enerPLUS

Third Quarter Report

Nine Months Ended September 30, 2019

SELECTED FINANCIAL RESULTS	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Financial (000's)				
Net Income	$ 65,181	$ 86,923	$ 169,423	$ 128,964
Cash Flow from Operating Activities	159,806	216,098	505,748	517,165
Adjusted Funds Flow[4]	175,277	210,351	530,070	539,221
Dividends to Shareholders - Declared	6,836	7,355	21,032	22,022
Total Debt Net of Cash[4]	521,379	313,591	521,379	313,591
Capital Spending	151,520	193,264	519,521	521,818
Property and Land Acquisitions	13,344	1,702	18,280	16,366
Property Divestments	(168)	(762)	9,899	6,026
Net Debt to Adjusted Funds Flow Ratio[4]	0.7x	0.4x	0.7x	0.4x
Financial per Weighted Average Shares Outstanding				
Net Income - Basic	$ 0.28	$ 0.35	$ 0.72	$ 0.53
Net Income - Diluted	0.28	0.35	0.71	0.52
Weighted Average Number of Shares Outstanding (000's) - Basic	228,908	245,235	234,403	244,659
Weighted Average Number of Shares Outstanding (000's) - Diluted	231,529	250,957	237,399	250,048
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 40.75	$ 52.32	$ 43.02	$ 48.03
Royalties and Production Taxes	(10.80)	(13.39)	(10.86)	(12.03)
Commodity Derivative Instruments	0.53	(2.68)	0.54	(1.32)
Cash Operating Expenses	(7.06)	(6.80)	(7.83)	(7.01)
Transportation Costs	(3.96)	(3.70)	(3.97)	(3.60)
Cash General and Administrative Expenses	(1.19)	(1.35)	(1.32)	(1.49)
Cash Share-Based Compensation	—	0.02	(0.02)	(0.09)
Interest, Foreign Exchange and Other Expenses	(0.49)	(0.81)	(0.65)	(0.94)
Current Income Tax Recovery/(Expense)	—	(0.01)	0.72	(0.01)
Adjusted Funds Flow[4]	$ 17.78	$ 23.60	$ 19.63	$ 21.54

SELECTED OPERATING RESULTS	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Average Daily Production[2]				
Crude Oil (bbls/day)	55,023	48,867	48,141	43,892
Natural Gas Liquids (bbls/day)	5,098	4,563	4,736	4,487
Natural Gas (Mcf/day)	282,360	260,591	276,063	259,629
Total (BOE/day)	107,181	96,861	98,888	91,651
% Crude Oil and Natural Gas Liquids	56%	55%	53%	53%
Average Selling Price [2][3]				
Crude Oil (per bbl)	$ 67.76	$ 83.98	$ 69.64	$ 78.58
Natural Gas Liquids (per bbl)	5.97	25.95	13.97	28.85
Natural Gas (per Mcf)	2.13	3.22	3.00	3.14
Net Wells Drilled	17	17	47	49

(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 the effects of 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 September 30, 2019	2018	Nine months ended September 30, 2019	2018
WTI crude oil (US$/bbl)	$ 56.45	$ 69.50	$ 57.06	$ 66.75
Brent (ICE) crude oil (US$/bbl)	62.00	75.97	64.74	72.68
NYMEX natural gas – last day (US$/Mcf)	2.23	2.90	2.67	2.90
USD/CDN average exchange rate	1.32	1.31	1.33	1.29

Share Trading Summary For the three months ended September 30, 2019	CDN[1] - ERF (CDN$)	U.S.[2] - ERF (US$)
High	$ 11.16	$ 8.43
Low	$ 7.32	$ 5.50
Close	$ 9.87	$ 7.44

(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
Total	$ 0.09	$ 0.06

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

NEWS RELEASE

Highlights

- Third quarter total production was 107,181 BOE per day, up 6% quarter-over-quarter
- Third quarter liquids production was 60,121 barrels per day, up 14% quarter-over-quarter
- 2019 production guidance tightened to 100,000 to 101,000 BOE per day (from 99,000 to 102,000 BOE per day) with liquids production of 54,250 to 54,750 barrels per day (from 54,000 to 55,500 barrels per day)
- Third quarter capital spending was $151.5 million; 2019 capital spending guidance is now $625 million (from $610 to $630 million)
- Repurchased 7.1 million shares during the third quarter for $64.8 million
- Since initiating its share repurchase program, Enerplus has repurchased 24.2 million shares, or approximately 10% of shares outstanding
- Maintained strong financial flexibility; ended the third quarter with a net debt to adjusted funds flow ratio of 0.7 times

"In the third quarter of 2019, we continued to build on our track record of strong execution and financial discipline," stated Ian C. Dundas, President and Chief Executive Officer. "We grew our high-return production in North Dakota by 18% quarter-over-quarter, maintained our focus on costs, and returned over $70 million to shareholders through share repurchases and dividends. Year to date, we have now returned approximately $200 million to shareholders. Our 2019 plan remains on track to deliver 9 to 10% annual liquids production growth and 15% on a per share basis, while maintaining our low financial leverage."

Third Quarter Financial and Operational Summary

PRODUCTION

Production in the third quarter increased by 6% from the prior quarter to average 107,181 BOE per day, including oil and natural gas liquids production of 60,121 barrels per day, an increase of 14% from the prior quarter. The sequential production growth was driven by North Dakota volumes which increased 18% from the prior quarter. Natural gas production decreased 2% quarter-over-quarter, averaging 282 MMcf per day.

Capital activity in the fourth quarter is expected to be approximately 30% lower compared to the third quarter and will be primarily related to drilling in North Dakota. Enerplus expects modestly lower sequential production in the fourth quarter and is providing fourth quarter production guidance of 103,000 to 107,000 BOE per day with liquids production of 58,000 to 60,000 barrels per day.

ADJUSTED FUNDS FLOW AND ADJUSTED NET INCOME

Adjusted funds flow for the third quarter was $175.3 million compared to $186.0 million in the previous quarter. Third quarter 2019 adjusted net income was $61.9 million ($0.27 per share) compared to $74.3 million ($0.32 per share) in the previous quarter.

PRICING REALIZATION AND COST STRUCTURE

Enerplus' third quarter 2019 realized Bakken oil price differential was US$3.61 per barrel below WTI, 20% weaker compared to the prior quarter. With wider Bakken oil differentials expected to persist through the fourth quarter, Enerplus is revising its full-year Bakken differential guidance to US$3.60 per barrel below WTI (from US$3.25 per barrel below WTI). The Company continues to manage differential risk through fixed physical sales and in the fourth quarter has 24,800 barrels per day of Bakken oil production sold at US$2.69 per barrel below WTI.

The Company's realized Marcellus natural gas price differential averaged US$0.44 per Mcf below NYMEX during the third quarter, a 23% improvement from the prior quarter. Enerplus is maintaining its full-year 2019 Marcellus differential guidance at US$0.35 per Mcf below NYMEX.

Third quarter operating expenses were $7.06 per BOE, transportation expenses were $3.96 per BOE and cash G&A expenses were $1.19 per BOE. Combined, these expenses were 7% lower compared to the previous quarter. Enerplus is reducing its full-year 2019 guidance for cash G&A expenses to $1.40 per BOE (from $1.45 per BOE).

CAPITAL EXPENDITURES AND BALANCE SHEET POSITION

Exploration and development capital spending in the third quarter was $151.5 million and was associated with drilling 16.9 net wells and bringing 13.3 net wells on production across the Company's operations. Enerplus has revised its full-year 2019 capital spending guidance to $625 million (from $610 to $630 million).

At the end of the third quarter, Enerplus had total debt of $618.4 million, cash of $97.0 million and was undrawn on its $800 million bank credit facility. The Company's net debt to adjusted funds flow ratio was 0.7 times. Subsequent to the quarter, Enerplus renewed its bank credit facility to October 31, 2023 and amended it to a U.S. dollar denominated facility of US$600 million.

SHARE REPURCHASE

The Company repurchased 7.1 million shares during the third quarter for total consideration of $64.8 million. Subsequent to the quarter and up to November 6, 2019, the Company repurchased 2.7 million shares for a total consideration of $23.6 million and has now repurchased the maximum number of shares under its existing NCIB (7% of the public float within the meaning under the TSX rules). Enerplus today announced that its Board of Directors has approved an increase to the maximum number of shares that may be repurchased under the NCIB to 10% of the public float, representing an additional 7.1 million shares, until the expiry of its NCIB on March 25, 2020. Enerplus will continue to evaluate future share repurchases as a function of the value and returns underpinning the investment, alternative capital allocation opportunities and the Company's financial capacity.

Since initiating its share repurchase program in the third quarter of 2018 up to and including November 6, 2019, the Company has repurchased and cancelled 24.2 million shares, representing approximately 10% of shares outstanding, for total consideration of $257.8 million.

ASSET ACTIVITY

Average Daily Production[1]

	Three months ended September 30, 2019				Nine months ended September 30, 2019			
	Crude Oil (Mbbl/d)	NGL (Mbbl/d)	Natural Gas (MMcf/d)	Total (Mboe/d)	Crude Oil (Mbbl/d)	NGL (Mbbl/d)	Natural Gas (MMcf/d)	Total (Mboe/d)
Williston Basin	45.7	4.2	29.1	54.8	38.7	3.8	27.0	46.9
Marcellus	—	—	227.6	37.9	—	—	224.7	37.4
Canadian Waterfloods	8.4	0.1	3.8	9.2	8.6	0.1	3.6	9.3
Other[2]	0.8	0.8	21.9	5.3	0.9	0.9	20.8	5.3
Total	**55.0**	**5.1**	**282.4**	**107.2**	**48.1**	**4.7**	**276.1**	**98.9**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and non-core properties in Canada.

Summary of Wells Drilled[1]

	Three months ended September 30, 2019				Nine months ended September 30, 2019			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	17.0	14.9	4.0	1.6	43.0	37.2	7.0	2.7
Marcellus	—	—	6.0	0.4	—	—	23.0	0.9
Canadian Waterfloods	—	—	—	—	1.0	1.0	—	—
Other[2]	—	—	—	—	5.0	4.4	2.0	0.5
Total	**17.0**	**14.9**	**10.0**	**2.0**	**49.0**	**42.6**	**32.0**	**4.1**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and non-core properties in Canada.

Summary of Wells Brought On-Stream[1]

	Three months ended September 30, 2019				Nine months ended September 30, 2019			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	11.0	8.0	1.0	0.1	40.0	34.3	5.0	2.0
Marcellus	—	—	13.0	0.9	—	—	40.0	4.3
Canadian Waterfloods	—	—	—	—	1.0	1.0	—	—
Other[2]	5.0	4.4	—	—	5.0	4.4	2.0	0.5
Total	**16.0**	**12.4**	**14.0**	**0.9**	**46.0**	**39.7**	**47.0**	**6.8**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and non-core properties in Canada.

WILLISTON BASIN

Williston Basin production averaged 54,800 BOE per day (83% oil) during the third quarter of 2019, including 51,646 BOE per day in North Dakota (84% oil), an increase of 18% from the prior quarter. The Company drilled 17 gross operated wells (88% average working interest) and brought 11 gross operated wells (72% average working interest) on production during the third quarter.

MARCELLUS

Marcellus production averaged 228 MMcf per day during the third quarter, down 2% from the previous quarter. The Company participated in drilling six gross non-operated wells (6% average working interest) and brought 13 gross non-operated wells (7% average working interest) on production during the quarter.

DJ BASIN

Enerplus brought five gross operated wells (88% average working interest) on production in the third quarter in the DJ Basin. The Company continued to vary its completion design on these wells utilizing both higher and lower proppant and fluid intensities, aiming to further understand the associated well performance and cost structures. Enerplus is encouraged by the early stage production performance of the wells which are in line with the Company's expectations.

2019 Guidance Updates

The Company's updated guidance, with changes noted, is provided in the table below.

