First Quarter Report

Three Months Ended March 31, 2019

SELECTED FINANCIAL RESULTS	Three months ended March 31, 2019	2018
Financial (000's)		
Net Income	$ 19,158	$ 29,637
Cash Flow from Operating Activities	108,951	159,300
Adjusted Funds Flow[4]	168,755	155,162
Dividends to Shareholders - Declared	7,162	26
Total Debt Net of Cash[4]	363,771	291,978
Capital Spending	160,793	151,472
Property and Land Acquisitions	3,025	12,272
Property Divestments	466	6,970
Net Debt to Adjusted Funds Flow Ratio[4]	0.5x	0.5x
Financial per Weighted Average Shares Outstanding		
Net Income - Basic	$ 0.08	$ 0.12
Net Income - Diluted	0.08	0.12
Weighted Average Number of Shares Outstanding (000's) - Basic	238,922	243,874
Weighted Average Number of Shares Outstanding (000's) - Diluted	241,298	249,191
Selected Financial Results per BOE[1][2]		
Oil & Natural Gas Sales[3]	$ 44.70	$ 42.91
Royalties and Production Taxes	(10.48)	(10.41)
Commodity Derivative Instruments	1.32	1.33
Cash Operating Expenses	(8.75)	(7.02)
Transportation Costs	(3.92)	(3.52)
Cash General and Administrative Expenses	(1.55)	(1.72)
Cash Share-Based Compensation	(0.17)	(0.25)
Interest, Foreign Exchange and Other Expenses	(0.68)	(1.05)
Current Income Tax Recovery/(Expense)	0.69	(0.01)
Adjusted Funds Flow[4]	$ 21.16	$ 20.26

SELECTED OPERATING RESULTS	Three months ended March 31, 2019	2018
Average Daily Production[2]		
Crude Oil (bbls/day)	41,105	37,443
Natural Gas Liquids (bbls/day)	4,383	4,085
Natural Gas (Mcf/day)	258,568	261,310
Total (BOE/day)	88,583	85,080
% Crude Oil and Natural Gas Liquids	51%	49%
Average Selling Price [2][3]		
Crude Oil (per bbl)	$ 66.56	$ 69.67
Natural Gas Liquids (per bbl)	19.15	28.13
Natural Gas (per Mcf)	4.38	3.50
Net Wells Drilled	17	14

(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 March 31, 2019	2018
WTI crude oil (US$/bbl)	$ 54.90	$ 62.87
Brent (ICE) crude oil (US$/bbl)	63.90	67.18
NYMEX natural gas – last day (US$/Mcf)	3.10	3.00
USD/CDN average exchange rate	1.33	1.26

Share Trading Summary For the three months ended March 31, 2019	CDN[(1)] - ERF (CDN$)	U.S.[(2)] - ERF (US$)
High	$ 12.55	$ 9.47
Low	$ 10.12	$ 7.44
Close	$ 11.20	$ 8.41

(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

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

NEWS RELEASE

Highlights:

- Strong pricing in the Bakken and Marcellus helped drive first quarter adjusted funds flow of $168.8 million
- 2019 production guidance increased to 97,000 to 101,000 BOE per day with 53,500 to 56,000 barrels per day of liquids production
    - Mid-point implies 10% year-over-year liquids production growth (13% per share)
- Oil growth underway with second quarter liquids production expected to be approximately 15% higher than the first quarter
- Visibility to meaningful free cash flow in the second half of 2019 based on current forward commodity prices
- Repurchased approximately $35 million of the Company's stock year-to-date with plans to accelerate share repurchases, based on current market conditions
- 2019 capital spending guidance range narrowed to $590 to $630 million (from $565 to $635 million) following the continued optimization of operational plans
- Significant financial flexibility; total debt net of cash was $363.8 million leading to a net debt to adjusted funds flow ratio of 0.5 times

"Our 2019 plans remain on track," stated Ian C. Dundas, President and Chief Executive Officer. "As anticipated, we saw production decline in the first quarter as a result of our 2018 investment profile which was front-half weighted. However, the growth we had projected as we moved past the first quarter is now well underway. With solid operational momentum established, we anticipate robust growth going forward."

Dundas continued, "With our operational plan delivering sustainable, double-digit oil production growth, we will continue to maintain capital spending discipline and prioritize free cash flow generation and return of capital to shareholders. With this in mind, and given our strong liquidity position and the compelling value we currently see in our shares, we plan to accelerate share repurchases under our normal course issuer bid. Additionally, we plan to allocate a meaningful percentage of our expected free cash flow in the second half of the year towards share repurchases, based on current market conditions."

First Quarter Financial and Operational Summary

PRODUCTION

Production in the first quarter averaged 88,583 BOE per day, including oil and natural gas liquids production of 45,488 barrels per day (90% oil). First quarter production declined 9% from the prior quarter as a result of the Company's 2018 investment profile which included only modest capital activity in the fourth quarter.

With strong well performance in North Dakota and the Marcellus driving growth and momentum into the second quarter, Enerplus remains well positioned relative to its 2019 production targets. The Company is increasing its annual production guidance to 97,000 to 101,000 BOE per day (from 94,000 to 100,000 BOE per day) including liquids production of 53,500 to 56,000 barrels per day (from 52,500 to 56,000 barrels per day).

Second quarter production is expected to average 97,500 to 100,000 BOE per day, with liquids production of 51,500 to 53,000 barrels per day.

ADJUSTED FUNDS FLOW AND ADJUSTED NET INCOME

First quarter adjusted funds flow was $168.8 million compared to $214.3 million in the fourth quarter of 2018. First quarter adjusted net income was $72.5 million ($0.30 per share) compared to $102.2 million ($0.42 per share) in the fourth quarter of 2018. The quarter-over-quarter decreases in adjusted funds flow and adjusted net income were primarily due to lower oil production in the first quarter. Adjusted funds flow in the fourth quarter also benefitted from a $27.2 million Alternative Minimum Tax refund.

PRICING REALIZATION AND COST STRUCTURE

Enerplus' realized Bakken oil price differential averaged US$3.25 per barrel below WTI in the first quarter, an improvement from US$5.60 per barrel below WTI in the prior quarter due to the return of normal refining activity levels in the U.S. Midwest. For the remainder of 2019, Enerplus has fixed physical differential sales of approximately 19,000 barrels per day of Bakken oil production at US$1.90 per barrel below WTI, including a portion which is sold directly into the U.S. Gulf Coast that utilizes the Company's firm capacity on the Dakota Access Pipeline. Enerplus' remaining production is sold on a monthly basis into the highest netback markets available. The Company is maintaining its annual average Bakken differential guidance of US$4.00 per barrel below WTI.

The Company's first quarter realized Marcellus natural gas price differential was US$0.13 per Mcf above NYMEX, compared to US$0.34 below NYMEX during the prior quarter. The premium differential to NYMEX in the quarter was driven by strong weather-related demand and the Company's fixed physical basis sales at markedly higher levels than the settled benchmarks. Increased takeaway capacity from additional pipelines brought into service also supported the strong first quarter Marcellus pricing. Differentials have weakened following the first quarter due to the seasonality of pricing and demand in the northeastern U.S. markets. Enerplus expects its realized differentials for the remainder of the year to moderate from the first quarter and is maintaining its full year average Marcellus differential guidance of US$0.30 per Mcf below NYMEX**.**

First quarter operating expenses were $8.75 per BOE, an increase from $6.99 per BOE in the fourth quarter largely due to lower first quarter production. With production growth underway following the first quarter decline, operating costs per BOE are expected to be lower during the remainder of 2019. The Company is maintaining its full year operating cost guidance of $8.00 per BOE.

First quarter transportation and cash general and administrative ("G&A") expenses were both largely in line with the Company's annual 2019 guidance. First quarter transportation costs were $3.92 per BOE and cash G&A expenses were $1.55 per BOE. Enerplus' 2019 guidance for these items remains unchanged.

CAPITAL EXPENDITURES AND BALANCE SHEET POSITION

Exploration and development capital spending in the first quarter was $160.8 million and was associated with drilling 17.1 net wells and bringing 6.8 net wells on production across the Company's operations. Capital spending is expected to increase in the second quarter primarily due to a higher number of well completions in North Dakota compared to the first quarter.

Enerplus has narrowed its 2019 capital budget range to $590 to $630 million (from $565 to $635 million previously) following the continued optimization of its operational plans in North Dakota. The Company expects to complete and bring approximately 35 net operated wells on production in 2019 at Fort Berthold.

Total debt net of cash at March 31, 2019 was $363.8 million. Total debt was comprised of $682.8 million of senior notes outstanding. The Company was undrawn on its $800 million bank credit facility and had a cash balance of $319.0 million. Enerplus' net debt to adjusted funds flow ratio was 0.5 times at the quarter-end.

