	17,553
Fair value	$ 42,739	$ 19,077	$ 61,816
Weighted-average remaining contractual term (years)	1.7	1.4	

(1) Includes estimated performance multipliers.

The Company directly withholds shares on PSU and RSU settlements for tax-withholding purposes. For the year ended December 31, 2019, $5.0 million (2018, 2017 – nil) in cash withholding taxes were paid.

ii) Stock Option Plan

At December 31, 2019, all stock options are fully vested and all non-cash share-based compensation expense has been fully recognized.

The following table summarizes the stock option plan activity for the year ended December 31, 2019:

Year ended December 31, 2019	Number of Options (thousands)	Weighted Average Exercise Price
Options outstanding, beginning of year	4,131	$ 17.12
Exercised	—	—
Forfeited	(96)	15.22
Expired	(1,928)	20.35
Options outstanding and exercisable, end of year	2,107	$ 14.24

At December 31, 2019, 2,106,944 options were exercisable at a weighted average exercise price of $14.24 with a weighted average remaining contractual term of 0.2 years, giving an aggregate intrinsic value of nil (December 31, 2018 – nil, December 31, 2017 – nil).

c) Basic and Diluted Net Income/(Loss) Per Share

Net income/(loss) per share has been determined as follows:

(thousands, except per share amounts)	2019	2018	2017
Net income/(loss)	$ (259,720)	$ 378,279	$ 236,998
Weighted average shares outstanding – Basic	231,334	244,076	241,929
Dilutive impact of share-based compensation(1)	—	3,185	5,945
Weighted average shares outstanding – Diluted	231,334	247,261	247,874
Net income/(loss) per share			
Basic	$ (1.12)	$ 1.55	$ 0.98
Diluted	$ (1.12)	$ 1.53	$ 0.96

(1) For the year ended December 31, 2019, the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the loss per share.

15) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At December 31, 2019, senior notes had a carrying value of $606.6 million and a fair value of $613.8 million (December 31, 2018 – $696.9 million and $695.4 million, respectively).

There were no transfers between fair value hierarchy levels during the year.

b) Derivative Financial Instruments

The derivative financial assets and liabilities on the Consolidated Balance Sheets result from recording derivative financial instruments at fair value.

The following tables summarize the change in fair value for the respective years:

Gain/(Loss) ($ thousands)	2019	2018	2017	Income Statement Presentation
Equity Swaps	$ (308)	$ 210	$ (184)	G&A expense
Electricity Swaps	—	—	639	Operating expense
Commodity Derivative Instruments:				
Oil	(70,481)	114,822	(5,445)	Commodity derivative instruments
Gas	(10,944)	9,234	11,174	
Total Unrealized Gain/(Loss)	$ (81,733)	$ 124,266	$ 6,184	

The following table summarizes the effect of Enerplus' commodity derivative instruments on the Consolidated Statements of Income/(Loss):

($ thousands)	2019	2018	2017
Change in fair value gain/(loss)	$ (81,425)	$ 124,056	$ 5,729
Net realized cash gain/(loss)	15,354	(35,824)	8,581
Commodity derivative instruments gain/(loss)	$ (66,071)	$ 88,232	$ 14,310

The following table summarizes the fair values at the respective year ends:

	December 31, 2019		December 31, 2018		
	Assets	Liabilities	Assets		Liabilities
($ thousands)	Current	Current	Current	Long-term	Current
Equity Swaps	$ —	$ 2,217	$ —	$ —	$ 1,909
Commodity Derivative Instruments:					
Oil	10,570	517	48,314	32,220	—
Gas	—	—	10,944	—	—
Total	$ 10,570	$ 2,734	$ 59,258	$ 32,220	$ 1,909

c) Risk Management

In the normal course of operations, Enerplus is exposed to various market risks, including commodity prices, foreign exchange, interest rates and equity prices, credit risk and liquidity risk.

i) Market Risk

Market risk is comprised of commodity price, foreign exchange, interest rate and equity price risk.

Commodity Price Risk:

Enerplus manages a portion of commodity price risk through a combination of financial derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts subject to a maximum of 80% of forecasted production volumes net of royalties and production taxes.