	Guidance
Capital spending	\$625 million (from \$610 to \$630 million)
Average annual production	100,000 to 101,000 BOE/day (from 99,000 to 102,000 BOE/day)
Average annual crude oil and natural gas liquids production	54,250 to 54,750 bbls/day (from 54,000 to 55,500 bbls/d)
Fourth quarter average production	103,000 to 107,000 BOE/day
Fourth quarter average crude oil and natural gas liquids production	58,000 to 60,000 bbls/day
Average royalty and production tax rate	25%
Operating expense	\$7.90/BOE
Transportation expense	\$4.00/BOE
Cash G&A expense	\$1.40/BOE (from \$1.45/BOE)

2019 Full-Year Differential/Basis Outlook[1]	
U.S. Bakken crude oil differential (compared to WTI crude oil)	US\$(3.60)/bbl (from US\$(3.25)/bbl)
Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US\$(0.35)/Mcf

(1) Excluding transportation costs.

Price Risk Management

Enerplus continues to manage price risk through commodity hedging. Enerplus has an average of 24,500 barrels per day of crude oil protected for the remainder of 2019 and 16,000 barrels per day protected in 2020.

For natural gas, Enerplus has entered into offsetting swaps through October 31, 2019, effectively locking in gains of US$0.51 per Mcf on the Company's original NYMEX hedges through this term.

Commodity Hedging Detail (As at November 6, 2019)

	WTI Crude Oil (US$/bbl)[1] Oct 1, 2019 – Dec 31, 2019	Jan 1, 2020 – Dec 31, 2020	NYMEX Natural Gas (US$/Mcf) Oct 1, 2019 – Oct 31, 2019
Swaps			
Sold Swaps	—	—	$ 2.85
Volume (bbls/d or Mcf/d)	—	—	90,000
Purchased Swaps	—	—	$ 2.34
Volume (bbls/d or Mcf/d)	—	—	90,000
Three Way Collars			
Sold Puts	$ 44.64	—	—
Volume (bbls/d or Mcf/d)	24,500	—	—
Purchased Puts	$ 54.81	—	—
Volume (bbls/d or Mcf/d)	24,500	—	—
Sold Calls	$ 65.99	—	—
Volume (bbls/d or Mcf/d)	24,500	—	—
Put Spreads			
Sold Puts	—	$ 46.88	—
Volume (bbls/d or Mcf/d)	—	16,000	—
Purchased Puts	—	$ 57.50	—
Volume (bbls/d or Mcf/d)	—	16,000	—

(1) The total average deferred premium on outstanding hedges is US$2.14/bbl from October 1, 2019 to December 31, 2020.

Currency and Accounting Principles
All amounts in this news release are stated in Canadian dollars unless otherwise specified. All financial information in this news release has been prepared and presented in accordance with U.S. GAAP, except as noted below under "Non-GAAP Measures".

Barrels of Oil Equivalent
This news release also contains references to "BOE" (barrels of oil equivalent). Enerplus has adopted the standard of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs. BOEs may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading.

Presentation of Production Information
Under U.S. GAAP oil and gas sales are generally presented net of royalties and U.S. industry protocol is to present production volumes net of royalties. Under Canadian industry protocol oil and gas sales and production volumes are presented on a gross basis before deduction of royalties. To continue to be comparable with its Canadian peer companies, the summary results contained within this news release presents Enerplus' production and BOE measures on a before royalty company interest basis. All production volumes and revenues presented herein are reported on a "company interest" basis, before deduction of Crown and other royalties, plus Enerplus' royalty interest.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This news release 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 news release contains forward-looking information pertaining to the following: expected fourth quarter and 2019 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; 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 2019 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; expected operating and transportation costs; our anticipated shares repurchases under *current and future normal course issuer bids; capital spending levels in 2019 and impact thereof on our production levels and land holdings; 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; 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; our future acquisitions and dispositions, expecting timing thereof and use of proceeds therefrom; and the amount of future cash dividends that we may pay to our shareholders.*

The forward-looking information contained in this news release 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 updated 2019 guidance contained in this news release is based on the rest of the year prices of: a WTI price of US$54.00/bbl, a NYMEX price of US$2.40/Mcf, and a USD/CDN exchange rate of 1.32. 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 news release 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 Annual Information Form, our Annual MD&A and Form 40-F as at December 31, 2018).

The forward-looking information contained in this news release speak only as of the date of this news release. Enerplus does not undertake any obligation to publicly update or revise any forward-looking information contained herein, except as required by applicable laws.

NON-GAAP MEASURES

In this news release, we use the terms "adjusted funds flow", "adjusted net income", "net debt to adjusted funds flow ratio" and "total debt net of cash" as measures to analyze operating performance, leverage and liquidity. "Adjusted funds flow" is calculated as cash flow generated from operating activities but before changes in non-cash operating working capital and asset retirement obligation expenditures. "Adjusted net income" is calculated as net income adjusted for unrealized derivative instrument gain/loss, unrealized foreign exchange gain/loss, the tax effect of these items and the impact of statutory changes to the Company's corporate tax rate. "Net debt to adjusted funds flow ratio" is calculated as total debt net of cash and cash equivalents, divided by a trailing 12 months of adjusted funds flow. "Total debt net of cash" is calculated as senior notes plus any outstanding bank credit facility balance, minus cash and cash equivalents. Calculation of these terms is described in Enerplus' MD&A under the "Non-GAAP Measures" section.

Enerplus believes that, in addition to net earnings and other measures prescribed by U.S. GAAP, the terms "adjusted funds flow", "adjusted net income", "net debt to adjusted funds flow", and "total debt net of cash" are useful supplemental measures as they provide an indication of the results generated by Enerplus' principal business activities. However, these measures are not measures recognized by U.S. GAAP and do not have a standardized meaning prescribed by U.S. GAAP. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers. For reconciliation of these measures to the most directly comparable measure calculated in accordance with U.S. GAAP, and further information about these measures, see disclosure under "Non-GAAP Measures" in Enerplus' Third Quarter 2019 MD&A.

Electronic copies of Enerplus Corporation's Third Quarter 2019 MD&A and Financial Statements, along with other public information including investor presentations, are available on its website at www.enerplus.com. Shareholders may, upon request, receive a printed copy of the Company's audited financial statements at any time. For further information, please contact Investor Relations at 1-800-319-6462 or email investorrelations@enerplus.com.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

The following discussion and analysis of financial results is dated November 7, 2019 and is to be read in conjunction with:

- the unaudited interim condensed consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three and nine months ended September 30, 2019 and 2018 (the "Interim Financial Statements");

- the audited consolidated financial statements of Enerplus as at December 31, 2018 and 2017 and for the years ended December 31, 2018, 2017 and 2016; and

- our MD&A for the year ended December 31, 2018 (the "Annual MD&A").

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 the MD&A for further information.

BASIS OF PRESENTATION

The Interim Financial Statements and Notes thereto have been prepared in accordance with U.S. GAAP, including the prior period comparatives. All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included in the Interim 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 bbl and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcf. BOE and Mcfe measures 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, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. Unless otherwise stated, 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. 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.

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

Effective January 1, 2019, Enerplus adopted ASC 842 - Leases. The most significant impact was the recognition of right-of-use ("ROU") assets and lease liabilities on the Condensed Consolidated Balance Sheet for operating leases and additional note disclosures. See Notes 3(a) and 10 to the Interim Financial Statements for further details.

OVERVIEW

Production for the third quarter averaged 107,181 BOE/day, an increase of 6% compared to second quarter production of 100,694 BOE/day. Crude oil and natural gas liquids production increased by 14% from the second quarter to 60,121 bbls/day with 8.1 net wells brought on stream in North Dakota and the full quarter impact of wells brought on stream near the end of the second quarter. We are narrowing our average annual production guidance range to 100,000 to 101,000 BOE/day from 99,000 to 102,000 BOE/day and narrowing our average annual crude oil and natural gas liquids guidance range to 54,250 to 54,750 bbls/day from 54,000 to 55,500 bbls/day. We are also providing additional fourth quarter average production guidance of 103,000 to 107,000 BOE/day and fourth quarter crude oil and natural gas liquids production guidance of 58,000 to 60,000 bbls/day.

During the third quarter, capital expenditures totaled $151.5 million, with approximately 90% of capital spending directed to U.S. crude oil properties in North Dakota and the DJ Basin. We expect total 2019 annual capital spending of $625 million, compared to the previous guidance range of $610 to $630 million. Capital activity for the remainder of the year will largely be focused on drilling in North Dakota.

Operating expenses and cash General & Administrative (“G&A”) expenses were in line with the prior quarter, at $69.6 million and $11.7 million, respectively. As a result of production growth, operating and G&A expenses decreased on a per BOE basis to $7.06/BOE and $1.19/BOE, respectively, compared to $7.84/BOE and $1.26/BOE, respectively, during the second quarter of 2019. We are maintaining our annual operating expense guidance of $7.90/BOE and reducing our annual cash G&A expense guidance to $1.40/BOE from $1.45/BOE.

Our Bakken crude oil price differential widened to US$3.61/bbl below WTI during the third quarter, compared to US$3.00/bbl below WTI in the second quarter of 2019, due to increasing production in the region. Accordingly, we are revising our full year U.S. Bakken crude oil differential outlook to US$3.60/bbl from US$3.25/bbl below WTI. We continue to expect a full year Marcellus natural gas sales price differential of US$0.35/Mcf below NYMEX.

As of November 6, 2019, we had approximately 66% of forecasted crude oil production, net of royalties, hedged for 2019, and approximately 43% of crude oil production, net of royalties, hedged in 2020, based on 2019 forecasted net production.

We reported net income of $65.2 million in the third quarter of 2019 compared to $85.1 million in the second quarter of 2019. The decrease was primarily the result of fluctuations in the USD/CDN foreign exchange rate, which resulted in a $7.1 million foreign exchange loss in the third quarter compared to a gain of $12.3 million in the second quarter of 2019.

During the third quarter of 2019, cash flow from operations decreased to $159.8 million, compared to $237.0 million in the second quarter of 2019, due to changes in working capital, most notably, the receipt of the first Alternative Minimum Tax (“AMT”) refund of $57.2 million in the second quarter of 2019. Adjusted funds flow in the third quarter decreased to $175.3 million from $186.0 million in the second quarter of 2019, primarily due to a current tax recovery of $13.9 million recorded in the second quarter.

During the quarter, we repurchased and cancelled 7,145,070 common shares under our Normal Course Issuer Bid (“NCIB”) for total consideration of $64.8 million.

At September 30, 2019, total debt net of cash was $521.4 million and our net debt to adjusted funds flow ratio was 0.7x.

RESULTS OF OPERATIONS

Production

Average daily production for the third quarter totaled 107,181 BOE/day, an increase of 6,487 BOE/day or 6% compared to second quarter production of 100,694 BOE/day. Crude oil and natural gas liquids production increased by 7,260 bbls/day or 14% from the second quarter to 60,121 bbls/day. We continued to see oil and natural gas liquids production growth in North Dakota, with 8.1 net wells coming on stream in the third quarter and a full quarter of production from the 24.7 net wells brought on stream in the second quarter. This was partially offset by the sale of certain Canadian assets with associated production of approximately 350 bbls/day in the second quarter. Natural gas production decreased 2% to 282,360 Mcf/day in the third quarter from 287,000 Mcf/day in the second quarter as a result of fewer wells brought on stream during the third quarter.

For the three and nine months ended September 30, 2019, total production increased by 10,320 BOE/day or 11%, and 7,237 BOE/day or 8%, respectively, when compared to the same periods in 2018. Production increased primarily due to our capital program in North Dakota and the DJ Basin, along with strong well performance in the Marcellus.

Our crude oil and natural gas liquids weighting increased to 56% in the third quarter of 2019 from 52% in the second quarter of 2019 and 55% in the third quarter of 2018.