SHARE REPURCHASE

During the first quarter, the Company repurchased 1.7 million shares at an average share price of $11.43 for a cost of $19.8 million under its normal course issuer bid ("NCIB"). In total, including repurchases made subsequent to the end of the first quarter and up to May 8, 2019, the Company has repurchased 3.0 million shares in 2019 at an average share price of $11.61 for total consideration of $34.8 million.

Enerplus renewed its NCIB commencing on March 26, 2019 for a period of twelve months. The NCIB renewal allows the Company to repurchase up to 16.7 million shares, representing approximately $190 million based on its most recent closing share price.

ASSET ACTIVITY

Average Daily Production(1)

	Three months ended March 31, 2019			
	Crude Oil (Mbbl/d)	**NGL** (Mbbl/d)	**Natural Gas** (MMcf/d)	**Total** (Mboe/d)
Williston Basin	31.3	3.4	25.2	38.9
Marcellus	—	—	209.0	34.8
Canadian Waterfloods	8.8	0.1	3.1	9.4
Other(2)	1.0	0.9	21.3	5.5
Total	**41.1**	**4.4**	**258.6**	**88.6**

(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 March 31, 2019			
	Operated		Non Operated	
	Gross	Net	Gross	Net
Williston Basin	3.0	3.0	1.0	0.5
Marcellus	—	—	13.0	1.9
Canadian Waterfloods	1.0	1.0	—	—
Other[2]	—	—	2.0	0.5
Total	**4.0**	**4.0**	**16.0**	**2.8**

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

WILLISTON BASIN

Williston Basin production averaged 38,916 BOE per day (80% oil) during the first quarter of 2019, down from 47,420 BOE in the prior quarter. The sequential quarterly decline was due to modest capital activity in the fourth quarter of 2018 during which Enerplus brought one well on production. First quarter Williston Basin production was comprised of 35,889 BOE per day in North Dakota and 3,027 BOE per day in Montana.

In the first quarter, Enerplus brought a three-well (100% working interest) pad on production at Fort Berthold. The average peak 30-day production rate per well was 1,900 BOE per day (74% oil, on a three-stream basis) with an average completed lateral length of 9,600 feet per well.

The Company drilled 15 gross operated wells (95% average working interest) in the first quarter.

MARCELLUS

Marcellus production averaged 209 MMcf per day during the first quarter, approximately flat from the previous quarter.

Thirteen gross non-operated wells (14% average working interest) were brought on-stream during the quarter. The average peak 30-day production rate per well was 22 MMcf per day with an average completed lateral length per well of 7,700 feet.

The Company participated in drilling nine gross non-operated wells (2% average working interest) during the first quarter.

2019 Guidance Updates

The Company has revised its 2019 production and capital spending guidance ranges, with changes noted in the table below. In addition, production guidance for the second quarter of 2019 has been provided.

	Guidance
Capital spending	$590 to $630 million (from $565 to $635 million)
Average annual production	97,000 to 101,000 BOE/day (from 94,000 to 100,000 BOE/day)
Average annual crude oil and natural gas liquids production	53,500 to 56,000 bbls/day (from 52,500 to 56,000 bbls/d)
Second quarter average production	97,500 to 100,000 BOE/d
Second quarter average crude oil and natural gas liquids production	51,500 to 53,000 bbls/day
Average royalty and production tax rate	25%
Operating expense	$8.00/BOE
Transportation expense	$4.00/BOE
Cash G&A expense	$1.50/BOE

2019 Full-Year Differential/Basis Outlook[1]	
U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(4.00)/bbl
Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.30)/Mcf

(1) Excluding transportation costs.

Risk Management

Enerplus continues to manage price risk through commodity hedging. Enerplus has an average of 24,170 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 90,000 Mcf per day of natural gas production protected from April 1 to October 31, 2019.

Commodity Hedging Detail (As at May 8, 2019)

	WTI Crude Oil (US$/bbl)[1]				NYMEX Natural Gas (US$/Mcf)
	Apr 1, 2019 – Jun 30, 2019	**Jul 1, 2019 – Sep 30, 2020**	**Oct 1, 2019 – Dec 31, 2019**	**Jan 1, 2020 – Dec 31, 2020**	**Apr 1, 2019 – Oct 31, 2019**
Swaps					
Sold Swaps	—	—	—	—	$ 2.85
Volume (bbls/d or Mcf/d)	—	—	—	—	90,000
Three Way Collars					
Sold Puts	$ 44.50	$ 44.64	$ 44.64	$ 46.88	—
Volume (bbls/d or Mcf/d)	23,500	24,500	24,500	16,000	—
Purchased Puts	$ 54.59	$ 54.81	$ 54.81	$ 57.50	—
Volume (bbls/d or Mcf/d)	23,500	24,500	24,500	16,000	—
Sold Calls	$ 65.52	$ 65.95	$ 65.99	$ 72.50	—
Volume (bbls/d or Mcf/d)	23,500	24,500	24,500	16,000	—

(1) The total average deferred premium spent on the three-way collars is US$1.59/bbl from April 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.

Readers are cautioned that the average initial production rates contained in this news release are not necessarily indicative of long-term performance or of ultimate recovery.

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 2019, including second quarter, 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$60.00/bbl, a NYMEX price of US$2.75/Mcf, and a USD/CDN exchange rate of 1.33. 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", "free cash flow", "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 net cash generated from operating activities but before changes in non-cash operating working capital and asset retirement obligation expenditures. "Net debt to adjusted funds flow ratio" is calculated as total debt net of cash and restricted cash, 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 restricted cash. Free cash flow is defined as "Adjusted funds flow less exploration and development capital spending". Calculation of these terms is described in Enerplus' MD&A under the "Liquidity and Capital Resources" section.

Enerplus believes that, in addition to net earnings and other measures prescribed by U.S. GAAP, the terms "adjusted funds flow", "free cash flow", "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' First Quarter 2019 MD&A.

Electronic copies of Enerplus Corporation's First 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 May 9, 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 months ended March 31, 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 in 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 first quarter averaged 88,583 BOE/day, a 9% decrease compared to the fourth quarter of 2018. Production decreased in North Dakota as expected, due to modest capital spending in the fourth quarter of 2018, along with the planned timing of wells coming on-stream towards the end of the quarter. Despite the lower production in the first quarter, we expect strong well performance for the remainder of the year and we are increasing our average annual production guidance to 97,000 – 101,000 BOE/day from 94,000 – 100,000 BOE/day and revising our average annual crude oil and natural gas liquids guidance to 53,500 – 56,000 bbls/day from 52,500 – 56,000 bbls/day. In addition, we expect second quarter average production of 97,500 – 100,000 BOE/day, with crude oil and natural gas liquids production of 51,500 – 53,000 bbls/day.

Capital expenditures of $160.8 million were in line with our expectations, with approximately 70% of our capital spending directed to our North Dakota crude oil properties. We are narrowing our 2019 annual capital spending guidance range to $590 – $630 million from $565 – $635 million, following the continued optimization of our operational plans in North Dakota.

Operating costs for the quarter increased to $69.8 million or $8.75/BOE from $62.9 million or $6.99/BOE in the fourth quarter of 2018 mainly due to higher well service activity in both Canada and the U.S. and lower production in the first quarter of 2019. We are maintaining our annual operating cost guidance of $8.00/BOE for 2019.

Cash G&A expenses for the quarter were $12.3 million or $1.55/BOE, compared to $12.6 million or $1.40/BOE in the fourth quarter of 2018. Cash G&A expenses remained consistent with the fourth quarter but increased on a per BOE basis, primarily due to lower production volumes during the period. We are maintaining our annual guidance of $1.50/BOE for cash G&A expenses for the year.

During the first quarter of 2019, our Bakken crude oil price differential improved to US$3.25/bbl below WTI, compared to US$5.60/bbl below WTI in the fourth quarter of 2018, as a result of stronger demand from midwest U.S. refineries and severe winter weather in North Dakota reducing Bakken supply in the field. Our Marcellus natural gas differential improved to US$0.13/Mcf above NYMEX in the first quarter, compared to US$0.34/Mcf below NYMEX in the fourth quarter of 2018, due to strong weather-related demand resulting in lower than expected storage inventory in the U.S., and the benefit of a portion of our fixed physical gas sales contracts which are tied to regional New York markets.

As of May 8, 2019, we had approximately 65% of our forecasted crude oil production, net of royalties, hedged for 2019, and approximately 43% of our crude oil production, net of royalties, hedged in 2020, based on 2019 forecasted net production. We have also hedged approximately 45% of our forecasted natural gas production, net of royalties, for the period April 1 to October 31, 2019.

We reported net income of $19.2 million in the first quarter of 2019 compared to $249.3 million in the fourth quarter of 2018. The decrease is primarily the result of a $95.4 million unrealized loss on commodity derivative instruments, compared to a $256.5 million unrealized gain in the fourth quarter of 2018 due to the improvement in crude oil and natural gas prices in the first quarter.