The following tables summarize Enerplus' price risk management positions at February 20, 2020:

Crude Oil Instruments:

Instrument Type(1)(2)	bbls/day	US$/bbl
Jan 1, 2020 – Jan 31, 2020		
WTI Swap	5,000	57.05
WTI Purchased Put	16,000	57.50
WTI Sold Put	16,000	46.88
WTI – Brent Swap (Purchase)	4,400	(8.03)
WTI – Brent Swap (Sale)	4,400	(3.98)
WCS Differential Swap	1,000	(19.25)
Feb 1, 2020 – Mar 31, 2020		
WTI Swap	10,000	54.56
WTI Purchased Put	16,000	57.50
WTI Sold Put	16,000	46.88
WTI – Brent Swap (Purchase)	4,400	(8.03)
WTI – Brent Swap (Sale)	4,400	(3.98)
WCS Differential Swap	1,000	(19.25)
Apr 1, 2020 – Jun 30, 2020		
WTI Swap	12,000	55.23
WTI Purchased Put	16,000	57.50
WTI Sold Put	16,000	46.88
WTI – Brent Swap (Purchase)	4,400	(8.03)
WTI – Brent Swap (Sale)	4,400	(3.98)
Jul 1, 2020 – Sep 30, 2020		
WTI Swap	2,000	57.18
WTI Purchased Put	21,000	57.20
WTI Sold Put	21,000	47.14
WTI Sold Call	5,000	65.00
WTI – Brent Swap (Purchase)	4,400	(8.03)
Oct 1, 2020 – Dec 31, 2020		
WTI Purchased Put	21,000	57.20
WTI Sold Put	21,000	47.14
WTI Sold Call	5,000	65.00
WTI – Brent Swap (Purchase)	4,400	(8.03)

(1) Transactions with a common term have been aggregated and presented as the weighted average price/bbl before premiums.
(2) The total average deferred premium on outstanding hedges is US$1.69/bbl from January 1, 2020 to December 31, 2020.

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations, U.S. dollar denominated senior notes, cash deposits and working capital. Additionally, Enerplus' crude oil sales and a significant portion of its natural gas sales are based on U.S. dollar indices. To mitigate exposure to fluctuations in foreign exchange, Enerplus may enter into foreign exchange derivatives. At December 31, 2019, Enerplus did not have any foreign exchange derivatives outstanding.

Interest Rate Risk:

At December 31, 2019, all of Enerplus' debt was based on fixed interest rates, and Enerplus did not have any interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 14. Enerplus has entered into various equity swaps maturing in 2020 and has effectively fixed the future settlement cost on 264,000 shares at a weighted average price of $17.82 per share.

ii) Credit Risk

Credit risk represents the financial loss Enerplus would experience due to the potential non-performance of counterparties to its financial instruments. Enerplus is exposed to credit risk mainly through its joint venture, marketing and financial counterparty receivables.

Enerplus mitigates credit risk through credit management techniques, including conducting financial assessments to establish and monitor counterparties' credit worthiness, setting exposure limits, monitoring exposures against these limits and obtaining financial assurances such as letters of credit, parental guarantees, or third party credit insurance where warranted. Enerplus monitors and manages its concentration of counterparty credit risk on an ongoing basis.

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At December 31, 2019, approximately 77% of Enerplus' marketing receivables were with companies considered investment grade.

Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts off future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at December 31, 2019 was $3.7 million (December 31, 2018 – $3.9 million).

iii) Liquidity Risk & Capital Management

Liquidity risk represents the risk that Enerplus will be unable to meet its financial obligations as they become due. Enerplus mitigates liquidity risk through actively managing its capital, which it defines as debt (net of cash and cash equivalents) and shareholders' capital. Enerplus' objective is to provide adequate short and longer term liquidity while maintaining a flexible capital structure to sustain the future development of its business. Enerplus strives to balance the portion of debt and equity in its capital structure given its current oil and natural gas assets and planned investment opportunities.

Management monitors a number of key variables with respect to its capital structure, including debt levels, capital spending plans, dividends, share repurchases, access to capital markets, as well as acquisition and divestment activity.

At December 31, 2019, Enerplus was in full compliance with all covenants under the bank credit facility and outstanding senior notes.

