Q1 2018

First Quarter Report

Three Months Ended March 31, 2018

SELECTED FINANCIAL RESULTS	Three months ended March 31, 2018	2017
Financial (000's)		
Net Income/(Loss)	$ 29,637	$ 76,293
Adjusted Funds Flow[4]	155,162	119,920
Dividends to Shareholders - Declared	7,320	7,242
Debt Outstanding – net of Cash and Restricted Cash	291,978	350,401
Capital Spending	151,472	120,351
Property and Land Acquisitions	12,272	2,536
Property Divestments	6,970	(899)
Net Debt to Adjusted Funds Flow Ratio[4]	0.5x	0.9x
Financial per Weighted Average Shares Outstanding		
Net Income - Basic	$ 0.12	$ 0.32
Net Income - Diluted	0.12	0.31
Weighted Average Number of Shares Outstanding (000's)	243,874	241,285
Selected Financial Results per BOE[1][2]		
Oil and Natural Gas Sales[3]	$ 42.91	$ 36.33
Royalties and Production Taxes	(10.41)	(7.89)
Commodity Derivative Instruments	1.33	0.86
Cash Operating Expenses	(7.02)	(6.57)
Transportation Costs	(3.52)	(3.88)
General and Administrative Expenses	(1.72)	(1.87)
Cash Share-Based Compensation	(0.25)	(0.02)
Interest, Foreign Exchange and Other Expenses	(1.05)	(1.26)
Current Income Tax Recovery/(Expense)	(0.01)	(0.01)
Adjusted Funds Flow[4]	$ 20.26	$ 15.69

SELECTED OPERATING RESULTS	Three months ended March 31, 2018	2017
Average Daily Production[2]		
Crude Oil (bbls/day)	37,443	33,178
Natural Gas Liquids (bbls/day)	4,085	3,158
Natural Gas (Mcf/day)	261,310	291,607
Total (BOE/day)	85,080	84,937
% Crude Oil and Natural Gas Liquids	49%	43%
Average Selling Price [2][3]		
Crude Oil (per bbl)	$ 69.67	$ 57.53
Natural Gas Liquids (per bbl)	28.13	37.76
Natural Gas (per Mcf)	3.50	3.63
Net Wells Drilled	14	15

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

Average Benchmark Pricing	Three months ended March 31, 2018	2017
WTI crude oil (US$/bbl)	$ 62.87	$ 51.92
AECO natural gas– monthly index (CDN$/Mcf)	1.85	2.94
AECO natural gas – daily index (CDN$/Mcf)	2.08	2.69
NYMEX natural gas – last day (US$/Mcf)	3.00	3.32
USD/CDN average exchange rate	1.26	1.32

Share Trading Summary For the three months ended March 31, 2018	CDN[1] - ERF (CDN$)	U.S.[2] - ERF (US$)
High	$ 15.90	$ 12.26
Low	$ 12.18	$ 9.66
Close	$ 14.49	$ 11.26

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

2018 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:

- 2018 adjusted funds flow expected to exceed capital expenditures and dividends by approximately $100 million based on current forward strip pricing
- Strong growth underway with second quarter liquids production expected to average between 48,000 to 50,000 barrels per day
- Well positioned relative to 2018 production guidance including over 30% production growth in North Dakota year-over-year
- First quarter 2018 adjusted funds flow of $155.2 million
- Ended the first quarter of 2018 with a net debt to adjusted funds flow ratio of 0.5 times

"Our plans are well on track to continue to drive competitive, profitable growth while generating robust returns on capital," stated Ian C. Dundas, President and Chief Executive Officer. "With our continued margin expansion resulting from improved pricing realizations and reductions to our cost structure over the last year, we expect to generate meaningful free cash flow in 2018 under current strip prices. Additionally, we expect to deliver over 30% production growth from our high-returning North Dakota asset. Despite the improving crude oil price outlook, we remain committed to our disciplined approach to capital allocation focused on generating full-cycle returns and creating long-term value for our shareholders."

First Quarter Financial and Operational Summary

PRODUCTION

Production in the first quarter of 2018 averaged 85,080 BOE per day, including 41,528 barrels per day of crude oil (90%) and natural gas liquids (10%). As forecast, liquids production was lower compared to the prior quarter primarily due to downtime related to completions activity on adjacent properties and on-stream activity in North Dakota weighted to the back half of the first quarter.

Natural gas production for the first quarter averaged 261 MMcf per day, a 4% increase from the prior quarter primarily due to higher Marcellus production supported by stronger natural gas pricing.