In the first quarter of 2019, cash flow from operations decreased to $109.0 million, compared to $221.6 million in the fourth quarter of 2018 due to lower crude oil production and changes to working capital. Adjusted funds flow in the quarter decreased to $168.8 million from $214.3 million in the fourth quarter of 2018, as a result of lower crude oil production and a reduced Alternative Minimum Tax ("AMT") refund of $5.5 million in the first quarter of 2019, compared to $27.2 million in the prior period.

During the quarter, we repurchased and cancelled 1,732,038 common shares under our Normal Course Issuer Bid ("NCIB") for total consideration of $19.8 million.

At March 31, 2019, our total debt net of cash was $363.8 million and our net debt to adjusted funds flow ratio was 0.5x.

RESULTS OF OPERATIONS

Production

Average daily production for the first quarter totaled 88,583 BOE/day, compared to production of 97,860 BOE/day in the fourth quarter of 2018. Crude oil and liquids production decreased by 8,963 bbls/day, primarily due to lower North Dakota volumes as a result of lower capital spending in the fourth quarter of 2018, along with the expected timing of wells coming on-stream in March 2019. Our natural gas production remained flat, compared to the fourth quarter of 2018.

Production in the first quarter increased by 3,503 BOE/day or 4%, when compared to production of 85,080 BOE/day for the same period of the prior year. A larger capital program in North Dakota resulted in an increase of approximately 4,500 BOE/day of liquids production. This increase was partially offset by the divestment of non-core Canadian properties in the first quarter of 2018.

Our crude oil and natural gas liquids weighting increased to 51% in the first quarter of 2019, from 49% for the same period of 2018, due to increased capital spending on our U.S. crude oil assets.

Average daily production volumes for the three months ended March 31, 2019 and 2018 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2019**	**2018**	**% Change**
Crude oil (bbls/day)	41,105	37,443	10%
Natural gas liquids (bbls/day)	4,383	4,085	7%
Natural gas (Mcf/day)	258,568	261,310	(1%)
Total daily sales (BOE/day)	88,583	85,080	4%

We are increasing our average annual production guidance to 97,000 – 101,000 BOE/day from 94,000 – 100,000 BOE/day and revising our average annual crude oil and natural gas liquids guidance to 53,500 – 56,000 bbls/day from 52,500 – 56,000 bbls/day. In addition, we expect second quarter average production of 97,500 – 100,000 BOE/day, with crude oil and natural gas liquids average production of 51,500 – 53,000 bbls/day.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, adjusted funds flow and financial condition. The following table compares quarterly average prices for the three months ended March 31, 2019 and 2018 and other periods indicated:

Pricing (average for the period)	**Q1 2019**	**Q4 2018**	**Q3 2018**	**Q2 2018**	**Q1 2018**
Benchmarks					
WTI crude oil (US$/bbl)	$ 54.90	$ 58.81	$ 69.50	$ 67.88	$ 62.87
Brent (ICE) crude oil (US$/bbl)	63.90	68.08	75.97	74.90	67.18
NYMEX natural gas – last day (US$/Mcf)	3.10	3.64	2.90	2.80	3.00
USD/CDN average exchange rate	1.33	1.32	1.31	1.29	1.26
USD/CDN period end exchange rate	1.33	1.36	1.29	1.31	1.29
Enerplus selling price[(1)]					
Crude oil ($/bbl)	$ 66.56	$ 64.18	$ 83.98	$ 79.98	$ 69.67
Natural gas liquids ($/bbl)	19.15	26.72	25.95	32.23	28.13
Natural gas ($/Mcf)	4.38	4.28	3.22	2.68	3.50
Average differentials					
Brent (ICE) – WTI (US$/bbl)	$ 9.00	$ 9.27	$ 6.47	$ 7.02	$ 4.31
MSW Edmonton – WTI (US$/bbl)	(4.85)	(26.30)	(6.83)	(5.45)	(5.89)
WCS Hardisty – WTI (US$/bbl)	(12.29)	(39.43)	(22.25)	(19.27)	(24.28)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.22)	(0.39)	(0.61)	(0.91)	(0.67)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(0.27)	(0.49)	(0.68)	(0.99)	(0.76)
Enerplus realized differentials[(1)(2)]					
Bakken crude oil – WTI (US$/bbl)	$ (3.25)	$ (5.60)	$ (2.54)	$ (3.42)	$ (3.27)
Marcellus natural gas – NYMEX (US$/Mcf)	0.13	(0.34)	(0.48)	(0.69)	(0.21)
Canada crude oil – WTI (US$/bbl)	(10.42)	(33.27)	(16.61)	(16.31)	(20.82)

(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 average realized crude oil price for the first quarter of 2019 averaged $66.56/bbl, an increase of 4% compared to the previous quarter, despite a 7% decrease in WTI Benchmark pricing. This increase was due to the strengthening of crude oil differentials in the first quarter of 2019 as U.S. refinery demand returned after record levels of maintenance in the fourth quarter of 2018 combined with mandatory Alberta oil curtailments. As a result, our realized Bakken price differential improved by 42% during the quarter to average US$3.25/bbl below WTI. Our sales price continued to benefit from a portion of our physical sales that were sold on a fixed differential basis below WTI. For the remainder of 2019, we have physical sales contracts in place for an average of 19,000 bbls/day of Bakken crude oil production with fixed differentials averaging approximately US$1.90/bbl below WTI, a portion of which is sold directly into the U.S. Gulf Coast that utilizes our firm capacity on the Dakota Access Pipeline. We are maintaining our full year Bakken differential guidance of US$4.00/bbl below WTI.

Our realized price differential for our Canadian crude oil production improved by US$22.85/bbl compared to the previous quarter. Canadian crude oil prices weakened significantly during the fourth quarter as seasonal U.S. refinery maintenance and growing Canadian crude oil production placed constraints on Canadian pipeline capacity. This pressure has since been relieved mainly due to Alberta Government mandated production curtailments. We have fixed differential hedges in place for 1,500 bbl/day of our 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 $19.15/bbl during the period, which represents a 28% decrease compared to the previous quarter. The reduction is mainly due to price weakness in U.S. benchmark pricing, applicable to both propane and butane production from our U.S. Bakken assets.

NATURAL GAS

Our average realized natural gas price during the first quarter of 2019 increased by 2% compared to the fourth quarter of 2018, to average $4.38/Mcf, while NYMEX benchmark pricing decreased by 15%. The increase was mainly due to continued improvement in Marcellus pricing, where our realized differentials averaged US$0.13/Mcf above NYMEX for the period, compared to US$0.34/Mcf below NYMEX in the fourth quarter. Strong weather-related demand resulted in lower than expected storage inventory in the U.S., especially in the Northeastern region, which resulted in improved differentials. Our realized Marcellus gas price was supported by fixed physical basis sales during the quarter at markedly higher levels than the settled benchmarks. Further, basis differentials in the Marcellus continued to be supported by pipeline additions that were recently brought into service. We expect our realized Marcellus differentials for the remainder of the year to moderate from the first quarter due to the seasonality of pricing and demand in Northeastern U.S. markets and we are maintaining our full year differential guidance for the Marcellus of US$0.30/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 three months in 2019 with an average exchange rate of 1.33 US/CDN compared to 1.26 US/CDN for the same period in 2018. However, when comparing the exchange rate in the first quarter of 2019 to the fourth quarter of 2018, the Canadian dollar strengthened relative to the U.S. dollar.

Price Risk Management

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

As of May 8, 2019, we have hedged approximately 24,170 bbls/day of crude oil, which represents approximately 65% 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% based off our 2019 forecasted crude oil production, after royalties. Our crude oil hedges are all three-way collars, which consist of a sold put, a purchased put and a sold call. When WTI prices settle below the sold put strike price, the three-way collars 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.

As of May 8, 2019, we have hedged approximately 90,000 Mcf/day of our forecasted natural gas production for the period April 1 to October 31, 2019. This represents approximately 45% of our forecasted natural gas production, after royalties, for that period.

The following is a summary of our financial contracts in place at May 8, 2019, expressed as a percentage of our anticipated net production volumes:

	WTI Crude Oil (US$/bbl)(1)(2)			
	Apr 1, 2019 – Jun 30, 2019	Jul 1, 2019 – Sep 30, 2019	Oct 1, 2019 – Dec 31, 2019	Jan 1, 2020 – Dec 31, 2020
Three Way Collars(2)				
Sold Puts	$ 44.50	$ 44.64	$ 44.64	$ 46.88
%	63%	66%	66%	43%
Purchased Puts	$ 54.59	$ 54.81	$ 54.81	$ 57.50
%	63%	66%	66%	43%
Sold Calls	$ 65.52	$ 65.95	$ 65.99	$ 72.50
%	63%	66%	66%	43%

(1) Based on weighted average price (before premiums) assuming average annual production of 99,000 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 spent on our three-way collars is US$1.59/bbl from April 1, 2019 to December 31, 2020.