16) COMMITMENTS AND CONTINGENCIES

a) Commitments

Enerplus has the following minimum annual commitments, excluding operating leases which are recorded in the lease liability (see Note 9):

($ thousands)	Total	Minimum Annual Commitment Each Year 2020	2021	2022	2023	2024	Thereafter
Senior notes(1)	$ 606,633	$ 105,998	$ 105,998	$ 130,680	$ 104,700	$ 104,699	$ 54,558
Transportation commitments	313,197	34,829	31,651	29,271	28,981	28,719	159,746
Processing commitments	12,663	3,174	1,519	1,519	1,519	1,519	3,413
Total commitments(2)(3)	$ 932,493	$ 144,001	$ 139,168	$ 161,470	$ 135,200	$ 134,937	$ 217,717

(1) Interest payments have not been included.
(2) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(3) US$ commitments have been converted to CDN$ using the December 31, 2019 foreign exchange rate of 1.2990.

b) Contingencies

Enerplus is subject to various legal claims and actions arising in the normal course of business. Although the outcome of such claims and actions cannot be predicted with certainty, the Company does not expect these matters to have a material impact on the Consolidated Financial Statements. In instances where the Company determines that a loss is probable and the amount can be reasonably estimated, an accrual is recorded.

17) GEOGRAPHICAL INFORMATION

As at and for the year ended December 31, 2019 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 177,299	$ 1,077,507	$ 1,254,806
Depletion, depreciation and accretion	59,936	296,894	356,830
Property, plant and equipment	259,514	1,308,092	1,567,606
Deferred income tax asset	185,880	186,622	372,502
Goodwill	—	194,015	194,015
Long term income tax receivable	—	13,852	13,852

As at and for the year ended December 31, 2018 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 198,263	$ 1,094,473	$ 1,292,736
Depletion, depreciation and accretion	58,333	245,941	304,274
Property, plant and equipment	262,159	1,044,912	1,307,071
Deferred income tax asset	196,903	268,221	465,124
Goodwill	451,121	203,678	654,799
Long term income tax receivable	—	27,195	27,195

As at and for the year ended December 31, 2017 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 227,031	$ 693,662	$ 920,693
Depletion, depreciation and accretion	89,936	160,838	250,774
Property, plant and equipment	246,604	653,427	900,031
Deferred income tax asset	200,818	369,119	569,937
Goodwill	451,121	187,757	638,878
Long term income tax receivable	—	50,108	50,108

18) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	December 31, 2019	December 31, 2018	December 31, 2017
Accounts receivable	$ 8,493	$ (45,385)	$ (66,860)
Other assets	4,475	(3,026)	(154)
Accounts payable	(11,005)	44,952	31,982
	$ 1,963	$ (3,459)	$ (35,032)

b) Changes in Other Non-Cash Working Capital

($ thousands)	December 31, 2019	December 31, 2018	December 31, 2017
Non-cash financing activities(1)	$ (178)	$ (26)	$ 16
Non-cash investing activities(2)	$ 17,682	$ (3,753)	$ 1,523

(1) Relates to changes in dividends payable and included in dividends on the Consolidated Statements of Cash Flows.
(2) Relates to changes in accounts payable for capital and office expenditures and included in capital and office expenditures on the Consolidated Statements of Cash Flows.

c) Other

($ thousands)	December 31, 2019	December 31, 2018	December 31, 2017
Income taxes paid/(received)	$ (71,890)	$ (481)	$ 2,640
Interest paid	$ 33,991	$ 36,161	$ 38,149