Average daily production volumes for the three and nine months ended September 30, 2019 and 2018 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2019**	**2018**	**% Change**	**2019**	**2018**	**% Change**
Crude oil (bbls/day)	55,023	48,867	13%	48,141	43,892	10%
Natural gas liquids (bbls/day)	5,098	4,563	12%	4,736	4,487	6%
Natural gas (Mcf/day)	282,360	260,591	8%	276,063	259,629	6%
Total daily sales (BOE/day)	107,181	96,861	11%	98,888	91,651	8%

We are narrowing our average annual production guidance range to 100,000 to 101,000 BOE/day from 99,000 to 102,000 BOE/day and are narrowing our average annual crude oil and natural gas liquids guidance range to 54,250 to 54,750 bbls/day from 54,000 to 55,500 bbls/day. In addition, we expect fourth quarter average production of 103,000 to 107,000 BOE/day, including average crude oil and natural gas liquids production of 58,000 to 60,000 bbls/day.

Pricing

The prices received for crude oil and natural gas production directly impact our earnings, cash flow from operations, adjusted funds flow and financial condition. The following table compares quarterly average prices for the nine months ended September 30, 2019 and 2018 and other periods indicated:

Pricing (average for the period)	**Nine months ended September 30, 2019**	**2018**	**Q3 2019**	**Q2 2019**	**Q1 2019**	**Q4 2018**	**Q3 2018**
Benchmarks							
WTI crude oil (US$/bbl)	$ 57.06	$ 66.75	$ 56.45	$ 59.81	$ 54.90	$ 58.81	$ 69.50
Brent (ICE) crude oil (US$/bbl)	64.74	72.68	62.00	68.32	63.90	68.08	75.97
NYMEX natural gas – last day (US$/Mcf)	2.67	2.90	2.23	2.64	3.15	3.64	2.90
USD/CDN average exchange rate	1.33	1.29	1.32	1.34	1.33	1.32	1.31
USD/CDN period end exchange rate	1.32	1.29	1.32	1.31	1.33	1.36	1.29
Enerplus selling price[1]							
Crude oil ($/bbl)	$ 69.64	$ 78.58	$ 67.76	$ 74.42	$ 66.56	$ 64.18	$ 83.98
Natural gas liquids ($/bbl)	13.97	28.85	5.97	17.96	19.15	26.72	25.95
Natural gas ($/Mcf)	3.00	3.14	2.13	2.63	4.38	4.28	3.22
Average differentials							
Bakken DAPL – WTI (US$/bbl)	$ (2.75)	$ (1.90)	$ (2.97)	$ (2.36)	$ (2.93)	$ (9.22)	$ (0.97)
Brent (ICE) – WTI (US$/bbl)	7.68	5.93	5.55	8.51	9.00	9.27	6.47
MSW Edmonton – WTI (US$/bbl)	(4.71)	(6.06)	(4.66)	(4.63)	(4.85)	(26.30)	(6.83)
WCS Hardisty – WTI (US$/bbl)	(11.73)	(21.93)	(12.24)	(10.67)	(12.29)	(39.43)	(22.25)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.38)	(0.73)	(0.48)	(0.43)	(0.22)	(0.39)	(0.61)
Transco Z6 Non-New York monthly – NYMEX (US$/Mcf)	0.34	0.93	(0.35)	(0.31)	1.67	0.20	(0.12)
Enerplus realized differentials[1][2]							
Bakken crude oil – WTI (US$/bbl)	$ (3.30)	$ (3.03)	$ (3.61)	$ (3.00)	$ (3.25)	$ (5.60)	$ (2.54)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.31)	(0.46)	(0.44)	(0.57)	0.13	(0.34)	(0.48)
Canada crude oil – WTI (US$/bbl)	(11.28)	(17.86)	(13.50)	(9.99)	(10.42)	(33.27)	(16.61)

(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

Our realized crude oil sales price for the third quarter of 2019 averaged $67.76/bbl, a decrease of 9% compared to the second quarter of 2019. The decrease exceeded the change in WTI pricing, which was due to weakening Bakken and Canadian crude price differentials during the third quarter. Our realized Bakken crude oil differential weakened by US$0.61/bbl during the quarter to average US$3.61/bbl below WTI with increased production in the region pressuring in-basin pricing. Our Bakken sales price consists of a combination of in-basin monthly spot and index sales, term physical sales with fixed differential pricing versus WTI and/or Brent, and sales at the U.S. Gulf Coast delivered via firm capacity on the Dakota Access Pipeline. Bakken differentials began to weaken late in the third quarter and into the fourth quarter due to weaker Brent and WTI differentials in the Gulf Coast, as well as weaker spot prices resulting from higher than expected regional production growth in North Dakota. For the remainder of 2019, we have physical sales contracts in place for an average of 24,800 bbls/day of North Dakota crude oil production with fixed differentials averaging approximately US$2.69/bbl below WTI. Based on year to date price realizations and wider than expected fourth quarter Bakken differentials, we are revising our full year Bakken crude oil differential guidance to US$3.60/bbl below WTI from US$3.25/bbl.

Our realized price differential for Canadian crude oil production widened by US$3.51/bbl compared to the previous quarter, in response to a reduction in the production curtailments imposed by the Alberta government. We have fixed differential financial hedges in place for 1,500 bbls/day of Canadian heavy crude oil production at an average differential of US$14.83/bbl below WTI for the remainder of 2019.

Our realized price for natural gas liquids averaged $5.97/bbl during the third quarter, an $11.99/bbl decrease compared to the second quarter. Liquids pricing weakened further during the quarter as both local and North American butane and propane markets continue to remain oversupplied in 2019.

NATURAL GAS

Our average realized natural gas price during the third quarter of 2019 decreased by 19% compared to the second quarter of 2019 to average $2.13/Mcf, while NYMEX benchmark pricing decreased by 16%. Our realized Marcellus sales differential averaged US$0.44/Mcf below NYMEX during the third quarter. Pricing in U.S. Northeast markets was relatively weak during the quarter, particularly in September, after a cooler than normal summer allowed more gas to be injected into storage. Based on year to date realizations and our fourth quarter pricing outlook, we are maintaining our full year differential guidance for the Marcellus of US$0.35/Mcf below NYMEX.

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 weaker Canadian dollar increases 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 was weaker during the first nine months of 2019 with an average exchange rate of 1.33 USD/CDN compared to 1.29 USD/CDN for the same period in 2018. However, when compared to the exchange rate of 1.36 USD/CDN at December 31, 2018, the Canadian dollar strengthened relative to the U.S. dollar, closing the third quarter at 1.32 USD/CDN.

Price Risk Management

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

As of November 6, 2019, we have hedged 24,500 bbls/day of crude oil, which represents approximately 66% of our forecasted crude oil production, after royalties, for the remainder of 2019. For 2020, we have hedged 16,000 bbls/day, which represents approximately 43% of crude oil production, after royalties, based on our 2019 forecast. Our crude oil hedges in 2019 are all three-way collars which consist of a sold put, a purchased put and a sold call. Our crude oil hedges in 2020 are all put spreads with no cap on upside participation. With both three-way collars and put spreads, if WTI prices settle below the sold put strike price, these positions provide a limited amount of protection above the WTI settled price equal 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.

We have entered into offsetting purchase transactions on our NYMEX natural gas hedges through October 2019. This has effectively locked in gains of US$0.51/Mcf on our original NYMEX hedges through this term.

The following is a summary of our financial contracts in place at November 6, 2019, expressed as a percentage of our anticipated net production volumes:

	WTI Crude Oil (US$/bbl)[1]	
	Oct 1, 2019 – Dec 31, 2019	**Jan 1, 2020 – Dec 31, 2020**
Three Way Collars[2]		
Sold Puts	$ 44.64	—
%	66%	—
Purchased Puts	$ 54.81	—
%	66%	—
Sold Calls	$ 65.99	—
%	66%	—
Put Spreads[2]		
Sold Puts	—	$ 46.88
%	—	43%
Purchased Puts	—	$ 57.50
%	—	43%

(1) Based on weighted average price (before premiums) assuming average annual production of 100,500 BOE/day, which is the mid-point of our annual 2019 guidance, less royalties and production taxes of 25%. A portion of the sold puts are settled annually rather than monthly.

(2) The total average deferred premium on outstanding hedges is US$2.14/bbl from October 1, 2019 to December 31, 2020.

	NYMEX Natural Gas (US$/Mcf)[1]
	Oct 1, 2019 – Oct 31, 2019
Swaps	
Sold Swaps	$2.85
%	44%
Purchased Swaps	$2.34
%	44%

(1) Based on weighted average price (before premiums) assuming average annual production of 100,500 BOE/day, which is the mid-point of our annual 2019 guidance, less royalties and production taxes of 25%.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	**Three months ended September 30,**		**Nine months ended September 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Cash gains/(losses):				
Crude oil	$ (2.5)	$ (24.3)	$ (10.4)	$ (50.7)
Natural gas	7.7	0.4	25.0	17.7
Total cash gains/(losses)	$ 5.2	$ (23.9)	$ 14.6	$ (33.0)
Non-cash gains/(losses):				
Crude oil	$ 20.5	$ (30.0)	$ (42.8)	$ (130.8)
Natural gas	(5.5)	(0.2)	(9.1)	(1.7)
Total non-cash gains/(losses)	$ 15.0	$ (30.2)	$ (51.9)	$ (132.5)
Total gains/(losses)	$ 20.2	$ (54.1)	$ (37.3)	$ (165.5)

	Three months ended September 30,		**Nine months ended September 30,**	
(Per BOE)	**2019**	**2018**	**2019**	**2018**
Total cash gains/(losses)	$ 0.53	$ (2.68)	$ 0.54	$ (1.32)
Total non-cash gains/(losses)	1.52	(3.39)	(1.93)	(5.29)
Total gains/(losses)	$ 2.05	$ (6.07)	$ (1.39)	$ (6.61)

During the third quarter of 2019, we realized cash losses of $2.5 million on crude oil contracts and cash gains of $7.7 million on natural gas contracts. In comparison, during the third quarter of 2018, we realized cash losses of $24.3 million on crude oil contracts and cash gains of $0.4 million on natural gas contracts. Cash losses in the third quarter of 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. At September 30, 2019, the fair value of crude oil contracts was in a net asset position of $37.7 million and the fair value of our natural gas contracts was in a net asset position of $1.9 million. For the three and nine months ended September 30, 2019, the change in the fair value of our crude oil contracts resulted in a gain of $20.5 million and a loss of $42.8 million, respectively, and our natural gas contracts resulted in a loss of $5.5 million and $9.1 million, respectively.

Revenues

	Three months ended September 30,		**Nine months ended September 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Oil and natural gas sales	$ 401.8	$ 466.4	$ 1,161.4	$ 1,201.8
Royalties	(82.9)	(92.8)	(233.6)	(235.8)
Oil and natural gas sales, net of royalties	$ 318.9	$ 373.6	$ 927.8	$ 966.0

Oil and natural gas sales, net of royalties, for the three and nine months ended September 30, 2019, were $318.9 million and $927.8 million, respectively, a decrease of 15% and 4% from the same periods in 2018. The decrease in revenue during the three and nine months ended September 30, 2019 was a result of lower commodity prices, partially offset by higher production compared to the same periods in 2018.

Royalties and Production Taxes

($ millions, except per BOE amounts)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Royalties	$ 82.9	$ 92.8	$ 233.6	$ 235.8
Per BOE	$ 8.41	$ 10.41	$ 8.65	$ 9.42
Production taxes	$ 23.6	$ 26.6	$ 59.6	$ 65.4
Per BOE	$ 2.39	$ 2.98	$ 2.21	$ 2.61
Royalties and production taxes	$ 106.5	$ 119.4	$ 293.2	$ 301.2
Per BOE	$ 10.80	$ 13.39	$ 10.86	$ 12.03
Royalties and production taxes (% of oil and natural gas sales)	27%	26%	25%	25%

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. During the three and nine months ended September 30, 2019, royalties and production taxes decreased to $106.5 million and $293.2 million, respectively, from $119.4 million and $301.2 million for the same periods in 2018, primarily due to lower U.S. crude oil revenue.