	NYMEX Natural Gas (US$/Mcf)(1)
	Apr 1, 2019 – Oct 31, 2019
Swaps	
Sold Swaps	$2.85
%	45%

(1) Based on weighted average price (before premiums) assuming average annual production of 99,000 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) ($ millions)	**Three months ended March 31, 2019**	**2018**
Cash gains/(losses):		
Crude oil	$ (2.0)	$ (6.4)
Natural gas	12.5	16.5
Total cash gains/(losses)	$ 10.5	$ 10.1
Non-cash gains/(losses):		
Crude oil	$ (86.9)	$ (29.9)
Natural gas	(8.5)	(0.7)
Total non-cash gains/(losses)	$ (95.4)	$ (30.6)
Total gains/(losses)	$ (84.9)	$ (20.5)

(Per BOE)	**Three months ended March 31, 2019**	**2018**
Total cash gains/(losses)	$ 1.32	$ 1.33
Total non-cash gains/(losses)	(11.97)	(3.99)
Total gains/(losses)	$ (10.65)	$ (2.66)

During the first quarter of 2019, we realized cash losses of $2.0 million on our crude oil contracts and cash gains of $12.5 million on our natural gas contracts. In comparison, during the first quarter of 2018, we realized cash losses of $6.4 million on our crude oil contracts and cash gains of $16.5 million on our natural gas contracts. Cash losses on our crude oil contracts were primarily due to crude oil prices rising above the swap level. Cash gains on our natural gas contracts were primarily due to natural gas prices falling below the swap level and the put strike price on our collars.

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 the end of the first quarter of 2019, the fair value of our crude oil contracts was in a net liability position of $6.4 million and the fair value of our natural gas contracts was in a net asset position of $2.4 million. For the three months ended March 31, 2019, the change in the fair value of our crude oil contracts and natural gas contracts represented losses of $86.9 million and $8.5 million, respectively.

Revenues

($ millions)	**Three months ended March 31, 2019**	**2018**
Oil and natural gas sales	$ 356.4	$ 328.5
Royalties	(68.9)	(63.5)
Oil and natural gas sales, net of royalties	$ 287.5	$ 265.0

Oil and natural gas sales, net of royalties, for the three months ended March 31, 2019 were $287.5 million, an increase of 8% from the same period in 2018. The increase in revenue was a result of higher liquids production and higher natural gas realized prices.

Royalties and Production Taxes

($ millions, except per BOE amounts)	**Three months ended March 31, 2019**	**2018**
Royalties	$ 68.9	$ 63.5
Per BOE	$ 8.65	$ 8.30
Production taxes	$ 14.6	$ 16.1
Per BOE	$ 1.83	$ 2.11
Royalties and production taxes	$ 83.5	$ 79.6
Per BOE	$ 10.48	$ 10.41
Royalties and production taxes (% of oil and natural gas sales)	23%	24%

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 months ended

March 31, 2019, royalties and production taxes increased to $83.5 million from $79.6 million for the same period in 2018, primarily due to higher U.S. crude oil and natural gas sales.

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

Operating Expenses

	Three months ended March 31,	
($ millions, except per BOE amounts)	2019	2018
Cash operating expenses	$ 69.8	$ 53.8
Per BOE	$ 8.75	$ 7.02

For the three months ended March 31, 2019, operating expenses were $69.8 million or $8.75/BOE, compared to our annual guidance of $8.00/BOE, representing an increase of $16.0 million from the same period in 2018. The increase is mainly attributable to our higher crude oil production as our liquids weighting increased to 51% from 49% in the prior year, higher well service activity on our crude oil properties and the effects of a weaker Canadian dollar in 2019.

With production growing for the remainder of the year, we are maintaining our annual operating cost guidance of $8.00/BOE.

Transportation Costs

	Three months ended March 31,	
($ millions, except per BOE amounts)	2019	2018
Transportation costs	$ 31.3	$ 26.9
Per BOE	$ 3.92	$ 3.52

For the three months ended March 31, 2019, transportation costs were $31.3 million or $3.92/BOE, compared to our annual guidance of $4.00/BOE. During the same period in 2018, transportation costs were $26.9 million or $3.52/BOE. The increase is due to the increase in our U.S. crude oil production and a weaker Canadian dollar when compared to the prior period.

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.

	Three months ended March 31, 2019		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	48,909 BOE/day	238,044 Mcfe/day	88,583 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 59.51	$ 4.41	$ 44.70
Royalties and production taxes	(14.92)	(0.83)	(10.48)
Cash operating expenses	(13.96)	(0.39)	(8.75)
Transportation costs	(2.75)	(0.90)	(3.92)
Netback before hedging	$ 27.88	$ 2.29	$ 21.55
Cash hedging gains/(losses)	(0.45)	0.59	1.32
Netback after hedging	$ 27.43	$ 2.88	$ 22.87
Netback before hedging ($ millions)	$ 122.7	$ 49.1	$ 171.8
Netback after hedging ($ millions)	$ 120.8	$ 61.5	$ 182.3

Netbacks by Property Type	Three months ended March 31, 2018 Crude Oil	Natural Gas	Total
Average Daily Production	44,050 BOE/day	246,180 Mcfe/day	85,080 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 62.99	$ 3.56	$ 42.91
Royalties and production taxes	(16.47)	(0.65)	(10.41)
Cash operating expenses	(10.79)	(0.50)	(7.02)
Transportation costs	(2.07)	(0.84)	(3.52)
Netback before hedging	$ 33.66	$ 1.57	$ 21.96
Cash hedging gains/(losses)	(1.61)	0.75	1.33
Netback after hedging	$ 32.05	$ 2.32	$ 23.29
Netback before hedging ($ millions)	$ 133.4	$ 34.8	$ 168.2
Netback after hedging ($ millions)	$ 127.0	$ 51.3	$ 178.3

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

Crude oil netbacks before hedging for the three months ended March 31, 2019 were lower compared to the same period in 2018 primarily due to weaker realized prices and higher operating and transportation expenses. Natural gas netbacks before hedging were higher for the first quarter of 2019 compared to the same period in 2018 mainly due to higher realized prices. For the three months ended March 31, 2019, our crude oil properties accounted for 71% of our total netback before hedging, compared to 79% during the same period 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 March 31, 2019	2018
Cash:		
G&A expense	$ 12.3	$ 13.2
Share-based compensation expense	1.3	1.9
Non-Cash:		
Share-based compensation expense	8.1	9.1
Equity swap loss/(gain)	(0.1)	(1.0)
G&A expense	0.1	—
Total G&A expenses	$ 21.7	$ 23.2

(Per BOE)	Three months ended March 31, 2019	2018
Cash:		
G&A expense	$ 1.55	$ 1.72
Share-based compensation expense	0.17	0.25
Non-Cash:		
Share-based compensation expense	1.01	1.19
Equity swap loss/(gain)	(0.01)	(0.13)
G&A expense	0.01	—
Total G&A expenses	$ 2.73	$ 3.03

For the three months ended March 31, 2019, cash G&A expenses were $12.3 million or $1.55/BOE compared to $13.2 million or $1.72/BOE for the same period in 2018. Cash G&A expenses were essentially flat but decreased on a per BOE basis compared to the same period in 2018 due to higher production.

During the first quarter of 2019, we reported cash SBC expense of $1.3 million due to the grant of additional deferred share units and the increase in our share price on outstanding deferred share units. In comparison, during the same period of 2018, we recorded cash SBC expense of $1.9 million. We recorded non-cash SBC expense of $8.1 million or $1.01/BOE in the first quarter of 2019, a decrease from an expense of $9.1 million or $1.19/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. In the first quarter we recorded a non-cash mark-to-market gain of $0.1 million on these hedges due to the increase in our share price. We had 195,000 units outstanding, hedged at a weighted average price of $20.60 per share at March 31, 2019.

We are maintaining our annual cash G&A guidance of $1.50/BOE.

Interest Expense

For the three months ended March 31, 2019, we recorded total interest expense of $8.4 million, compared to $9.1 million for the same period in 2018. The decrease in interest expense for the three month period ended March 31, 2019 was primarily due to the repayment of a portion of our 2009 senior notes which carry a higher coupon rate, offset by the impact of a weaker Canadian dollar on our U.S. dollar denominated interest expense.