FIVE YEAR SUMMARY

	2019	2018	2017	2016	2015
Daily Production Volumes[(1)]					
Crude oil (bbls/day)	49,704	45,424	36,935	38,353	41,639
Natural gas liquids (bbls/day)	4,929	4,486	3,858	4,903	4,763
Natural gas (Mcf/day)	278,451	259,837	263,506	299,214	360,733
BOE per day	101,042	93,216	84,711	93,125	106,524
Drilling Activity (net wells)	56	61	46	25	46
Average Benchmark Pricing					
WTI crude oil (US$ per bbl)	$ 57.03	$ 64.77	$ 50.95	$ 43.32	$ 48.80
Brent (ICE) crude oil (US$/bbl)	64.18	71.53	54.83	45.04	53.64
NYMEX natural gas - last day (US$ per Mcf)	2.63	3.09	3.11	2.46	2.66
USD/CDN exchange rate (average)	1.33	1.30	1.30	1.32	1.28
Realized Pricing[(2)]					
Crude oil (per bbl)	$ 68.98	$ 74.59	$ 58.69	$ 44.84	$ 48.43
Natural gas liquids(per bbl)	15.19	28.31	30.01	15.29	18.06
Natural gas (per Mcf)	2.87	3.42	3.21	2.06	2.15
Financial ($ thousands, except per share amounts)					
Oil and natural gas sales[(2)]	$ 1,572,955	$ 1,610,899	$ 1,141,770	$ 882,126	$ 1,052,381
Cash flow from operating activities	694,240	738,784	476,125	312,290	465,336
Adjusted funds flow[(3)]	708,992	753,506	524,064	305,605	493,101
Cash and stock dividends to Shareholders	27,688	29,256	29,033	35,439	131,955
Per share	0.12	0.12	0.12	0.16	0.64
Capital spending	618,910	593,876	458,015	209,135	493,403
Property and land acquisitions	24,406	25,840	13,276	126,126	9,552
Property divestitures	9,583	6,912	56,196	670,364	286,614
Total net capital expenditures[(4)]	644,610	619,285	417,755	(333,627)	220,813
Total assets	2,565,802	3,118,300	2,645,832	2,638,850	2,581,234
Total debt net of cash and restricted cash	454,984	333,523	325,831	375,520	1,216,184
Adjusted payout ratio[(3)(5)]	93%	84%	93%	80%	128%
Net debt to adjusted funds flow ratio	0.6x	0.4x	0.6x	1.2x	2.5x
Royalties and production taxes rate	25.5%	25.2%	24.1%	22.3%	20.8%
Oil and Gas Economics per BOE					
Oil & natural gas sales[(2)]	$ 42.65	$ 47.35	$ 36.93	$ 25.88	$ 27.07
Transportation costs	(3.93)	(3.63)	(3.60)	(3.14)	(2.95)
Royalties and production taxes	(10.88)	(11.92)	(8.91)	(5.77)	(5.63)
Cash gains/(losses) on commodity derivative instruments	0.42	(1.05)	0.28	2.36	7.40
Average realized price, net	28.26	30.75	24.70	19.33	25.89
Cash operating expenses	(7.88)	(7.00)	(6.39)	(7.31)	(8.75)
Netback, after hedging[(3)]	20.38	23.75	18.31	12.02	17.14
Cash general and administrative expenses	(1.34)	(1.48)	(1.66)	(1.84)	(2.11)
Cash interest, foreign exchange and other expenses	(0.72)	(0.92)	(1.24)	(1.28)	(2.78)
Current income tax recovery/(expense)	0.91	0.80	1.55	0.07	0.43
Adjusted funds flow[(3)]	$ 19.23	$ 22.15	$ 16.96	$ 8.97	$ 12.68
Trading Information					
Canadian trading summary[(6)]					
High	$ 12.55	$ 18.04	$ 13.35	$ 13.55	$ 16.09
Low	$ 7.32	$ 9.65	$ 8.97	$ 2.68	$ 4.24
Close	$ 9.25	$ 10.62	$ 12.31	$ 12.74	$ 4.75
Volume (in 000's)	508,744	533,666	520,460	688,243	550,742
U.S. trading summary[(7)]					
High	$ 9.74	$ 13.87	$ 10.21	$ 10.33	$ 13.16
Low	$ 5.50	$ 6.84	$ 6.52	$ 1.84	$ 3.01
Close	$ 7.13	$ 7.76	$ 9.79	$ 9.48	$ 3.42
Volume (in 000's)	250,782	245,759	261,215	347,941	382,094
Weighted average number of shares outstanding (basic)[(8)]	231,334	244,076	241,929	226,530	206,205
Number of shares outstanding at December 31[(8)]	221,744	239,411	242,129	240,483	206,539

(1) Production is on a company interest basis.
(2) Before transportation, royalties and the effects of commodity derivative instruments.
(3) These non-GAAP measures may not be directly comparable to similar measures presented by other entities. See “Non-GAAP Measures” section in the MD&A
(4) Includes office capital and line fill.
(5) Calculated as the sum of cash dividends to shareholders, office capital, line fill and capital spending, divided by adjusted funds flow.
(6) Canadian composite trading data including TSX thereafter.
(7) U.S. composite trading data including NYSE thereafter.
(8) All shares are in thousands.