We are maintaining our annual average royalty and production tax rate guidance of 25% for 2019.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Cash operating expenses	$ 69.6	$ 60.6	$ 211.3	$ 175.3
Non-cash (gains)/losses(1)	—	0.1	—	—
Total operating expenses	$ 69.6	$ 60.7	$ 211.3	$ 175.3
Per BOE	$ 7.06	$ 6.81	$ 7.83	$ 7.01

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

For the three and nine months ended September 30, 2019, operating expenses were $69.6 million or $7.06/BOE and $211.3 million or $7.83/BOE, respectively, representing an increase of $8.9 million and $36.0 million from the same periods in 2018. The increase is mainly attributable to higher North Dakota crude oil and natural gas liquids volumes, higher gas facility charges and well service activity in 2019.

We are maintaining our annual operating cost guidance of $7.90/BOE.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Transportation costs	$ 39.0	$ 33.0	$ 107.1	$ 90.1
Per BOE	$ 3.96	$ 3.70	$ 3.97	$ 3.60

For the three and nine months ended September 30, 2019, transportation costs were $39.0 million or $3.96/BOE and $107.1 million or $3.97/BOE, respectively. During the same periods in 2018, transportation costs were $33.0 million or $3.70/BOE and $90.1 million or $3.60/BOE. The increase is due to U.S. production growth and additional crude oil firm transportation commitments that commenced on March 1, 2019 and provide access to sell a portion of our North Dakota production at U.S. Gulf Coast or Brent pricing.

We are maintaining our annual guidance for transportation costs of $4.00/BOE.

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.

Netbacks by Property Type	Three months ended September 30, 2019 Crude Oil	Natural Gas	Total
Average Daily Production	64,455 BOE/day	256,356 Mcfe/day	107,181 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 58.69	$ 2.28	$ 40.75
Royalties and production taxes	(16.26)	(0.43)	(10.80)
Cash operating expenses	(10.70)	(0.26)	(7.06)
Transportation costs	(3.13)	(0.87)	(3.96)
Netback before hedging	$ 28.60	$ 0.72	$ 18.93
Cash hedging gains/(losses)	(0.42)	0.33	0.53
Netback after hedging	$ 28.18	$ 1.05	$ 19.46
Netback before hedging ($ millions)	$ 169.7	$ 17.0	$ 186.7
Netback after hedging ($ millions)	$ 167.2	$ 24.7	$ 191.9

Netbacks by Property Type	Three months ended September 30, 2018 Crude Oil	Natural Gas	Total
Average Daily Production	57,244 BOE/day	237,702 Mcfe/day	96,861 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 75.33	$ 3.19	$ 52.32
Royalties and production taxes	(20.16)	(0.60)	(13.39)
Cash operating expenses	(10.05)	(0.35)	(6.80)
Transportation costs	(2.50)	(0.91)	(3.70)
Netback before hedging	$ 42.62	$ 1.33	$ 28.43
Cash hedging gains/(losses)	(4.60)	0.02	(2.68)
Netback after hedging	$ 38.02	$ 1.35	$ 25.75
Netback before hedging ($ millions)	$ 224.5	$ 28.9	$ 253.4
Netback after hedging ($ millions)	$ 200.2	$ 29.3	$ 229.5

Netbacks by Property Type	Nine months ended September 30, 2019 Crude Oil	Natural Gas	Total
Average Daily Production	56,705 BOE/day	253,097 Mcfe/day	98,888 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 61.13	$ 3.11	$ 43.02
Royalties and production taxes	(16.29)	(0.59)	(10.86)
Cash operating expenses	(12.24)	(0.32)	(7.83)
Transportation costs	(2.98)	(0.88)	(3.97)
Netback before hedging	$ 29.62	$ 1.32	$ 20.36
Cash hedging gains/(losses)	(0.67)	0.36	0.54
Netback after hedging	$ 28.95	$ 1.68	$ 20.90
Netback before hedging ($ millions)	$ 458.4	$ 91.4	$ 549.8
Netback after hedging ($ millions)	$ 448.0	$ 116.4	$ 564.4

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

Netbacks by Property Type	Nine months ended September 30, 2018 Crude Oil	Natural Gas	Total
Average Daily Production	51,623 BOE/day	240,168 Mcfe/day	91,651 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 70.67	$ 3.14	$ 48.03
Royalties and production taxes	(18.63)	(0.59)	(12.03)
Cash operating expenses	(10.65)	(0.39)	(7.01)
Transportation costs	(2.35)	(0.87)	(3.60)
Netback before hedging	$ 39.04	$ 1.29	$ 25.39
Cash hedging gains/(losses)	(3.60)	0.27	(1.32)
Netback after hedging	$ 35.44	$ 1.56	$ 24.07
Netback before hedging ($ millions)	$ 550.1	$ 85.1	$ 635.2
Netback after hedging ($ millions)	$ 499.4	$ 102.8	$ 602.2

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

Total netbacks before hedging for the three and nine months ended September 30, 2019 were lower compared to the same periods in 2018 primarily due to weaker realized prices, increased cash operating expenses and increased transportation.

For the three and nine months ended September 30, 2019, our crude oil properties accounted for 91% and 83% of our total netback before hedging, respectively, compared to 89% and 87% during the same periods in 2018.

General and Administrative (“G&A”) Expenses

Total G&A expenses include share-based compensation (“SBC”) charges related to our long-term incentive plans (“LTI plans”). See Note 12 and Note 15 to the Interim Financial Statements for further details.

($ millions)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Cash:				
G&A expense	$ 11.7	$ 12.0	$ 35.5	$ 37.3
Share-based compensation expense	0.1	(0.2)	0.8	2.2
Non-Cash:				
Share-based compensation expense	4.7	4.3	17.0	18.4
Equity swap loss/(gain)	—	0.2	0.1	(1.2)
G&A expense	0.2	—	0.6	—
Total G&A expenses	$ 16.7	$ 16.3	$ 54.0	$ 56.7

(Per BOE)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Cash:				
G&A expense	$ 1.19	$ 1.35	$ 1.32	$ 1.49
Share-based compensation expense	—	(0.02)	0.02	0.09
Non-Cash:				
Share-based compensation expense	0.48	0.48	0.63	0.74
Equity swap loss/(gain)	—	0.02	0.01	(0.05)
G&A expense	0.02	—	0.02	—
Total G&A expenses	$ 1.69	$ 1.83	$ 2.00	$ 2.27

For the three and nine months ended September 30, 2019, cash G&A expense was $11.7 million or $1.19/BOE and $35.5 million or $1.32/BOE, respectively, compared to $12.0 million or $1.35/BOE and $37.3 million or $1.49/BOE for the same periods in 2018. While total cash G&A expenses decreased, the more significant per BOE decrease was due to higher production when compared to the same periods in 2018.

During the third quarter of 2019, we reported a cash SBC expense of $0.1 million due to an increase in our share price on outstanding deferred share units. In comparison, during the same period of 2018, we recorded a cash SBC recovery of $0.2 million due to a decrease in our share price on outstanding deferred share units. In the third quarter of 2019, we recorded a non-cash SBC expense of $4.7 million or $0.48/BOE, consistent with $4.3 million or $0.48/BOE during the same period in 2018.

We have hedges in place on a portion of the outstanding cash-settled grants under our LTI plans. Due to minimal share price movement over the third quarter of 2019, we recorded no mark-to-market gain or loss, compared to a loss of $0.2 million in the same period in 2018. At September 30, 2019, we had 264,000 units outstanding, hedged at a weighted average price of $17.82 per share.

Based on year-to-date spending, we are reducing our annual cash G&A guidance of $1.45/BOE to $1.40/BOE.

Interest Expense

For the three and nine months ended September 30, 2019, we recorded total interest expense of $7.9 million and $25.0 million, respectively, compared to $8.6 million and $27.0 million for the same periods in 2018. The decrease in interest expense for the nine months ended September 30, 2019 compared to the same period in 2018 was primarily due to the repayment of a portion of 2009 senior notes which carry a higher coupon rate compared to the remaining senior notes outstanding.

At September 30, 2019, we were undrawn on our bank credit facility and our debt balance consisted of fixed interest rate senior notes with a weighted average interest rate of 4.7%. See Note 8 to the Interim Financial Statements for further details.

Foreign Exchange

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2019	2018	2019	2018
Realized:				
Foreign exchange (gain)/loss on settlements	$ —	$ 0.3	$ —	$ 0.6
Translation of U.S. dollar cash held in Canada (gain)/loss	(1.5)	4.3	7.9	(6.8)
Unrealized (gain)/loss	8.6	(12.2)	(25.0)	17.9
Total foreign exchange (gain)/loss	$ 7.1	$ (7.6)	$ (17.1)	$ 11.7
USD/CDN average exchange rate	1.32	1.31	1.33	1.29
USD/CDN period end exchange rate	1.32	1.29	1.32	1.29

For the three and nine months ended September 30, 2019, we recorded a foreign exchange loss of $7.1 million and a gain of $17.1 million, respectively, compared to a gain of $7.6 million and a loss of $11.7 million for the same periods in 2018. Realized gains and losses relate primarily to day-to-day transactions recorded in foreign currencies, along with the translation of U.S. dollar denominated cash held in Canada, while unrealized gains and losses are recorded on the translation of U.S. dollar denominated debt and working capital at each period end. Comparing the period end exchange rate at September 30, 2019 to December 31, 2018, the Canadian dollar strengthened relative to the U.S. dollar, resulting in an unrealized gain of $25.0 million. See Note 13 to the Interim Financial Statements for further details.

Capital Investment

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2019	2018	2019	2018
Capital spending(1)	$ 151.5	$ 193.3	$ 519.5	$ 521.8
Office capital(1)	2.9	1.6	6.1	5.3
Line fill	—	—	5.1	—
Sub-total	154.4	194.9	530.7	527.1
Property and land acquisitions	$ 13.3	$ 1.7	$ 18.3	$ 16.4
Property divestments	0.2	0.8	(9.9)	(6.0)
Sub-total	13.5	2.5	8.4	10.4
Total	$ 167.9	$ 197.4	$ 539.1	$ 537.5

(1) Excludes changes in non-cash investing working capital. See Note 18(b) to the Interim Financial Statements for further details.

Capital spending for the three and nine months ended September 30, 2019 totaled $151.5 million and $519.5 million, respectively, compared to $193.3 million and $521.8 million for the same periods in 2018. The decrease in spending was due to lower completions activity in the third quarter of 2019 compared to the same period in 2018. During the third quarter of 2019, we invested $136.2 million in U.S. crude oil properties, $9.5 million in Marcellus natural gas assets and $6.2 million in Canadian waterflood properties. During the nine months ended September 30, 2019, we spent $5.1 million on line fill to meet the requirements of a multi-year transportation contract, which began in March 2019.

In the third quarter of 2019, we completed $13.3 million in property and land acquisitions, which consisted primarily of undeveloped land in North Dakota, compared to $1.7 million for the same period in 2018. Property divestments for the nine months ended September 30, 2019 were $9.9 million, which primarily related to the divestment of properties in Southeastern Saskatchewan with associated production of approximately 350 bbls/day.

We are revising our 2019 annual capital spending guidance to $625 million from $610 million to $630 million.

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

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2019	2018	2019	2018
DD&A expense	$ 94.4	$ 81.5	$ 258.6	$ 218.7
Per BOE	$ 9.57	$ 9.15	$ 9.58	$ 8.74

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three and nine months ended September 30, 2019, DD&A increased to $94.4 million and $258.6 million, respectively, compared to $81.5 million and $218.7 million for the same periods in 2018. The increase in DD&A was a result of additional U.S. production with higher depletion rates combined with the impact of a weaker Canadian dollar on U.S. DD&A expense.

Impairment

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country basis using estimated after-tax future net cash flows discounted at 10 percent from proved reserves using SEC constant prices ("Standardized Measure"). 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 affect DD&A expense. At September 30, 2019, SEC prices were above current commodity price levels. If commodity prices remain at current levels or decline further, SEC prices will be impacted. There have been no impairments recorded in the current or prior year. See Note 6 to the Interim Financial Statements for trailing twelve month prices.