At March 31, 2019, we were undrawn on our $800 million bank credit facility and our debt balance consisted of fixed interest rates, 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 March 31,	
($ millions)	**2019**	**2018**
Realized:		
Foreign exchange (gain)/loss on settlements	$ (0.1)	$ 0.1
Translation of U.S. dollar cash held in Canada (gain)/loss	5.2	(7.3)
Unrealized (gain)/loss	(17.1)	17.6
Total foreign exchange (gain)/loss	$ (12.0)	$ 10.4
USD/CDN average exchange rate	1.33	1.26
USD/CDN period end exchange rate	1.33	1.29

For the three months ended March 31, 2019, we recorded a foreign exchange gain of $12.0 million compared to losses of $10.4 million for the same period in 2018. Realized gains and losses relate primarily to day-to-day transactions recorded in foreign currencies along with the translation of our U.S. dollar denominated cash held in Canada, while unrealized gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period end. Comparing the period end exchange rate at March 31, 2019 to December 31, 2018, the Canadian dollar strengthened relative to the U.S. dollar, resulting in an unrealized gain of $17.1 million. See Note 13 to the Interim Financial Statements for further details.

Capital Investment

	Three months ended March 31,	
($ millions)	**2019**	**2018**
Capital spending[(1)]	$ 160.8	$ 151.5
Office capital[(1)]	1.1	1.4
Line fill	5.1	—
Sub-total	167.0	152.9
Property and land acquisitions	$ 3.0	$ 12.3
Property divestments	(0.5)	(7.0)
Sub-total	2.5	5.3
Total	$ 169.5	$ 158.2

(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 months ended March 31, 2019 totaled $160.8 million compared to $151.5 million for the same period in 2018. The increase in spending is in line with our strategy to deliver production and liquids growth through 2019. During the first quarter of 2019, we spent $128.1 million on our U.S. crude oil properties, $15.2 million on our Marcellus natural gas assets and $14.7 million on our Canadian waterflood properties. For the three months ended March 31, 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 first quarter, we completed $3.0 million in property and land acquisitions compared to $12.3 million for the same period in 2018 which included minor acquisitions of leases and undeveloped land. Property divestments for the three months ended March 31, 2019 were $0.5 million compared to $7.0 million for the same period in 2018 which primarily related to an acreage swap in North Dakota and the divestment of non-core properties in Northwestern Alberta.

We are narrowing our 2019 annual capital spending guidance range to $590 million – $630 million, following the continued optimization of our operational plans in North Dakota.

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

($ millions, except per BOE amounts)	Three months ended March 31, 2019	2018
DD&A expense	$ 75.9	$ 64.0
Per BOE	$ 9.52	$ 8.36

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three months ended March 31, 2019, DD&A increased compared to the same period in 2018, as a result of additional U.S. production with higher depletion rates and a weaker Canadian dollar.

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 5.56%, to be $127.9 million at March 31, 2019, compared to 5.59% and $126.1 million at December 31, 2018. For the three months ended March 31, 2019, asset retirement obligation settlements were $5.4 million compared to $3.3 million during the same period 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 March 31, 2019, our total lease liability was $65.0 million. In addition, ROU assets of $64.9 million were recorded, which equals lease liabilities less non-cash lease incentives. See Note 3(a) and Note 10 to the Interim Financial Statements for further details.

Income Taxes

($ millions)	Three months ended March 31, 2019	2018
Current tax expense/(recovery)	$ (5.5)	$ 0.1
Deferred tax expenses/(recovery)	(17.9)	12.4
Total tax expense/(recovery)	$ (23.4)	$ 12.5

We recorded a total tax recovery of $23.4 million during the first quarter of 2019, compared to a $12.5 million expense for the same period in 2018. The recovery in 2019 primarily relates to lower net income, as a result of higher unrealized commodity derivative losses, compared to the same period in 2018. The current tax recovery of $5.5 million in 2019 primarily relates to the reversal of the reserve recorded at December 31, 2017 for the sequestered portion of our U.S. AMT refund as the U.S. federal government announced in the first quarter of 2019 that they do not intend to sequester any portion of the AMT refund. See Note 14 to the Interim Financial Statements for further details.

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage, including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging, share repurchases and dividend levels. We also assess our leverage relative to our most restrictive debt covenant 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 March 31, 2019, our senior debt to adjusted EBITDA ratio was 0.9x and our net debt to adjusted funds flow ratio was 0.5x. Although it is not included in our debt covenants, the net debt to adjusted funds flow ratio is often used by investors and analysts to evaluate our liquidity.

Total debt net of cash at March 31, 2019 was $363.8 million, an increase of 9% compared to $333.5 million at December 31, 2018. Total debt was comprised of $682.8 million of senior notes less $319.0 million in cash. At March 31, 2019, we were undrawn on our $800 million bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, was 103% for the three months ended March 31, 2019, consistent with the same period in 2018.

For the three months ended March 31, 2019, the Company repurchased and cancelled approximately 1.7 million shares under our previous and current NCIB for a total cost of $19.8 million.

Our working capital deficiency, excluding cash and current derivative financial assets and liabilities, increased to $161.6 million at March 31, 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, adjusted funds flow and our bank credit facility. We have sufficient liquidity to meet our financial commitments, as disclosed under "Commitments" in the Annual MD&A.

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

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

Covenant Description		March 31, 2019
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	0.9x
Total debt to adjusted EBITDA (1)	4.0x	0.9x
Total debt to capitalization	50%	19%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	0.9x
Senior debt to consolidated present value of total proved reserves(3)	60%	20%
	Minimum Ratio	
Adjusted EBITDA to interest (1)	4.0x	21.5x

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 March 31, 2019 was $166.4 million and $777.6 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

	Three months ended March 31,	
($ millions, except per share amounts)	2019	2018
Dividends to shareholders(1)	$ 7.2	$ 7.3
Per weighted average share (Basic)	$ 0.03	$ 0.03

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

During the three months ended March 31, 2019, we reported total dividends of $7.2 million or $0.03 per share compared to $7.3 million or $0.03 per share for the same period in 2018.

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

Shareholders' Capital

	Three months ended March 31,	
	2019	2018
Share capital ($ millions)	$ 3,317.9	$ 3,411.9
Common shares outstanding (thousands)	238,243	244,773
Weighted average shares outstanding – basic (thousands)	238,922	243,874
Weighted average shares outstanding – diluted (thousands)	241,298	249,191

For the three months ended March 31, 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 three months ended March 31, 2019, no shares were issued pursuant to our stock option plan, resulting in no additional share capital (2018 – 104,622; $0.1 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. Subject to exceptions for block purchases, the Company will limit daily purchases of common shares on the TSX in connection with the NCIB to no more than 25% (270,933 common shares) of the average daily trading volume of the common shares on the TSX (1,083,735 common shares) during any trading day. Purchases under the NCIB will be made through open market purchases at market price, as well as by other means as may be permitted by applicable securities regulatory authorities, including private agreements. Common shares purchased under the NCIB will be cancelled. Shareholders may obtain a copy of the Company's notice to the TSX to renew its NCIB, without charge, by contacting the Corporate Secretary of the Company at Suite 3000, 333 - 7th Avenue S.W., Calgary, Alberta, T2P 2Z1, telephone (403) 298-2200.

During the three months ended March 31, 2019, the Company repurchased 1,732,038 common shares under the previous and current NCIB at an average price of $11.43 per share, for total consideration of $19.8 million. Of the amount paid, $24.1 million was charged to share capital and $4.3 million was credited to accumulated deficit. Subsequent to the quarter and up to May 8, 2019, the Company repurchased 1,259,832 common shares under the NCIB at an average price of $11.86 per share, for total consideration of $15.0 million.

At May 8, 2019, we had 236,983,232 common shares outstanding. In addition, an aggregate of 8,572,694 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

	Three months ended March 31, 2019			Three months ended March 31, 2018		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	8,998	32,107	41,105	9,513	27,930	37,443
Natural gas liquids (bbls/day)	984	3,399	4,383	1,247	2,838	4,085
Natural gas (Mcf/day)	24,348	234,220	258,568	33,132	228,178	261,310
Total average daily production (BOE/day)	14,040	74,543	88,583	16,282	68,798	85,080
Pricing[2]						
Crude oil (per bbl)	$ 59.07	$ 68.66	$ 66.56	$ 52.82	$ 75.41	$ 69.67
Natural gas liquids (per bbl)	35.89	14.30	19.15	45.11	20.66	28.13
Natural gas (per Mcf)	4.64	4.35	4.38	3.12	3.56	3.50
Capital Expenditures						
Capital spending	$ 17.5	$ 143.3	$ 160.8	$ 13.2	$ 138.3	$ 151.5
Acquisitions	1.0	2.0	3.0	1.1	11.2	12.3
Divestments	(0.1)	(0.4)	(0.5)	(0.9)	(6.1)	(7.0)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 61.8	$ 294.6	$ 356.4	$ 60.7	$ 267.8	$ 328.5
Royalties	(8.9)	(60.0)	(68.9)	(9.9)	(53.6)	(63.5)
Production taxes	(0.6)	(14.0)	(14.6)	(0.8)	(15.3)	(16.1)
Cash operating expenses	(21.0)	(48.8)	(69.8)	(20.6)	(33.2)	(53.8)
Transportation costs	(2.7)	(28.6)	(31.3)	(3.0)	(23.9)	(26.9)
Netback before hedging	$ 28.6	$ 143.2	$ 171.8	$ 26.4	$ 141.8	$ 168.2
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 84.9	$ —	$ 84.9	$ 20.5	$ —	$ 20.5
General and administrative expense[4]	13.2	8.5	21.7	15.4	7.8	23.2
Current income tax expense/(recovery)	—	(5.5)	(5.5)	—	0.1	0.1

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See “Non-GAAP Measures” section in this MD&A.
(4) Includes share-based compensation 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				
First Quarter	$ 287.5	$ 19.2	$ 0.08	$ 0.08
Total 2019	$ 287.5	$ 19.2	$ 0.08	$ 0.08
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, decreased in the first quarter of 2019 compared to the fourth quarter of 2018 due to lower production volumes. Net income decreased in the first quarter of 2019 due to unrealized losses on commodity derivative instruments, compared to a significant unrealized gain during the fourth quarter of 2018.