($ thousands)	2019	2018	2017	2016	2015
Reserves [1]					
Proved Reserves					
Crude oil (Mbbls)	140,703	137,348	122,543	119,419	131,778
NGLs (Mbbls)	14,327	13,783	13,000	11,825	10,704
Conventional natural gas (MMcf)	24,242	31,007	55,992	95,769	183,564
Shale gas (MMcf)	933,737	849,063	803,018	726,614	625,081
MBOE	314,693	297,809	278,711	268,308	277,255
Probable Reserves					
Crude oil (Mbbls)	77,498	70,870	68,479	56,798	58,222
NGLs (Mbbls)	8,396	7,277	7,752	6,273	4,993
Conventional natural gas (MMcf)	7,395	10,129	21,289	30,521	53,802
Shale gas (MMcf)	233,613	300,449	233,742	276,169	338,288
MBOE	126,061	129,909	118,737	114,186	128,563
Proved Plus Probable Reserves					
Crude oil (Mbbls)	218,201	208,215	191,022	176,216	189,999
NGLs (Mbbls)	22,723	21,060	20,752	18,098	15,697
Conventional natural gas (MMcf)	31,637	41,137	77,281	126,290	237,366
Shale gas (MMcf)	1,167,349	1,149,511	1,036,760	1,002,783	963,368
MBOE	440,755	427,718	397,448	382,493	405,818
Reserves Life Index [2]					
Proved (years)	8.9	8.4	9.2	9.0	9.0
Proved plus probable (years)	12.0	11.3	12.6	12.3	12.2
Finding & Development Costs and Finding, Development & Acquisition Costs [3]					
Proved Reserves					
Finding & Development Costs					
Capital expenditures	$ 618.9	$ 593.8	$ 458.0	$ 209.1	$ 493.4
Net change in future development costs	$ 2.4	$ 309.3	$ 114.0	$ (124.4)	$ 210.0
Gross reserves additions (MMBOE)	54.6	54.1	50.5	47.2	50.7
F&D costs ($/BOE)	**$ 11.37**	**$ 16.69**	**$ 11.32**	**$ 1.79**	**$ 13.88**
Finding, Development & Acquisition Costs					
Capital expenditures and net acquisitions	$ 633.7	$ 612.7	$ 415.1	$ (335.1)	$ 216.2
Net change in future development costs	$ (0.5)	$ 308.3	$ 96.7	$ (202.1)	$ 139.7
Gross reserves additions (MMBOE)	53.6	52.9	41.0	24.7	31.1
FD&A costs ($/BOE)	**$ 11.82**	**$ 17.42**	**$ 12.48**	**$ (21.74)**	**$ 11.44**
Proved Plus Probable Reserves					
Finding & Development Costs					
Capital expenditures	$ 618.9	$ 593.8	$ 458.0	$ 209.1	$ 493.4
Net change in future development costs	$ 47.0	$ 309.1	$ 102.8	$ (4.0)	$ (142.2)
Gross reserves additions (MMBOE)	51.0	65.7	58.0	42.6	41.6
F&D costs ($/BOE)	**$ 13.05**	**$ 13.74**	**$ 9.68**	**$ 4.82**	**$ 8.44**
Finding, Development & Acquisition Costs					
Capital expenditures and net acquisitions	$ 633.7	$ 612.7	$ 415.1	$ (335.1)	$ 216.2
Net change in future development costs	$ 44.0	$ 308.1	$ 85.1	$ (94.5)	$ (212.5)
Gross reserves additions (MMBOE)	49.7	64.1	45.6	10.3	14.9
FD&A costs ($/BOE)	**$ 13.63**	**$ 14.37**	**$ 10.98**	**$ (41.60)**	**$ 0.25**

(1) Reserves are based on gross reserves volumes.
(2) The Reserves Life Indices (RLI) are based upon year-end proved and proved plus probable reserves divided by the following year's proved and proved plus probable working interest production volumes as forecast in the independent reserves engineering reports.
(3) Includes future development capital.

ABBREVIATIONS

bbl(s)/day barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons

Bcf billion cubic feet

BOE(1) barrels of oil equivalent

Brent crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $US dollars.