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, using a weighted average credit-adjusted risk-free rate of 5.53%, to be $130.2 million at September 30, 2019, compared to 5.59% and $126.1 million at December 31, 2018. For the three and nine months ended September 30, 2019, asset retirement obligation settlements were $2.9 million and $8.8 million, respectively, compared to $2.8 million and $8.1 million during the same periods in 2018. See Note 9 to the Interim Financial Statements for further details.

Leases

On January 1, 2019, we adopted ASU 842 – *Leases*, which requires the recognition of ROU assets and lease liabilities on the Condensed 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 September 30, 2019, our total lease liability was $57.7 million. In addition, ROU assets of $53.5 million were recorded, which equate to our lease liabilities less lease incentives. See Note 3(a) and Note 10 to the Interim Financial Statements for further details.

Income Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2019	2018	2019	2018
Current tax expense/(recovery)	$ —	$ 0.1	$ (19.5)	$ 0.2
Deferred tax expenses/(recovery)	18.6	15.0	49.5	30.7
Total tax expense/(recovery)	$ 18.6	$ 15.1	$ 30.0	$ 30.9

For the three and nine months ended September 30, 2019, we recorded a current tax recovery of nil and $19.5 million, respectively, compared to an expense of $0.1 million and $0.2 million for the same periods in 2018. The recovery in 2019 relates primarily to the favorable settlement of a tax dispute in Canada in the second quarter of 2019 and the reversal of the reserve recorded at December 31, 2017 for the sequestered portion of our U.S. AMT refund in the first quarter of 2019.

For the three and nine months ended September 30, 2019, we recorded a deferred tax expense of $18.6 million and $49.5 million, respectively, compared to $15.0 million and $30.7 million for the same periods in 2018. The increase in deferred tax expense in 2019 is primarily due to an expense recorded in the second quarter of 2019 for the remeasurement of our Canadian net deferred income tax asset to account for the change in the Alberta corporate income tax rate from 12% to 8% by 2022. See Note 14 to the Interim Financial Statements for further details.

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess 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 under our bank credit facility and senior notes, 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. At September 30, 2019, our senior debt to adjusted EBITDA ratio was 0.9x and our net debt to adjusted funds flow ratio was 0.7x. 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 liquidity.

Total debt net of cash at September 30, 2019 was $521.4 million, an increase of 56% compared to $333.5 million at December 31, 2018. The increase is primarily due to the use of cash on hand for the repurchase and cancellation of approximately 15.5 million common shares during the nine months ended September 30, 2019, for total consideration of $155.1 million. Total debt was comprised of $618.4 million of senior notes less $97.0 million in cash.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, was 92% and 104% for the three and nine months ended September 30, 2019, respectively, compared to 96% and 102% for the same periods in 2018.

Our working capital deficiency, excluding cash and current derivative financial assets and liabilities, increased to $178.0 million at September 30, 2019 from $143.1 million at December 31, 2018. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, cash flow from operations and our bank credit facility. We have sufficient liquidity to meet our financial commitments, as disclosed under "Commitments" in the Annual MD&A.

Subsequent to the 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 other significant amendments or additions to the agreement terms or covenants. Drawn fees on the 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 September 30, 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 under our SEDAR profile at www.sedar.com.

The following table lists our financial covenants as at September 30, 2019:

Covenant Description		September 30, 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%	17%
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%	18%
	Minimum Ratio	
Adjusted EBITDA to interest [(1)]	4.0x	21.2x

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, impairment 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 September 30, 2019 was $184.7 million and $737.4 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%.

Dividends

($ millions, except per share amounts)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Dividends to shareholders[(1)]	$ 6.8	$ 7.4	$ 21.0	$ 22.0
Per weighted average share (Basic)	$ 0.03	$ 0.03	$ 0.09	$ 0.09

(1) Excludes changes in non-cash financing working capital. See Note 18(b) to the Interim Financial Statements for further details.

During the three and nine months ended September 30, 2019, we reported total dividends of $6.8 million or $0.03 per share and $21.0 million or $0.09 per share, respectively, compared to $7.4 million or $0.03 per share and $22.0 million or $0.09 per share for the same periods in 2018. Dividends to shareholders have decreased compared to the same periods in 2018 as a result of our share repurchase program.

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

Shareholders' Capital

	Nine months ended September 30, 2019	2018
Share capital ($ millions)	$ 3,126.1	$ 3,412.2
Common shares outstanding (thousands)	224,471	244,764
Weighted average shares outstanding – basic (thousands)	234,403	244,659
Weighted average shares outstanding – diluted (thousands)	237,399	250,048

For the nine months ended September 30, 2019, a total of 1,007,234 units vested pursuant to our treasury settled LTI plans (2018 – 2,539,498). In total, 564,000 shares were issued from treasury and $4.4 million was transferred from paid-in capital to share capital (2018 – 2,539,498; $23.4 million). We elected to cash settle the remaining units related to the required tax withholdings (2019 – $5.0 million, 2018 – nil).

For the nine months ended September 30, 2019, no shares were issued pursuant to our stock option plan, resulting in no additional share capital (2018 – 640,086; $8.7 million).

On March 21, 2019, Enerplus announced the renewal of its NCIB to purchase up to 16,673,015 common shares, representing 7% of the "public float" of Enerplus (within the meaning under the rules of the Toronto Stock Exchange (the "TSX")) through the facilities of the TSX, the New York Stock Exchange and/or alternative Canadian trading systems during the 12-month period ending March 25, 2020. 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 public float (or an additional 7,145,578 common shares) until the expiry of the NCIB on March 25, 2020, subject to TSX approval.

During the nine months ended September 30, 2019, the Company repurchased 15,503,891 common shares under the previous and current NCIB at an average price of $10.00 per share, for total consideration of $155.1 million (2018 – 544,300; $8.5 million). Of the amount paid, $215.9 million was charged to share capital and $60.8 million was credited to accumulated deficit (2018 – $7.6 million; charge of $0.9 million). Subsequent to the quarter and up to November 6, 2019, the Company repurchased 2,727,510 common shares under the NCIB at an average price of $8.66 per share, for total consideration of $23.6 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 November 6, 2019, we had 221,743,701 common shares outstanding. In addition, an aggregate of 7,931,999 common shares may be issued to settle outstanding grants under the Performance Share Unit ("PSU"), Restricted Share Unit, and stock option plans, assuming the maximum payout multiplier of 2.0 times for the PSUs.

For further details, see Note 15 to the Interim Financial Statements.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

($ millions, except per unit amounts)	Three months ended September 30, 2019 Canada	U.S.	Total	Three months ended September 30, 2018 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	8,614	46,409	55,023	9,170	39,697	48,867
Natural gas liquids (bbls/day)	873	4,225	5,098	1,002	3,561	4,563
Natural gas (Mcf/day)	25,699	256,661	282,360	24,486	236,105	260,591
Total average daily production (BOE/day)	13,770	93,411	107,181	14,253	82,608	96,861
Pricing[2]						
Crude oil (per bbl)	$ 56.71	$ 69.82	$ 67.76	$ 69.12	$ 87.42	$ 83.98
Natural gas liquids (per bbl)	24.92	2.06	5.97	45.44	20.47	25.95
Natural gas (per Mcf)	0.79	2.26	2.13	2.78	3.27	3.22
Capital Expenditures						
Capital spending	$ 5.9	$ 145.6	$ 151.5	$ 15.3	$ 178.0	$ 193.3
Acquisitions	0.8	12.5	13.3	0.9	0.8	1.7
Divestments	0.2	—	0.2	1.1	(0.3)	0.8
Netback[3] Before Hedging						
Oil and natural gas sales	$ 49.5	$ 352.3	$ 401.8	$ 69.4	$ 397.0	$ 466.4
Royalties	(10.7)	(72.2)	(82.9)	(13.4)	(79.4)	(92.8)
Production taxes	(1.0)	(22.6)	(23.6)	(1.1)	(25.5)	(26.6)
Cash operating expenses	(15.4)	(54.2)	(69.6)	(19.1)	(41.5)	(60.6)
Transportation costs	(2.6)	(36.4)	(39.0)	(2.9)	(30.1)	(33.0)
Netback before hedging	$ 19.8	$ 166.9	$ 186.7	$ 32.9	$ 220.5	$ 253.4
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (20.2)	$ —	$ (20.2)	$ 54.1	$ —	$ 54.1
Total G&A[4]	9.0	7.7	16.7	9.9	6.4	16.3
Current income tax expense/(recovery)	—	—	—	(0.4)	0.5	0.1

($ millions, except per unit amounts)	Nine months ended September 30, 2019 Canada	U.S.	Total	Nine months ended September 30, 2018 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	8,786	39,355	48,141	9,297	34,595	43,892
Natural gas liquids (bbls/day)	929	3,807	4,736	1,100	3,387	4,487
Natural gas (Mcf/day)	24,394	251,669	276,063	28,891	230,738	259,629
Total average daily production (BOE/day)	13,781	85,107	98,888	15,213	76,438	91,651
Pricing[2]						
Crude oil (per bbl)	$ 60.96	$ 71.58	$ 69.64	$ 62.78	$ 82.83	$ 78.58
Natural gas liquids (per bbl)	28.88	10.34	13.97	46.84	23.00	28.85
Natural gas (per Mcf)	2.38	3.06	3.00	2.67	3.19	3.14
Capital Expenditures						
Capital spending	$ 30.4	$ 489.1	$ 519.5	$ 39.8	$ 482.0	$ 521.8
Acquisitions	2.9	15.4	18.3	3.0	13.4	16.4
Divestments	(9.3)	(0.6)	(9.9)	0.3	(6.3)	(6.0)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 171.4	$ 990.0	$ 1,161.4	$ 197.0	$ 1,004.8	$ 1,201.8
Royalties	(32.3)	(201.3)	(233.6)	(34.2)	(201.6)	(235.8)
Production taxes	(1.9)	(57.7)	(59.6)	(2.6)	(62.8)	(65.4)
Cash operating expenses	(54.0)	(157.3)	(211.3)	(57.3)	(118.0)	(175.3)
Transportation costs	(7.9)	(99.2)	(107.1)	(8.8)	(81.3)	(90.1)
Netback before hedging	$ 75.3	$ 474.5	$ 549.8	$ 94.1	$ 541.1	$ 635.2
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 37.3	$ —	$ 37.3	$ 165.5	$ —	$ 165.5
Total G&A[4]	20.2	33.8	54.0	31.6	25.1	56.7
Current income tax expense/(recovery)	(13.9)	(5.5)	(19.4)	(0.4)	0.6	0.2

(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 expense.

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				
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	$ 927.8	$ 169.4	$ 0.72	$ 0.71
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
2017				
Fourth Quarter	$ 271.1	$ 15.3	$ 0.06	$ 0.06
Third Quarter	196.1	16.1	0.07	0.07
Second Quarter	225.7	129.3	0.53	0.52
First Quarter	227.8	76.3	0.32	0.31
Total 2017	$ 920.7	$ 237.0	$ 0.98	$ 0.96

Oil and natural gas sales, net of royalties, and net income for the third quarter were in line with the second quarter of 2019. From the first quarter of 2019 to the second quarter of 2019, oil and natural gas sales, net of royalties, increased by $34.0 million due to increased production. Second quarter net income included a $27.4 million gain on commodity derivative instruments, compared to a loss of $84.9 million in the first quarter of 2019.

Oil and natural gas sales, net of royalties, increased in 2018 compared to 2017 due to an increase in realized commodity prices and a higher weighting of crude oil and natural gas liquids production. As a result, net income also improved in 2018, excluding the effects of a gain which was recorded on asset divestments in the second quarter of 2017.