Oil and natural gas sales, net of royalties, improved in 2018 compared to 2017 due to an increase in realized commodity prices and a higher weighting of crude oil and natural gas liquids as a proportion of total 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 increasing our annual average production guidance to 97,000 – 101,000 BOE/day and revising our average annual crude oil and natural gas liquids guidance to 53,500 – 56,000 bbls/day. In addition, we expect second quarter average production of 97,500 – 100,000 BOE/day, with average crude oil and natural gas liquids production of 51,500 – 53,000 bbls/day.

We are narrowing our 2019 capital spending guidance to $590 – $630 million from our previous range of $565 – $635 million.

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

Summary of 2019 Expectations	Target
Capital spending	$590 - $630 million (from $565 - $635 million)
Average annual production	97,000 - 101,000 BOE/day (from 94,000 - 100,000 BOE/day)
Average annual crude oil and natural gas liquids production	53,500 - 56,000 bbls/day (from 52,500 - 56,000 bbls/day)
Second quarter average production	97,500 - 100,000 BOE/day
Second quarter average crude oil and natural gas liquids production	51,500 - 53,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	25%
Operating expenses	$8.00/BOE
Transportation costs	$4.00/BOE
Cash G&A expenses	$1.50/BOE

2019 Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(4.00)/bbl
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.30)/Mcf

(1) Excludes transportation costs.

NON-GAAP MEASURES

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

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

Calculation of Netback	Three months ended March 31,	
($ millions)	2019	2018
Oil and natural gas sales	$ 356.4	$ 328.5
Less:		
Royalties	(68.9)	(63.5)
Production taxes	(14.6)	(16.1)
Cash operating expenses	(69.8)	(53.8)
Transportation costs	(31.3)	(26.9)
Netback before hedging	$ 171.8	$ 168.2
Cash gains/(losses) on derivative instruments	10.5	10.1
Netback after hedging	$ 182.3	$ 178.3

"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 net cash 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 March 31,	
($ millions)	2019	2018
Cash flow from operating activities	$ 109.0	$ 159.3
Asset retirement obligation expenditures	5.4	3.3
Changes in non-cash operating working capital	54.4	(7.4)
Adjusted funds flow	$ 168.8	$ 155.2

"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 March 31,	
($ millions)	2019	2018
Adjusted funds flow	$ 168.8	$ 155.2
Capital spending	(160.8)	(151.5)
Free cash flow	$ 8.0	$ 3.7

"Adjusted net income" is used by Enerplus and is useful to investors and securities analyst 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 and the tax effect of these items.

Calculation of Adjusted Net Income	Three months ended March 31,	
($ millions)	2019	2018
Net income/(loss)	$ 19.2	$ 29.6
Unrealized derivative instrument (gain)/loss	95.3	29.6
Unrealized foreign exchange (gain)/loss	(17.1)	17.6
Tax effect on above items	(24.9)	(8.4)
Adjusted net income	$ 72.5	$ 68.4

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

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

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

Calculation of Adjusted Payout Ratio	Three months ended March 31,	
($ millions)	2019	2018
Dividends	$ 7.2	$ 7.3
Capital, office expenditures and line fill	167.0	152.9
Sub-total	$ 174.2	$ 160.2
Adjusted funds flow	$ 168.8	$ 155.2
Adjusted payout ratio (%)	103%	103%

"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)	March 31, 2019
Net income/(loss)	$ 367.8
Add:	
Interest	36.1
Current and deferred tax expense/(recovery)	67.3
DD&A and asset impairment	316.1
Other non-cash charges[(2)]	(9.7)
Adjusted EBITDA	$ 777.6

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at March 31, 2019 include the three months ended March 31, 2019 and the second, third and 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", "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 March 31, 2019, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on January 1, 2019 and ended March 31, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our current Annual Information Form ("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 2019, including second quarter, 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 current NCIB and share repurchases thereunder; 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$60.00/bbl, a NYMEX price of US$2.75/Mcf, and a USD/CDN exchange rate of 1.33. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued low commodity prices environment or further volatility in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our AIF, 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	March 31, 2019	December 31, 2018
Assets			
Current Assets			
Cash and cash equivalents		$ 318,996	$ 363,327
Accounts receivable	4	153,805	145,206
Income tax receivable	14	57,746	55,172
Derivative financial assets	16	5,541	59,258
Other current assets		6,822	8,928
		542,910	631,891
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	5	1,368,294	1,293,941
Other capital assets, net	5	18,468	13,130
Property, plant and equipment		1,386,762	1,307,071
Right-of-use assets	3,10	64,934	—
Goodwill		650,498	654,799
Derivative financial assets	16	4,252	32,220
Deferred income tax asset	14	477,274	465,124
Income tax receivable	14	28,470	27,195
Total Assets		$ 3,155,100	$ 3,118,300
Liabilities			
Current liabilities			
Accounts payable	7	$ 301,545	$ 290,045
Dividends payable		2,383	2,395
Current portion of long-term debt	8	59,368	60,001
Derivative financial liabilities	16	15,552	1,909
Current portion of lease liabilities	3,10	16,647	—
		395,495	354,350
Long-term debt	8	623,399	636,849
Asset retirement obligation	9	127,937	126,112
Lease liabilities	3,10	48,377	—
		799,713	762,961
Total Liabilities		1,195,208	1,117,311
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value Issued and outstanding: March 31, 2019 – 238 million shares December 31, 2018 – 239 million shares	15	3,317,855	3,337,608
Paid-in capital		45,209	46,524
Accumulated deficit		(1,755,757)	(1,772,084)
Accumulated other comprehensive income/(loss)		352,585	388,941
		1,959,892	2,000,989
Total Liabilities & Shareholders' Equity		$ 3,155,100	$ 3,118,300
Commitments and Contingencies	17		
Subsequent events	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 March 31, 2019	2018
Revenues			
Oil and natural gas sales, net of royalties	11	$ 287,452	$ 265,020
Commodity derivative instruments gain/(loss)	16	(84,867)	(20,464)
		202,585	244,556
Expenses			
Operating		69,793	53,761
Transportation		31,291	26,921
Production taxes		14,615	16,135
General and administrative	12	21,710	23,224
Depletion, depreciation and accretion		75,911	64,046
Interest		8,393	9,103
Foreign exchange (gain)/loss	13	(12,026)	10,371
Other expense/(income)		(2,862)	(1,183)
		206,825	202,378
Income/(Loss) before taxes		(4,240)	42,178
Current income tax expense/(recovery)	14	(5,530)	66
Deferred income tax expense/(recovery)	14	(17,868)	12,475
Net Income/(Loss)		$ 19,158	$ 29,637
Other Comprehensive Income/(Loss)			
Change in cumulative translation adjustment		(36,356)	34,368
Total Comprehensive Income/(Loss)		$ (17,198)	$ 64,005
Net income/(Loss) per share			
Basic	15	$ 0.08	$ 0.12
Diluted	15	$ 0.08	$ 0.12