DAPL Dakota Access pipeline

LTI long-term incentive

F&D Costs finding and development costs

FD&A Costs finding, development and acquisition costs

FDC future development capital

Mbbls thousand barrels

MBOE thousand barrels of oil equivalent

Mcf thousand cubic feet

Mcfe thousand cubic feet equivalent

MMcf million cubic feet

MMBOE million barrels of oil equivalent

MSW Mixed Sweet Blend is the benchmark for conventionally produced light sweet crude for Western Canada

NCIB Normal Course Issuer Bid

NGL natural gas liquid

NI 51-101 National Instrument 51-101 Oil and Gas Activities adopted by the Canadian Securities regulatory Authorities (pertaining to reserves reporting in Canada)

NYMEX New York Mercantile Exchange, the benchmark for North American natural gas pricing

2P Reserves proved plus probable reserves

RLI reserves life index

SBC share based compensation

SEC United States Securities and Exchange Commission

Transco Leidy Price benchmark for Marcellus natural gas delivered into the Transco pipeline system between Hunterdon County, New Jersey and connections east of the Leidy storage facility in Clinton and Potter Counties in Pennsylvania

Transco Z6 Non-New York Price benchmark for Marcellus natural gas delivered into the Transco pipeline system from the start of zone 6 at the Virginia-Maryland border to the Linden, New Jersey, compressor station and on the 24-inch pipeline to the Wharton, Pennsylvania, station

DAPL Dakota Access Pipeline

U.S. GAAP accounting principles generally accepted in the United States of America

WCS Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing purposes

WTI West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

(1) The Corporation has adopted the standard of 6 Mcf of natural gas: 1 bbl of oil when converting natural gas to BOEs, MBOEs and MMBOEs, and 1 bbl of oil and NGLs: 6 Mcf of natural gas when converting oil and NGLs to BcfGEs. For further information, see "*Presentation of Oil and Gas Reserves*, *Resources and Production Information – Barrels of Oil and Cubic Feet of Gas Equivalent*" in the Annual Information Form.

Contingent Resources Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early project stage. "Economic" contingent resources are those resources that are economically recoverable based on the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants Ltd., and Sproule Associates Limited as of January 1, 2020.

The economic contingent resources estimates are presented as the "best estimate" of the quantity that will actually be recovered, meaning that it is equally likely that the actual remaining quantities recovered will be greater or less than the "best estimate", and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the "best estimate".

BOE Barrels of oil equivalent converting 6 Mcf of natural gas to one barrel of oil equivalent and one barrel of natural gas liquids to one barrel of oil equivalent. The factor used to convert natural gas and natural gas liquids to oil equivalent is not based on either energy content or prices but is a commonly used industry benchmark. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Future Development Costs (FDC) Future Development Costs is defined as those costs which reflect the independent evaluator's best estimate of what it will cost to bring the proved and probable non-producing and undeveloped reserves on production in the future. Changes to this figure occur annually as a result of development activities, acquisition and disposition activities, additions to non-producing and undeveloped reserves and capital cost estimate revisions.

F&D Costs Finding and development costs. It is a measure of the effectiveness of a company's capital program. F&D costs presented are calculated (i) in the case of F&D costs for proved reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves in the year, and (ii) in the case of F&D costs for proved plus probable reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding and development costs related to its reserves additions for that year. F&D costs are presented in Canadian dollars per working interest BOE unless otherwise specified.

FD&A Costs Finding, development and acquisition costs. It is a measure of a company's ability to add reserves in a cost-effective manner. FD&A costs presented are calculated (i) in the case of FD&A costs for proved reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves including net acquisitions in the year, and (ii) in the case of FD&A costs for proved plus probable reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves including net acquisitions in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding, development and acquisition costs related to its reserves additions for that year. FD&A costs are presented in Canadian dollars per working interest BOE unless otherwise specified.

NGLs Natural gas liquids – hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

Production, Company Interest Our working interest (operated and non-operated) share of production before the deduction of royalties, but inclusive of any royalty interest production owned by Enerplus. Therefore, the "company interest" production of the Corporation may not be comparable to similar measures presented by other issuers, and investors are cautioned that "company interest" production should not be construed as an alternative to "gross" or "net" production calculated in accordance with NI 51-101.

Production, Gross Our working interest (operated and non-operated) share of production before the deduction of any royalty interest production. Unless otherwise stated, all production volumes utilized in any discussions or calculations are gross production volumes.

Reserves Life Index, Proved Calculated as proved reserves at year-end divided by the following year's estimated proved working interest production volumes as determined by the independent reserves engineering report.

Reserves Life Index, Proved plus Probable Calculated as proved plus probable reserves at year-end divided by the following year's estimated proved plus probable working interest production volumes as determined by the independent reserves engineering report.