2019 UPDATED GUIDANCE

We are narrowing our average annual production guidance range to 100,000 to 101,000 BOE/day from 99,000 to 102,000 BOE/day and narrowing our average annual crude oil and natural gas liquids guidance to 54,250 to 54,750 bbls/day from 54,000 to 55,500 bbls/day. In addition, we are providing fourth quarter average production guidance of 103,000 to 107,000 BOE/day, including average crude oil and natural gas liquids production of 58,000 to 60,000 bbls/day.

We are revising our 2019 capital spending guidance to $625 million from our previous range of $610 to $630 million and we are reducing our annual cash G&A guidance to $1.40/BOE from $1.45/BOE.

We are modifying our full year Bakken differential guidance to US$3.60/bbl below WTI from US$3.25/bbl.

All other guidance targets remain unchanged. This guidance does not include any additional acquisitions or divestments.

Summary of 2019 Expectations	Target
Capital spending	$625 million (from $610 - $630 million)
Average annual production	100,000 - 101,000 BOE/day (from 99,000 - 102,000 BOE/day)
Average annual crude oil and natural gas liquids production	54,250 - 54,750 bbls/day (from 54,000 - 55,500 bbls/day)
Fourth quarter average production	103,000 - 107,000 BOE/day
Fourth quarter average crude oil and natural gas liquids production	58,000 - 60,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	25%
Operating expenses	$7.90/BOE
Transportation costs	$4.00/BOE
Cash G&A expenses	$1.40/BOE (from $1.45/BOE)

2019 Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.60)/bbl (from US$(3.25)/bbl)
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.35)/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 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	**Three months ended September 30,**		**Nine months ended September 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Oil and natural gas sales	$ 401.8	$ 466.4	$ 1,161.4	$ 1,201.8
Less:				
Royalties	(82.9)	(92.8)	(233.6)	(235.8)
Production taxes	(23.6)	(26.6)	(59.6)	(65.4)
Cash operating expenses[1]	(69.6)	(60.6)	(211.3)	(175.3)
Transportation costs	(39.0)	(33.0)	(107.1)	(90.1)
Netback before hedging	$ 186.7	$ 253.4	$ 549.8	$ 635.2
Cash gains/(losses) on derivative instruments	5.2	(23.9)	14.6	(33.0)
Netback after hedging	$ 191.9	$ 229.5	$ 564.4	$ 602.2

(1) Cash operating expenses have been adjusted to exclude a non-cash loss of $0.1 million and nil for the three and nine months ended September 30, 2018, respectively.

"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	**Three months ended September 30,**		**Nine months ended September 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Cash flow from operating activities	$ 159.8	$ 216.1	$ 505.8	$ 517.2
Asset retirement obligation expenditures	2.9	2.8	8.8	8.1
Changes in non-cash operating working capital	12.6	(8.5)	15.5	13.9
Adjusted funds flow	$ 175.3	$ 210.4	$ 530.1	$ 539.2

"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	**Three months ended September 30,**		**Nine months ended September 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Adjusted funds flow	$ 175.3	$ 210.4	$ 530.1	$ 539.2
Capital spending	(151.5)	(193.3)	(519.5)	(521.8)
Free cash flow	$ 23.8	$ 17.1	$ 10.6	$ 17.4

"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, unrealized foreign exchange gain/loss, the tax effect of these items and the impact of statutory changes to the Company's corporate tax rate.

Calculation of Adjusted Net Income	**Three months ended September 30,**		**Nine months ended September 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Net income/(loss)	$ 65.1	$ 86.9	$ 169.4	$ 129.0
Unrealized derivative instrument (gain)/loss	(14.9)	30.4	52.0	131.2
Unrealized foreign exchange (gain)/loss	8.6	(12.2)	(25.0)	17.9
Tax effect on above items	3.1	(7.9)	(14.0)	(35.4)
Income tax rate adjustment on deferred taxes	—	—	26.3	—
Adjusted net income	$ 61.9	$ 97.2	$ 208.7	$ 242.7

"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, 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 adjusted payout ratio as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow.

Calculation of Adjusted Payout Ratio	**Three months ended September 30,**		**Nine months ended September 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Dividends	$ 6.8	$ 7.4	$ 21.0	$ 22.0
Capital, office expenditures and line fill	154.4	194.9	530.7	527.1
Sub-total	$ 161.2	$ 202.3	$ 551.7	$ 549.1
Adjusted funds flow	$ 175.3	$ 210.4	$ 530.1	$ 539.2
Adjusted payout ratio (%)	92%	96%	104%	102%

“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)	**September 30, 2019**
Net income/(loss)	$ 418.7
Add:	
Interest	34.8
Current and deferred tax expense/(recovery)	102.3
DD&A and asset impairment	344.2
Other non-cash charges(2)	(162.6)
Adjusted EBITDA	$ 737.4

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at September 30, 2019 include the nine months ended September 30, 2019 and the fourth quarter of 2018.
(2) Includes the change in fair value of commodity derivatives and equity swaps, non-cash SBC expense, non-cash G&A expense and unrealized foreign exchange gains/losses.

In addition, the Company uses certain financial measures within the “Liquidity and Capital Resources” section 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 control 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 Issuer’s Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at September 30, 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 July 1, 2019 and ended September 30, 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 (“AIF”), 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 fourth quarter and 2019 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; 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 2019 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; expected operating and transportation costs; our anticipated shares repurchases under current and future normal course issuer bids; capital spending levels in 2019 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 future acquisitions and dispositions, expecting timing thereof and use of proceeds therefrom; and the amount of future cash dividends that we may pay to our shareholders.*

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 updated 2019 guidance contained in this MD&A is based on the rest of the year prices of: a WTI price of US$54.00/bbl, a NYMEX price of US$2.40/Mcf, and a USD/CDN exchange rate of 1.32. 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 Annual Information Form, our Annual MD&A and Form 40-F as at December 31, 2018).

The forward-looking information contained in this MD&A speak only as of the date of this MD&A. Enerplus does not undertake any obligation to publicly update or revise any forward-looking information contained herein, except as required by applicable laws.

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	September 30, 2019	December 31, 2018
Assets			
Current Assets			
Cash and cash equivalents		$ 96,976	$ 363,327
Accounts receivable	4	174,100	145,206
Income tax receivable	14	30,677	55,172
Derivative financial assets	16	45,853	59,258
Other current assets		11,634	8,928
		359,240	631,891
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	5	1,547,525	1,293,941
Other capital assets, net	5	21,661	13,130
Property, plant and equipment		1,569,186	1,307,071
Right-of-use assets	3,10	53,476	—
Goodwill		648,885	654,799
Derivative financial assets	16	875	32,220
Deferred income tax asset	14	407,974	465,124
Income tax receivable	14	—	27,195
Total Assets		$ 3,039,636	$ 3,118,300
Liabilities			
Current liabilities			
Accounts payable	7	$ 266,652	$ 290,045
Dividends payable		2,247	2,395
Current portion of long-term debt	8	108,047	60,001
Derivative financial liabilities	16	2,069	1,909
Current portion of lease liabilities	3,10	17,460	—
		396,475	354,350
Derivative financial liabilities	16	7,123	—
Long-term debt	8	510,308	636,849
Asset retirement obligation	9	130,184	126,112
Lease liabilities	3,10	40,282	—
		687,897	762,961
Total Liabilities		1,084,372	1,117,311
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: September 30, 2019 – 224 million shares			
December 31, 2018 – 239 million shares	15	3,126,078	3,337,608
Paid-in capital		54,175	46,524
Accumulated deficit		(1,562,913)	(1,772,084)
Accumulated other comprehensive income/(loss)		337,924	388,941
		1,955,264	2,000,989
Total Liabilities & Shareholders' Equity		$ 3,039,636	$ 3,118,300
Commitments and Contingencies	17		
Subsequent events	8, 15		

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

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

(CDN$ thousands, except per share amounts) unaudited	Note	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Revenues					
Oil and natural gas sales, net of royalties	11	$ 318,849	$ 373,577	$ 927,764	$ 965,981
Commodity derivative instruments gain/(loss)	16	20,187	(54,054)	(37,258)	(165,469)
		339,036	319,523	890,506	800,512
Expenses					
Operating		69,639	60,709	211,250	175,349
Transportation		39,019	33,013	107,113	90,057
Production taxes		23,581	26,583	59,638	65,367
General and administrative	12	16,651	16,291	54,041	56,704
Depletion, depreciation and accretion		94,423	81,509	258,649	218,720
Interest		7,912	8,601	24,998	26,953
Foreign exchange (gain)/loss	13	7,135	(7,596)	(17,142)	11,686
Other expense/(income)		(3,101)	(1,631)	(7,531)	(4,261)
		255,259	217,479	691,016	640,575
Income/(Loss) before taxes		83,777	102,044	199,490	159,937
Current income tax expense/(recovery)	14	26	92	(19,432)	230
Deferred income tax expense/(recovery)	14	18,570	15,029	49,499	30,743
Net Income/(Loss)		$ 65,181	$ 86,923	$ 169,423	$ 128,964
Other Comprehensive Income/(Loss)					
Change in cumulative translation adjustment		19,547	(26,743)	(51,017)	35,615
Total Comprehensive Income/(Loss)		$ 84,728	$ 60,180	$ 118,406	$ 164,579
Net income/(Loss) per share					
Basic	15	$ 0.28	$ 0.35	$ 0.72	$ 0.53
Diluted	15	$ 0.28	$ 0.35	$ 0.71	$ 0.52

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

Condensed Consolidated Statements of Changes in Shareholders' Equity

(CDN$ thousands) unaudited	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Share Capital				
Balance, beginning of period	$ 3,225,591	$ 3,415,044	$ 3,337,608	$ 3,386,946
Purchase of common shares under Normal Course Issuer Bid	(99,513)	(7,587)	(215,936)	(7,587)
Share-based compensation – treasury settled	—	—	4,406	23,389
Stock Option Plan – cash	—	4,398	—	8,742
Stock Option Plan – exercised	—	336	—	701
Balance, end of period	$ 3,126,078	$ 3,412,191	$ 3,126,078	$ 3,412,191
Paid-in Capital				
Balance, beginning of period	$ 49,472	$ 65,697	$ 46,524	$ 75,375
Share-based compensation – cash settled (tax withholding)	—	—	(4,952)	—
Share-based compensation – treasury settled	—	—	(4,406)	(23,389)
Share-based compensation – non-cash	4,703	4,349	17,009	18,425
Stock Option Plan – exercised	—	(336)	—	(701)
Balance, end of period	$ 54,175	$ 69,710	$ 54,175	$ 69,710
Accumulated Deficit				
Balance, beginning of period	$ (1,655,999)	$ (2,097,302)	$ (1,772,084)	$ (2,124,676)
Purchase of common shares under Normal Course Issuer Bid	34,741	(880)	60,780	(880)
Net income/(loss)	65,181	86,923	169,423	128,964
Dividends declared ($0.01 per share)	(6,836)	(7,355)	(21,032)	(22,022)
Balance, end of period	$ (1,562,913)	$ (2,018,614)	$ (1,562,913)	$ (2,018,614)
Accumulated Other Comprehensive Income/(Loss)				
Balance, beginning of period	$ 318,377	$ 325,482	$ 388,941	$ 263,124
Change in cumulative translation adjustment	19,547	(26,743)	(51,017)	35,615
Balance, end of period	$ 337,924	$ 298,739	$ 337,924	$ 298,739
Total Shareholders' Equity	$ 1,955,264	$ 1,762,026	$ 1,955,264	$ 1,762,026