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 March 31, 2019	2018
Share Capital		
Balance, beginning of period	$ 3,337,608	$ 3,386,946
Purchase of common shares under Normal Course Issuer Bid	(24,159)	—
Share-based compensation – treasury settled	4,406	23,389
Stock Option Plan – cash	—	1,429
Stock Option Plan – exercised	—	114
Balance, end of period	$ 3,317,855	$ 3,411,878
Paid-in Capital		
Balance, beginning of period	$ 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	8,043	9,079
Stock Option Plan – exercised	—	(114)
Balance, end of period	$ 45,209	$ 60,951
Accumulated Deficit		
Balance, beginning of period	$ (1,772,084)	$ (2,124,676)
Purchase of common shares under Normal Course Issuer Bid	4,331	—
Net income/(loss)	19,158	29,637
Dividends declared ($0.01 per share)	(7,162)	(7,320)
Balance, end of period	$ (1,755,757)	$ (2,102,359)
Accumulated Other Comprehensive Income/(Loss)		
Balance, beginning of period	$ 388,941	$ 263,124
Change in cumulative translation adjustment	(36,356)	34,368
Balance, end of period	$ 352,585	$ 297,492
Total Shareholders' Equity	$ 1,959,892	$ 1,667,962

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 March 31, 2019	2018
Operating Activities			
Net income/(loss)		$ 19,158	$ 29,637
Non-cash items add/(deduct):			
Depletion, depreciation and accretion		75,911	64,046
Changes in fair value of derivative instruments	16	95,328	29,622
Deferred income tax expense/(recovery)	14	(17,868)	12,475
Foreign exchange (gain)/loss on debt and working capital	13	(17,104)	17,649
Share-based compensation and general and administrative	12,15	8,134	9,079
Translation of U.S. dollar cash held in Canada	13	5,196	(7,346)
Asset retirement obligation expenditures	9	(5,390)	(3,331)
Changes in non-cash operating working capital	18	(54,414)	7,469
Cash flow from/(used in) operating activities		108,951	159,300
Financing Activities			
Proceeds from the issuance of shares	15	—	1,429
Purchase of common shares under Normal Course Issuer Bid	15	(19,828)	—
Share-based compensation – cash settled (tax withholding)	15	(4,952)	—
Dividends	15,18	(7,174)	(7,294)
Cash flow from/(used in) financing activities		(31,954)	(5,865)
Investing Activities			
Capital and office expenditures	18	(111,795)	(108,212)
Property and land acquisitions		(2,981)	(6,190)
Property divestments		422	888
Cash flow from/(used in) investing activities		(114,354)	(113,514)
Effect of exchange rate changes on cash and cash equivalents		(6,974)	9,926
Change in cash and cash equivalents		(44,331)	49,847
Cash and cash equivalents, beginning of period		363,327	346,548
Cash and cash equivalents, end of period		$ 318,996	$ 396,395

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 months ended March 31, 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 Condensed Consolidated Financial Statements should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2018. There are no differences in the use of estimates or judgments between these interim Condensed Consolidated Financial Statements and the 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 ("ROU") 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 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 lease payments 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 continues to assess the impact it will have 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 amount of the reporting unit exceeds the reporting unit's fair value. The updated guidance is effective January 1, 2020, and will be applied prospectively. Enerplus does not expect to early adopt the standard. The amended standard may affect goodwill impairment tests past the adoption date, the impact of which is not known.

4) ACCOUNTS RECEIVABLE

($ thousands)	March 31, 2019	December 31, 2018
Accrued revenue	$ 125,969	$ 118,821
Accounts receivable – trade	31,675	30,252
Allowance for doubtful accounts	(3,839)	(3,867)
Total accounts receivable, net of allowance for doubtful accounts	$ 153,805	$ 145,206

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

As of March 31, 2019 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties[(1)]	$ 14,797,051	$ (13,428,757)	$ 1,368,294
Other capital assets	121,349	(102,881)	18,468
Total PP&E	$ 14,918,400	$ (13,531,638)	$ 1,386,762

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 three months ended March 31, 2019 and 2018.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from March 31, 2018 through March 31, 2019:

Period	WTI Crude Oil US$/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	Exchange Rate US$/CDN$
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
Q2 2018	57.67	67.77	2.92	1.27
Q1 2018	53.49	64.57	3.00	1.28

7) ACCOUNTS PAYABLE

($ thousands)	March 31, 2019	December 31, 2018
Accrued payables	$ 131,070	$ 115,388
Accounts payable – trade	170,475	174,657
Total accounts payable	$ 301,545	$ 290,045

8) DEBT

($ thousands)	March 31, 2019	December 31, 2018
Current:		
Senior notes	$ 59,368	$ 60,001
Long-term:		
Bank credit facility	—	—
Senior notes	623,399	636,849
Total debt	$ 682,767	$ 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	$ 140,166
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2019	4.34%	CDN$30,000	CDN$30,000	30,000
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	26,698
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$298,000	397,800
June 18, 2009	June 18 and Dec 18	3 equal annual installments June 18, 2019 - 2021	7.97%	US$225,000	US$66,000	88,103
					Total carrying value	$ 682,767

9) ASSET RETIREMENT OBLIGATION

($ thousands)	Three months ended March 31, 2019	Year ended December 31, 2018
Balance, beginning of year	$ 126,112	$ 117,736
Change in estimates	5,279	16,755
Property acquisitions and development activity	483	1,565
Divestments	(8)	(4,585)
Settlements	(5,390)	(11,263)
Accretion expense	1,461	5,904
Balance, end of period	$ 127,937	$ 126,112

Enerplus has estimated the present value of its asset retirement obligation to be $127.9 million at March 31, 2019 based on a total undiscounted liability of $345.2 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 5.56% (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 includes 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 March 31, 2019
Weighted average remaining lease term (years)	
Operating leases	4.6
Weighted average discount rate	
Operating leases	4.1%

The components of lease expense for the three months ended March 31, 2019 are as follows:

($ thousands)		Lease Expense	Financial Statement Presentation
Operating lease expense(1)	$	4,584	PP&E
Operating lease expense(1)		2,788	Operating expense
Operating lease expense(1)		1,627	G&A expense
Sublease income		(244)	G&A expense
Total	$	8,755	

(1) Includes short-term and variable lease costs of $4.4 million.

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

Maturity of Lease Liabilities

($ thousands)		Operating Leases
2019	$	14,292
2020		19,328
2021		13,758
2022		7,390
After 2022		16,990
Total lease payments	$	71,758
Less imputed interest		(6,734)
Total discounted lease payments	$	65,024
Current portion of lease liabilities	$	16,647
Non-current portion of lease liabilities	$	48,377

Supplemental cash flow information related to leases are as follows:

($ thousands)		Three months ended March 31, 2019
Cash amounts paid to settle lease liabilities:		
Operating cash flow from operating leases	$	4,506
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$	18,863

11) OIL AND NATURAL GAS SALES

($ thousands)	Three months ended March 31, 2019	2018
Oil and natural gas sales	$ 356,376	$ 328,552
Royalties[1]	(68,924)	(63,532)
Oil and natural gas sales, net of royalties	$ 287,452	$ 265,020

(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 months ended March 31, 2019 and 2018 are as follows:

Three months ended March 31, 2019 ($ thousands)	Total revenue, net of royalties[1]	Crude oil[2]	Natural gas[2]	Natural gas liquids[2]	Other[3]
Canada	$ 52,895	$ 39,417	$ 10,367	$ 2,486	$ 625
United States	234,557	157,841	73,157	3,559	—
Total	$ 287,452	$ 197,258	$ 83,524	$ 6,045	$ 625

Three months ended March 31, 2018 ($ thousands)	Total revenue, net of royalties[1]	Crude oil[2]	Natural gas[2]	Natural gas liquids[2]	Other[3]
Canada	$ 50,774	$ 35,985	$ 9,640	$ 4,059	$ 1,090
United States	214,246	151,224	58,595	4,427	—
Total	$ 265,020	$ 187,209	$ 68,235	$ 8,486	$ 1,090

(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

($ thousands)	Three months ended March 31, 2019	2018
General and administrative expense	$ 12,431	$ 13,205
Share-based compensation expense	9,279	10,019
General and administrative expense[1]	$ 21,710	$ 23,224

(1) Includes cash and non-cash amounts.

13) FOREIGN EXCHANGE

($ thousands)	Three months ended March 31, 2019	2018
Realized:		
Foreign exchange (gain)/loss	$ (118)	$ 68
Translation of U.S. dollar cash held in Canada (gain)/loss	5,196	(7,346)
Unrealized:		
Translation of U.S. dollar debt and working capital (gain)/loss	(17,104)	17,649
Foreign exchange (gain)/loss	$ (12,026)	$ 10,371

14) INCOME TAXES

($ thousands)	Three months ended March 31, 2019	2018
Current tax expense/(recovery)		
United States	$ (5,530)	$ 66
Current tax expense/(recovery)	(5,530)	66
Deferred tax expense/(recovery)		
Canada	$ (29,559)	$ (5,510)
United States	11,691	17,985
Deferred tax expense/(recovery)	(17,868)	12,475
Income tax expense/(recovery)	$ (23,398)	$ 12,541

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 $477.3 million at March 31, 2019 (December 31, 2018 – $465.1 million).