Reserves, Gross Our working interest (operated and non-operated) share of reserves before the deduction of any royalty interest reserves but exclusive of royalty interest reserves owned by Enerplus.

Reserves, Net Our working interest (operated and non-operated) share of reserves after the deduction of royalty interest reserves but inclusive of any royalty interest reserves owned by Enerplus.

Reserves, Probable Additional reserves, calculated in accordance with NI 51-101, that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Reserves, Proved Reserves that can be estimated with a high degree of certainty to be recoverable in accordance with NI 51-101. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Reserves, Developed Non-Producing Reserves that have either not been on production or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

Reserves, Developed Producing Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Reserves, Undeveloped Reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production.

BOARD OF DIRECTORS

Elliott Pew[1][2]

Corporate Director
Boerne, Texas

Judith D. Buie[5][7]

Corporate Director
Houston, Texas

Karen E. Clarke-Whistler[3][11]

Corporate Director
Toronto, Ontario

Michael R. Culbert[3][5][10]

Corporate Director
Calgary, Alberta

Ian C. Dundas

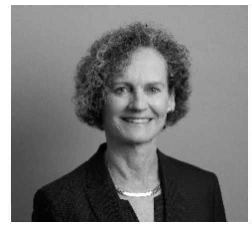
President & Chief Executive Officer
Enerplus Corporation
Calgary, Alberta

Hilary A. Foulkes[4][7][9][11]

Corporate Director
Calgary, Alberta

Robert B. Hodgins[3][6][9]

Corporate Director
Calgary, Alberta



Susan M. MacKenzie[5][7][12]

Corporate Director
Calgary, Alberta

Jeffrey W. Sheets[5][9][11]

Corporate Director
Houston, Texas

Sheldon B. Steeves[8][11]

Corporate Director
Calgary, Alberta

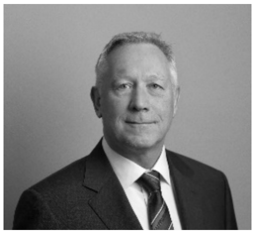
(1) Chairman of the Board
(2) *Ex-Officio* member of all Committees of the Board
(3) Member of the Corporate Governance & Nominating Committee
(4) Chair of the Corporate Governance & Nominating Committee
(5) Member of the Audit & Risk Management Committee
(6) Chair of the Audit & Risk Management Committee
(7) Member of the Reserves Committee
(8) Chair of the Reserves Committee
(9) Member of the Compensation & Human Resources Committee
(10) Chair of the Compensation & Human Resources Committee
(11) Member of the Safety & Social Responsibility Committee
(12) Chair of the Safety & Social Responsibility Committee

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas

President &
Chief Executive Officer



Raymond J. Daniels

Senior Vice President,
Operations, People & Culture

Wade D. Hutchings

Senior Vice President & Chief
Operating Officer

Jodine J. Jenson Labrie

Senior Vice President & Chief
Financial Officer

Garth R. Doll

Vice President, Marketing

Terry S. Eichinger

Vice President, U.S.
Operations & Engineering

Nathan D. Fisher

Vice President, U.S.
Development & Geosciences

Daniel J. Fitzgerald

Vice President, Business
Development

John E. Hoffman

Vice President, Canadian
Operations

David A. McCoy

Vice President, General
Counsel & Corporate
Secretary

Edward L. McLaughlin

President,
U.S. Operations

Shaina B. Morihira

Vice President, Finance

CORPORATE INFORMATION

Operating Companies Owned by Enerplus Corporation

Enerplus Resources (USA) Corporation

Legal Counsel
Blake, Cassels & Graydon LLP
Calgary, Alberta

Auditors
KPMG LLP
Calgary, Alberta

Transfer Agent
Computershare Trust Company of Canada
Calgary, Alberta
Toll free: 1.866.921.0978

U.S. Co-Transfer Agent
Computershare Trust Company, N.A.
Golden, Colorado

Independent Reserves Engineers
McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

Stock Exchange Listings and Trading Symbols
Toronto Stock Exchange: ERF
New York Stock Exchange: ERF

U.S. Office
U.S. Bank Tower
Suite 2200, 950 17th Street
Denver, Colorado 80202-2805

Telephone: 720.279.5500
Fax: 720.279.5550

Annual Meeting
Shareholders are encouraged to attend the Annual Meeting being held on:

Thursday, May 7, 2020
1:00 p.m., MT
Enerplus Corporation
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enerPLUS

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