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

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Note	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Operating Activities					
Net income/(loss)		$ 65,181	$ 86,923	$ 169,423	$ 128,964
Non-cash items add/(deduct):					
Depletion, depreciation and accretion		94,423	81,509	258,649	218,720
Changes in fair value of derivative instruments	16	(14,942)	30,403	52,033	131,238
Deferred income tax expense/(recovery)	14	18,570	15,029	49,499	30,743
Foreign exchange (gain)/loss on debt and working capital	13	8,615	(12,154)	(24,987)	17,881
Share-based compensation and general and administrative	12,15	4,899	4,349	17,568	18,425
Translation of U.S. dollar cash held in Canada	13	(1,469)	4,292	7,885	(6,750)
Asset retirement obligation expenditures	9	(2,926)	(2,757)	(8,819)	(8,141)
Changes in non-cash operating working capital	18	(12,545)	8,504	(15,503)	(13,915)
Cash flow from/(used in) operating activities		159,806	216,098	505,748	517,165
Financing Activities					
Senior notes	8	—	—	(59,429)	(29,044)
Proceeds from the issuance of shares	15	—	4,398	—	8,742
Purchase of common shares under Normal Course Issuer Bid	15	(64,772)	(8,467)	(155,156)	(8,467)
Share-based compensation – cash settled (tax withholding)	15	—	—	(4,952)	—
Dividends	15,18	(6,907)	(7,356)	(21,180)	(21,994)
Cash flow from/(used in) financing activities		(71,679)	(11,425)	(240,717)	(50,763)
Investing Activities					
Capital and office expenditures	18	(232,179)	(209,072)	(512,256)	(465,182)
Property and land acquisitions		(13,344)	(1,702)	(18,236)	(10,284)
Property divestments		(168)	(762)	9,855	(56)
Cash flow from/(used in) investing activities		(245,691)	(211,536)	(520,637)	(475,522)
Effect of exchange rate changes on cash and cash equivalents		2,009	(5,948)	(10,745)	10,183
Change in cash and cash equivalents		(155,555)	(12,811)	(266,351)	1,063
Cash and cash equivalents, beginning of period		252,531	360,422	363,327	346,548
Cash and cash equivalents, end of period		$ 96,976	$ 347,611	$ 96,976	$ 347,611

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

Notes to Condensed Consolidated Financial Statements
(unaudited)

1) REPORTING ENTITY

These interim Condensed Consolidated Financial Statements ("interim 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) BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under accounting principles generally accepted in the United States of America ("U.S. GAAP") for the three and nine months ended September 30, 2019 and the 2018 comparative periods. Certain information and notes normally included with the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with Enerplus' annual audited Consolidated Financial Statements as of December 31, 2018. There are no differences in the use of estimates or judgments between these interim Consolidated Financial Statements and the annual audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2018.

These unaudited interim Consolidated Financial Statements reflect, in the opinion of Management, all normal and recurring adjustments necessary to present fairly the financial position and results of the Company as at and for the periods presented.

3) ACCOUNTING POLICY CHANGES

a) Recently adopted accounting standards

Enerplus adopted ASC 842 *Leases* effective January 1, 2019 as detailed below. Enerplus used the modified retrospective method to adopt the new standard, 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 right-of-use ("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 cash flows.

As a result of this adoption, Enerplus has revised its accounting policy for leases as follows:

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 assets, current lease liabilities, and long-term lease liabilities in the Consolidated Balance Sheets.

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.

b) 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 significantly 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 does not expect to early adopt the standard and does not expect a material impact on 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 value of the reporting unit exceeds its fair value. The updated guidance is effective January 1, 2020. Early adoption is permitted. The amended standard may affect goodwill impairment tests past the adoption date, the impact of which is not known.

4) ACCOUNTS RECEIVABLE

($ thousands)	September 30, 2019	December 31, 2018
Accrued revenue	$ 133,778	$ 118,821
Accounts receivable – trade	44,149	30,252
Allowance for doubtful accounts	(3,827)	(3,867)
Total accounts receivable, net of allowance for doubtful accounts	$ 174,100	$ 145,206

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

As of September 30, 2019 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties[1]	$ 15,106,710	$ (13,559,185)	$ 1,547,525
Other capital assets	126,148	(104,487)	21,661
Total PP&E	$ 15,232,858	$ (13,663,672)	$ 1,569,186

As of 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.

6) ASSET IMPAIRMENT

There was no impairment recorded for the nine months ended September 30, 2019 and 2018.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from September 30, 2018 through September 30, 2019:

Period	WTI Crude Oil US$/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	Exchange Rate US$/CDN$
Q3 2019	$ 57.77	$ 62.79	$ 2.83	1.33
Q2 2019	61.38	66.07	3.02	1.32
Q1 2019	63.00	67.30	3.07	1.32
Q4 2018	65.56	69.58	3.10	1.28
Q3 2018	63.43	74.38	2.92	1.28

7) ACCOUNTS PAYABLE

($ thousands)	September 30, 2019	December 31, 2018
Accrued payables	$ 99,105	$ 115,388
Accounts payable – trade	167,547	174,657
Total accounts payable	$ 266,652	$ 290,045

8) DEBT

($ thousands)	September 30, 2019	December 31, 2018
Current:		
Senior notes	$ 108,047	$ 60,001
Long-term:		
Bank credit facility	—	—
Senior notes	510,308	636,849
Total debt	$ 618,355	$ 696,850

The terms and rates of the Company's outstanding senior notes are provided 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	$ 139,031
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	26,482
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$298,000	394,582
June 18, 2009	June 18 and Dec 18	2 equal annual installments June 18, 2020 - 2021	7.97%	US$225,000	US$44,000	58,260
					Total carrying value	$ 618,355

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

Subsequent to the quarter, Enerplus completed a two year extension of its senior, unsecured bank credit facility to October 31, 2023. As part of the extension, Enerplus amended the credit facility to US$600 million from CAD$800 million. There were no other significant amendments or additions to the agreement terms or covenants.

9) ASSET RETIREMENT OBLIGATION

($ thousands)	Nine months ended September 30, 2019	Year ended December 31, 2018
Balance, beginning of year	$ 126,112	$ 117,736
Change in estimates	9,421	16,755
Property acquisitions and development activity	1,278	1,565
Divestments	(2,242)	(4,585)
Settlements	(8,819)	(11,263)
Accretion expense	4,434	5,904
Balance, end of period	$ 130,184	$ 126,112

Enerplus has estimated the present value of its asset retirement obligation to be $130.2 million at September 30, 2019 based on a total undiscounted liability of $345.9 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 5.53% (December 31, 2018 – 5.59%).

10) 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.

	At September 30, 2019
Weighted average remaining lease term (years)	
Operating leases	4.4

Weighted average discount rate	
Operating leases	4.1%

The components of lease expense for the three and nine months ended September 30, 2019 are as follows:

($ thousands)	Three months ended September 30, 2019	Nine months ended September 30, 2019	Financial Statement Presentation
Operating lease expense[1]	$ 2,771	$ 11,234	PP&E
Operating lease expense[1]	5,284	11,660	Operating expense
Operating lease expense[1]	1,552	4,805	G&A expense
Sublease income	(281)	(781)	G&A expense
Total	$ 9,326	$ 26,918	

(1) Includes short-term and variable lease costs of $4.6 million and $13.0 million for the three and nine months ended September 30, 2019, respectively.

Maturities of lease liabilities, all of which are classified as operating leases at September 30, 2019, are as follows:

Maturity of Lease Liabilities ($ thousands)	Operating Leases
2019	$ 4,744
2020	19,615
2021	14,242
2022	7,696
After 2022	17,008
Total lease payments	$ 63,305
Less imputed interest	(5,563)
Total discounted lease payments	$ 57,742
Current portion of lease liabilities	$ 17,460
Non-current portion of lease liabilities	$ 40,282

Supplemental information related to leases is as follows:

($ thousands)	Three months ended September 30, 2019	Nine months ended September 30, 2019
Cash amounts paid to settle lease liabilities:		
Operating cash flow used for operating leases	$ 4,878	$ 14,142
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$ 618	$ 20,585

11) OIL AND NATURAL GAS SALES

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2019	2018	2019	2018
Oil and natural gas sales	$ 401,769	$ 466,386	$ 1,161,351	$ 1,201,760
Royalties(1)	(82,920)	(92,809)	(233,587)	(235,779)
Oil and natural gas sales, net of royalties	$ 318,849	$ 373,577	$ 927,764	$ 965,981

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

Oil and natural gas revenue by country and by product for the three and nine months ended September 30, 2019 and 2018 are as follows:

Three months ended September 30, 2019 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 38,772	$ 34,309	$ 2,317	$ 1,510	$ 636
United States	280,077	236,609	42,766	702	—
Total	$ 318,849	$ 270,918	$ 45,083	$ 2,212	$ 636

Three months ended September 30, 2018 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 55,885	$ 44,973	$ 6,820	$ 3,463	$ 629
United States	317,692	255,074	57,088	5,530	—
Total	$ 373,577	$ 300,047	$ 63,908	$ 8,993	$ 629

Nine months ended September 30, 2019 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 139,049	$ 115,115	$ 16,388	$ 5,578	$ 1,968
United States	788,715	612,277	167,688	8,750	—
Total	$ 927,764	$ 727,392	$ 184,076	$ 14,328	$ 1,968

Nine months ended September 30, 2018 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 162,787	$ 125,981	$ 23,041	$ 11,296	$ 2,469
United States	803,194	624,337	161,375	17,482	—
Total	$ 965,981	$ 750,318	$ 184,416	$ 28,778	$ 2,469

(1) Royalties above do not include production taxes which are reported separately on the Condensed 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.

12) GENERAL AND ADMINISTRATIVE EXPENSE

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2019	2018	2019	2018
General and administrative expense	$ 11,878	$ 12,000	$ 36,105	$ 37,336
Share-based compensation expense	4,773	4,291	17,936	19,368
General and administrative expense(1)	$ 16,651	$ 16,291	$ 54,041	$ 56,704

(1) Includes cash and non-cash amounts.

13) FOREIGN EXCHANGE

($ thousands)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Realized:				
Foreign exchange (gain)/loss	$ (11)	$ 266	$ (40)	$ 555
Translation of U.S. dollar cash held in Canada (gain)/loss	(1,469)	4,292	7,885	(6,750)
Unrealized:				
Translation of U.S. dollar debt and working capital (gain)/loss	8,615	(12,154)	(24,987)	17,881
Foreign exchange (gain)/loss	$ 7,135	$ (7,596)	$ (17,142)	$ 11,686

14) INCOME TAXES

($ thousands)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Current tax expense/(recovery)				
Canada	$ —	$ (400)	$ (13,941)	$ (400)
United States	26	492	(5,491)	630
Current tax expense/(recovery)	26	92	(19,432)	230
Deferred tax expense/(recovery)				
Canada	$ 2,250	$ (18,785)	$ 7,499	$ (44,755)
United States	16,320	33,814	42,000	75,498
Deferred tax expense/(recovery)	18,570	15,029	49,499	30,743
Income tax expense/(recovery)	$ 18,596	$ 15,121	$ 30,067	$ 30,973

The difference between the expected income taxes based on the statutory income tax rate and the effective income taxes for the current and prior period is impacted by the following: expected annual earnings, recognition or reversal of valuation allowance, foreign rate differentials for foreign operations, statutory and other rate differentials, non-taxable portions of capital gains and losses, and share-based compensation. Our overall net deferred income tax asset was $408.0 million at September 30, 2019 (December 31, 2018 - $465.1 million).

During the nine months ended September 30, 2019, Enerplus recorded a deferred tax expense of $26.3 million for remeasurement of its Canadian net deferred income tax asset for the change in the Alberta corporate tax rate.

During the nine months ended September 30, 2019, the current tax recovery included $5.5 million related to the reversal of the reserve recorded at December 31, 2017 for the sequestered portions of the U.S. Alternative Minimum Tax ("AMT") refund and the favorable settlement of $13.9 million from an outstanding dispute with the Canadian tax authorities.

At September 30, 2019, the current income tax receivable included $28.2 million related to a portion of the U.S. AMT refund (December 31, 2018 - $54.4 million).