At March 31, 2019, the current and non-current income tax receivable included $56.9 million and $28.5 million, respectively, relating to a portion of the U.S. Alternative Minimum Tax ("AMT") refund (December 31, 2018 – $54.4 million and $27.2 million, respectively).

15) SHAREHOLDERS' EQUITY

a) Share Capital

	Three months ended March 31, 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	(1,732)	(24,159)	(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	238,243	$ 3,317,855	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 months ended March 31, 2019 was $7.2 million (2018 – $7.3 million).

On March 21, 2019, Enerplus renewed its Normal Course Issuer Bid ("NCIB") to continue to repurchase shares through the facilities of the Toronto Stock Exchange, 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 is allocated to accumulated deficit. During the three months ended March 31, 2019, the Company repurchased 1,732,038 common shares under the previous and current NCIB at an average price of $11.43 per share, for total consideration of $19.8 million. Of the amount paid, $24.1 million was charged to share capital and $4.3 million was credited to accumulated deficit.

Subsequent to the quarter, and up to May 8, 2019, the Company repurchased an additional 1,259,832 common shares under the NCIB at an average price of $11.86 per share, for total consideration of $15.0 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 March 31,	
($ thousands)	**2019**	**2018**
Cash:		
Long-term incentive plans (recovery)/expense	$ 1,337	$ 1,946
Non-cash:		
Long-term incentive plans	8,043	9,079
Equity swap (gain)/loss	(101)	(1,006)
Share-based compensation expense	$ 9,279	$ 10,019

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 three months ended March 31, 2019:

For the three months ended March 31, 2019	Cash-settled LTI plans	Equity-settled LTI plans		Total
(thousands of units)	DSU	PSU[1]	RSU	
Balance, beginning of year	391	1,371	1,753	3,515
Granted	96	797	835	1,728
Vested	—	—	(1,007)	(1,007)
Forfeited	—	—	(11)	(11)
Balance, end of period	487	2,168	1,570	4,225

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

Cash-settled LTI Plans

For the three months ended March 31, 2019, the Company recorded cash share-based compensation expense of $1.3 million (March 31, 2018 – $1.9 million). For the three months ended March 31, 2019, the Company made cash payments of nil related to its cash-settled plans (March 31, 2018 – nil).

As of March 31, 2019, a liability of $5.4 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 March 31, 2019 ($ thousands, except for years)	PSU[1]	RSU	Total
Cumulative recognized share-based compensation expense	$ 22,392	$ 7,590	$ 29,982
Unrecognized share-based compensation expense	18,819	12,129	30,948
Fair value	$ 41,211	$ 19,719	$ 60,930
Weighted-average remaining contractual term (years)	2.1	1.8	

(1) Includes estimated performance multipliers.

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

Cash paid by Enerplus when directly withholding shares for tax-withholding purposes have been classified as a financing activity in the Condensed Consolidated Statements of Cash Flows. As of March 31, 2019, $5.0 million was settled (2018 – nil).

ii) Stock Option Plan

At March 31, 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 three months ended March 31, 2019:

Period ended March 31, 2019	Number of Options (thousands)	Weighted Average Exercise Price
Options outstanding, beginning of year	4,131	$ 17.12
Forfeited	(31)	17.74
Expired	(1,436)	22.79
Options outstanding, end of period	2,664	$ 14.05
Options exercisable, end of period	2,664	$ 14.05

At March 31, 2019, Enerplus had 2,663,579 options that were exercisable at a weighted average exercise price of $14.05 with a weighted average remaining contractual term of 0.8 years, giving an aggregate intrinsic value of nil (March 31, 2018 – 1.5 years and $2.2 million). The intrinsic value of options exercised for the three months ended March 31, 2019 was nil (March 31, 2018 – $0.2 million).

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

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

	Three months ended March 31,	
(thousands, except per share amounts)	2019	2018
Net income/(loss)	$ 19,158	$ 29,637
Weighted average shares outstanding – Basic	238,922	243,874
Dilutive impact of share-based compensation	2,376	5,317
Weighted average shares outstanding – Diluted	241,298	249,191
Net income/(loss) per share		
Basic	$ 0.08	$ 0.12
Diluted	$ 0.08	$ 0.12

16) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At March 31, 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 March 31, 2019, the senior notes had a carrying value of $682.8 million and a fair value of $686.7 million (December 31, 2018 – $696.9 million and $695.4 million, respectively).

The fair value of derivative contracts and the senior notes are considered a level 2 fair value measurement. 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 months ended March 31, 2019 and 2018:

	Three months ended March 31,		Income Statement
Gain/(Loss) ($ thousands)	2019	2018	Presentation
Electricity Swaps	$ —	$ (16)	Operating expense
Equity Swaps	101	1,006	G&A expense
Commodity Derivative Instruments:			
Oil	(86,929)	(29,855)	Commodity derivative
Gas	(8,500)	(757)	instruments
Total	$ (95,328)	$ (29,622)	

The following table summarizes the income statement effects of Enerplus' commodity derivative instruments:

	Three months ended March 31,	
($ thousands)	2019	2018
Change in fair value gain/(loss)	$ (95,429)	$ (30,612)
Net realized cash gain/(loss)	10,562	10,148
Commodity derivative instruments gain/(loss)	$ (84,867)	$ (20,464)

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

	March 31, 2019			December 31, 2018		
	Assets		Liabilities	Assets		Liabilities
($ thousands)	Current	Long-term	Current	Current	Long Term	Current
Equity Swaps	$ —	$ —	$ 1,808	$ —	$ —	$ 1,909
Commodity Derivative Instruments:						
Oil	3,097	4,252	13,744	48,314	32,220	—
Gas	2,444	—	—	10,944	—	—
Total	$ 5,541	$ 4,252	$ 15,552	$ 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 derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts subject to a maximum of 80% of forecasted production volumes net of royalties and production taxes.

The following tables summarize the Corporation's price risk management positions at May 8, 2019:

Crude Oil Instruments:

Instrument Type(1)(2)	bbls/day	US$/bbl
Apr 1, 2019 – Jun 30, 2019		
WTI Purchased Put	23,500	54.59
WTI Sold Call	23,500	65.52
WTI Sold Put	23,500	44.50
WCS Differential Swap	1,500	(14.83)
WTI – Brent Swap	2,700	(8.10)
Jul 1, 2019 – Sep 30, 2019		
WTI Purchased Put	24,500	54.81
WTI Sold Call	24,500	65.95
WTI Sold Put	24,500	44.64
WCS Differential Swap	1,500	(14.83)
WTI – Brent Swap	2,700	(8.10)
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 Call	16,000	72.50
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 three way collars is US$1.59/bbl from April 1, 2019 to December 31, 2020.

For the remainder of 2019, Enerplus has physical sales contracts in place for approximately 19,000 bbls/day of Bakken production with fixed differentials averaging approximately US$1.90/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
Apr 1, 2019 – Oct 31, 2019		
NYMEX Swap	90.0	2.85

(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 March 31, 2019, Enerplus did not have any foreign exchange derivatives outstanding.

Interest Rate Risk:

At March 31, 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 in 2019 that effectively fix the future settlement cost on 195,000 shares at a weighted average price of $20.60 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 March 31, 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 March 31, 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 shareholders' 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 March 31, 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 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 March 31,	
($ thousands)	**2019**	**2018**
Accounts receivable	$ (14,179)	$ (6,637)
Other assets	(3,027)	1,621
Accounts payable	(37,208)	12,485
	$ (54,414)	$ 7,469

b) Changes in Other Non-Cash Working Capital

	Three months ended March 31,	
($ thousands)	**2019**	**2018**
Non-cash financing activities(1)	$ (12)	$ 26
Non-cash investing activities(2)	50,101	44,660

(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 March 31,	
($ thousands)	**2019**	**2018**
Income taxes paid/(received)	$ 64	$ (85)
Interest paid	3,259	3,256

BOARD OF DIRECTORS

Elliott Pew(1)(2)
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(3)(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

Glen D. Roane(4)(5)
Corporate Director
Canmore, 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

Blake, Cassels & Graydon LLP
Calgary, Alberta

AUDITORS

KPMG LLP
Calgary, Alberta

TRANSFER AGENT

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

U.S. CO-TRANSFER AGENT

Computershare Trust Company, N.A.
Golden, Colorado

INDEPENDENT RESERVE ENGINEERS

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS

Toronto Stock Exchange: ERF
New York Stock Exchange: ERF

U.S. OFFICE

950 17th Street, Suite 2200
Denver, Colorado 80202

Telephone: 720.279.5500
Fax: 720.279.5550

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
TGP Z4 300L	Price benchmark for Marcellus natural gas delivered into the 300 Leg within Zone 4 of the Tennessee Gas Pipeline system between Tioga and Susquehanna Counties in Pennsylvania
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
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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ERF LISTED ON TMX Toronto Stock Exchange

ERF LISTED NYSE