15) SHAREHOLDERS' EQUITY

a) Share Capital

	Nine months ended September 30, 2019		Year ended December 31, 2018	
Authorized unlimited number of common shares issued: (thousands)	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	239,411	$ 3,337,608	242,129	$ 3,386,946
Issued/(Purchased) for cash:				
Purchase of common shares under Normal Course Issuer Bid	(15,504)	(215,936)	(5,925)	(82,596)
Stock Option Plan	—	—	668	9,138
Non-cash:				
Share-based compensation – settled[(1)]	564	4,406	2,539	23,389
Stock Option Plan – exercised	—	—	—	731
Balance, end of period	224,471	$ 3,126,078	239,411	$ 3,337,608

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

Dividends declared to shareholders for the three and nine months ended September 30, 2019 were $6.8 million and $21.0 million, respectively (2018 – $7.4 million and $22.0 million, respectively).

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 ("TSX"), New York Stock Exchange and/or alternative Canadian trading systems. Pursuant to the NCIB renewal, 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 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 public float (or an additional 7,145,578 common shares) until the expiry of the NCIB on March 25, 2020, subject to TSX approval.

During the three months ended September 30, 2019, the Company repurchased 7,145,070 common shares under the current NCIB at an average price of $9.06 per share, for total consideration of $64.8 million. Of the amount paid, $99.5 million was charged to share capital and $34.7 million was credited to accumulated deficit.

During the nine months ended September 30, 2019, the Company repurchased 15,503,891 common shares under the previous and current NCIB at an average price of $10.00 per share, for total consideration of $155.1 million. Of the amount paid, $215.9 million was charged to share capital and $60.8 million was credited to accumulated deficit.

During the three and nine months ended September 30, 2018, the Company repurchased 544,300 common shares under the previous NCIB at an average price of $15.54 per share, for total consideration of $8.5 million. Of the amount paid, $7.6 million was charged to share capital and $0.9 million was charged to accumulated deficit.

Subsequent to the quarter, and up to November 6, 2019, the Company repurchased an additional 2,727,510 common shares under the NCIB at an average price of $8.66 per share, for total consideration of $23.6 million.

b) Share-based Compensation

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

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2019	2018	2019	2018
Cash:				
Long-term incentive plans (recovery)/expense	$ 56	$ (211)	$ 767	$ 2,170
Non-cash:				
Long-term incentive plans	4,703	4,349	17,009	18,425
Equity swap (gain)/loss	14	153	160	(1,227)
Share-based compensation expense	$ 4,773	$ 4,291	$ 17,936	$ 19,368

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

The following table summarizes the Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Deferred Share Unit ("DSU") plan activity for the nine months ended September 30, 2019:

For the nine months ended September 30, 2019	Cash-settled LTI plans	Equity-settled LTI plans		Total
(thousands of units)	DSU(1)	PSU(2)	RSU	
Balance, beginning of year	391	1,371	1,753	3,515
Granted	98	810	856	1,764
Vested	(68)	—	(1,007)	(1,075)
Forfeited	—	(49)	(58)	(107)
Balance, end of period	421	2,132	1,544	4,097

(1) Settlement of units vested has been deferred.
(2) Based on underlying awards before any effect of the performance multiplier.

Cash-settled LTI Plans

For the three and nine months ended September 30, 2019, the Company recorded cash share-based compensation expense of $0.1 million and $0.8 million, respectively (September 30, 2018 – recovery of $0.2 million and expense of $2.2 million, respectively). For the three and nine months ended September 30, 2019, the Company made cash payments of nil and $0.1 million, respectively related to its cash-settled plans (September 30, 2018 – nil and $0.5 million, respectively).

As of September 30, 2019, a liability of $4.8 million (December 31, 2018 – $4.1 million) with respect to the DSU plan has been recorded to Accounts Payable on the Condensed 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 Condensed Consolidated Balance Sheets. Unrecognized amounts will be recorded to non-cash share-based compensation expense over the remaining vesting terms.

At September 30, 2019 ($ thousands, except for years)		PSU[(1)]		RSU		Total
Cumulative recognized share-based compensation expense	$	27,355	$	11,593	$	38,948
Unrecognized share-based compensation expense		12,910		7,703		20,613
Fair value	$	40,265	$	19,296	$	59,561
Weighted-average remaining contractual term (years)		1.7		1.5		

(1) Includes estimated performance multipliers.

The 2016 PSU's which vested and were recognized in December 2018 were cash settled in January 2019.

The Company directly withholds shares on PSU and RSU settlements for tax-withholding purposes. For the nine months ended September 30, 2019, $5.0 million (2018 – nil) in cash withholding taxes were paid.

ii) Stock Option Plan

At September 30, 2019 all stock options are fully vested and any related non-cash share-based compensation expense has been fully recognized.

The following table summarizes the stock option plan activity for the nine months ended September 30, 2019:

Period ended September 30, 2019	Number of Options (thousands)		Weighted Average Exercise Price
Options outstanding, beginning of year	4,131	$	17.12
Forfeited	(86)		15.35
Expired	(1,929)		20.35
Options outstanding, end of period	2,116	$	14.24
Options exercisable, end of period	2,116	$	14.24

At September 30, 2019, Enerplus had 2,116,137 options that were exercisable at a weighted average exercise price of $14.24 with a weighted average remaining contractual term of 0.5 years, giving an aggregate intrinsic value of nil (September 30, 2018 – 1.0 years and $5.4 million). The intrinsic value of options exercised for the three and nine months ended September 30, 2019 was nil and nil, respectively (September 30, 2018 – $1.2 million and $1.8 million, respectively).

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

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

	Three months ended September 30,				Nine months ended September 30,			
(thousands, except per share amounts)		2019		2018		2019		2018
Net income/(loss)	$	65,181	$	86,923	$	169,423	$	128,964
Weighted average shares outstanding – Basic		228,908		245,235		234,403		244,659
Dilutive impact of share-based compensation		2,621		5,722		2,996		5,389
Weighted average shares outstanding – Diluted		231,529		250,957		237,399		250,048
Net income/(loss) per share								
Basic	$	0.28	$	0.35	$	0.72	$	0.53
Diluted	$	0.28	$	0.35	$	0.71	$	0.52

16) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At September 30, 2019, the carrying value of cash, accounts receivable, accounts payable, and dividends payable approximated their fair value due to the short-term maturity of the instruments.

At September 30, 2019, the senior notes had a carrying value of $618.4 million and a fair value of $634.8 million (December 31, 2018 – $696.9 million and $695.4 million, respectively).

The fair value of derivative contracts and senior notes are considered level 2 fair value measurements. There were no transfers between fair value hierarchy levels during the period.

b) Derivative Financial Instruments

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

The following table summarizes the change in fair value for the three and nine months ended September 30, 2019 and 2018:

	Three months ended September 30,		Nine months ended September 30,		Income Statement
Gain/(Loss) ($ thousands)	2019	2018	2019	2018	Presentation
Electricity Swaps	$ —	$ (62)	$ —	$ —	Operating expense
Equity Swaps	(14)	(153)	(160)	1,227	G&A expense
Commodity Derivative Instruments:					
Oil	20,505	(29,977)	(42,807)	(130,737)	Commodity derivative
Gas	(5,549)	(211)	(9,066)	(1,728)	instruments
Total	$ 14,942	$ (30,403)	$ (52,033)	$ (131,238)	

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

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2019	2018	2019	2018
Change in fair value gain/(loss)	$ 14,956	$ (30,188)	$ (51,873)	$ (132,465)
Net realized cash gain/(loss)	5,231	(23,866)	14,615	(33,004)
Commodity derivative instruments gain/(loss)	$ 20,187	$ (54,054)	$ (37,258)	$ (165,469)

The following table summarizes the fair values of derivative financial instruments at the respective period ends:

	September 30, 2019				December 31, 2018		
	Assets		Liabilities		Assets		Liabilities
($ thousands)	Current	Long-term	Current	Long-term	Current	Long Term	Current
Equity Swaps	$ —	$ —	$ 2,069	$ —	$ —	$ —	$ 1,909
Commodity Derivative Instruments:							
Oil	43,975	875	—	7,123	48,314	32,220	—
Gas	1,878	—	—	—	10,944	—	—
Total	$ 45,853	$ 875	$ 2,069	$ 7,123	$ 59,258	$ 32,220	$ 1,909

c) Risk Management

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 derivatives 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 the Company's price risk management positions at November 6, 2019:

Crude Oil Instruments:

Instrument Type[(1)(2)]	bbls/day	US$/bbl
Oct 1, 2019 – Dec 31, 2019		
WTI Purchased Put	24,500	54.81
WTI Sold Call	24,500	65.99
WTI Sold Put	24,500	44.64
WCS Differential Swap	1,500	(14.83)
WTI – Brent Swap	2,700	(8.10)
Jan 1, 2020 – Dec 31, 2020		
WTI Purchased Put	16,000	57.50
WTI Sold Put	16,000	46.88
WTI – Brent Swap	4,400	(8.03)

(1) Transactions with a common term have been aggregated and presented at a weighted average price/bbl before premiums.
(2) The total average deferred premium on outstanding hedges is US$2.14/bbl from October 1, 2019 to December 31, 2020.

For the remainder of 2019, Enerplus has physical sales contracts in place for approximately 24,800 bbls/day of North Dakota production with fixed differentials averaging approximately US$2.69/bbl below WTI, a portion of which is sold directly into the U.S. Gulf Coast that utilizes the Company's firm capacity on the Dakota Access Pipeline.

Natural Gas Instruments:

Instrument Type[(1)]	MMcf/day	US$/Mcf
Oct 1, 2019 – Oct 31, 2019		
NYMEX Swap (Sale)	90.0	2.85
NYMEX Swap (Purchase)	90.0	2.34

(1) Transactions with a common term have been aggregated and presented at a weighted average price/Mcf.

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 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 September 30, 2019, Enerplus did not have any foreign exchange derivatives outstanding.

Interest Rate Risk:

At September 30, 2019, all of Enerplus' debt was based on fixed interest rates and Enerplus had no 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 15. Enerplus has entered into various equity swaps maturing between 2019 and 2020 that effectively fix 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 September 30, 2019, 85% 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 of 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 uncollectable, the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at September 30, 2019 was $3.8 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 share capital. Enerplus' objective is to provide adequate short and long 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, and acquisition and divestment activity.

At September 30, 2019, Enerplus was in full compliance with all covenants under the bank credit facility and outstanding senior notes.

17) COMMITMENTS AND CONTINGENCIES

As of the date of this report, other than changes related to the adoption of the new lease accounting standard as described in Note 3, there were no material changes to Enerplus' contractual obligations and commitments outside the ordinary course of business as reported in the Company's annual audited Consolidated Financial Statements as of December 31, 2018.

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.

18) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2019	2018	2019	2018
Accounts receivable	$ (638)	$ (21,064)	$ 22,763	$ (72,564)
Other assets	(6,034)	(1,537)	(4,170)	1,622
Accounts payable	(5,873)	31,105	(34,096)	57,027
	$ (12,545)	$ 8,504	$ (15,503)	$ (13,915)

b) Changes in Other Non-Cash Working Capital

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2019	2018	2019	2018
Non-cash financing activities(1)	$ (71)	$ (1)	$ (148)	$ 28
Non-cash investing activities(2)	(77,780)	(14,160)	13,360	61,964

(1) Relates to changes in dividends payable and included in dividends on the Condensed 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 Condensed Consolidated Statements of Cash Flows.

c) Other

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2019	2018	2019	2018
Income taxes paid/(received)	$ (11,985)	$ (398)	$ (69,584)	$ (481)
Interest paid	4,016	3,352	21,665	21,545

BOARD OF DIRECTORS

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Corporate Director
Boerne, 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

Jodine J. Jenson Labrie
Senior Vice President & Chief Financial Officer

Garth R. Doll
Vice President, Marketing

Terry S. Eichinger
Vice President, U.S. Operations and 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

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TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta
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U.S. CO-TRANSFER AGENT

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McDaniel & Associates Consultants Ltd.
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Netherland, Sewell & Associates, Inc.
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STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS

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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	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
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 at Edmonton, Alberta, the benchmark for Canadian light sweet crude oil pricing
NCIB	Normal Course Issuer Bid
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange, the benchmark for North American natural gas pricing
SBC	share based compensation
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
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
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

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