The Company remains well positioned relative to its 2018 production guidance with strong growth underway in the second quarter. Four wells from a high-working interest six-well pad in North Dakota began flowing back at strong initial rates in late April, with the two remaining wells expected on-stream in early May. Based on field estimates, current liquids production is averaging approximately 49,000 barrels per day. Enerplus is expecting second quarter liquids production to average 48,000 to 50,000 barrels per day.

NET INCOME, ADJUSTED FUNDS FLOW AND NETBACK

Enerplus generated net income of $29.6 million in the first quarter of 2018, an increase from $15.3 million in the previous quarter as a result of lower non-cash income tax expense in the first quarter.

Adjusted funds flow was $155.2 million during the first quarter, compared to $199.6 million in the previous quarter which included $50.1 million related to the U.S. Alternative Minimum Tax refund. Adjusted funds flow remained strong in the first quarter supported by higher benchmark oil and natural gas prices and a hedging gain related to the unwinding of a portion of the Company's AECO - NYMEX basis contracts.

Enerplus' netback, before commodity hedging, was $21.97 per BOE in the first quarter of 2018. This represents a 2% increase from the prior quarter and a 22% increase from the same period in 2017.

PRICING REALIZATIONS AND COST STRUCTURE

Enerplus' realized Bakken crude oil price differential averaged US$3.27 per barrel below WTI in the first quarter, weaker than the previous quarter's differential of US$1.61 per barrel largely driven by the 13% increase in average benchmark WTI oil prices quarter-over-quarter. As a result of the recent strength in WTI oil prices and with the current 2018 forward strip at approximately US$65 per barrel, Enerplus is increasing its estimated 2018 average Bakken crude oil price differential to US$3.50 per barrel below WTI, from US$2.50 per barrel below WTI previously.

Enerplus' realized Marcellus natural gas price differential strengthened considerably to US$0.21 per Mcf below NYMEX in the first quarter, an improvement of US$0.60 per Mcf from the prior quarter. This pricing improvement was due to the continued build-out of regional pipeline takeaway capacity as well as the effect of a colder than normal winter, which resulted in price spikes in key consumption regions in the U.S. Enerplus expects its Marcellus differential to increase during the remainder of 2018 as a portion of its sales portfolio is linked to New York markets that are typically weaker during the summer months. Enerplus continues to project an average 2018 differential of US$0.40 per Mcf below NYMEX.

First quarter operating, transportation, and cash general and administrative ("G&A") expenses were all largely in-line with the Company's annual 2018 guidance. First quarter operating expenses averaged $7.02 per BOE, transportation costs averaged $3.52 per BOE, and cash G&A expenses averaged $1.72 per BOE. Enerplus' 2018 guidance for these items remains unchanged.

CAPITAL EXPENDITURES AND BALANCE SHEET POSITION

Exploration and development capital spending in the first quarter was $151.5 million associated with drilling 13.9 net wells and completing and bringing on production 8.9 net wells across the Company. Enerplus' 2018 capital spending guidance of $535 million to $585 million is unchanged.

Enerplus remains in a strong financial position. Total debt net of cash at March 31, 2018 was $292 million. Total debt was comprised of $688.4 million of senior notes outstanding. The Company was undrawn on its $800 million bank credit facility, and had a cash balance of $396.4 million. At March 31, 2018, Enerplus' net debt to adjusted funds flow ratio was 0.5 times.

Average Daily Production(1)

	Three months ended March 31, 2018			
	Crude Oil (Mbbl/d)	**Natural Gas Liquids** (Mbbl/d)	**Natural Gas** (MMcf/d)	**Total** (Mboe/d)
Williston Basin	27.7	2.8	19.8	33.8
Marcellus	—	—	208.4	34.7
Canadian Waterfloods	9.4	0.1	5.0	10.3
Other(2)	0.4	1.1	28.2	6.2
Total	**37.4**	**4.1**	**261.3**	**85.1**

(1) Table may not add due to rounding.
(2) Includes approximately 600 BOE/day of production from Canadian natural gas properties sold in Q1 2018.

Summary of Wells Brought On-Stream(1)

	Three months ended March 31, 2018			
	Operated		**Non Operated**	
	Gross	Net	Gross	Net
Williston Basin	8.0	5.2	—	—
Marcellus	—	—	11.0	1.5
Canadian Waterfloods	2.0	1.9	—	—
Other	—	—	1.0	0.3
Total	**10.0**	**7.1**	**12.0**	**1.8**

(1) Table may not add due to rounding.

Asset Activity

WILLISTON BASIN

Williston Basin production averaged 33,836 BOE per day (82% oil) during the first quarter of 2018, down 14% from the fourth quarter of 2017. This decrease was expected due to downtime related to offset completions and on-stream activity in North Dakota weighted to the back half of the first quarter. First quarter Williston Basin production was comprised of 30,372 BOE per day in North Dakota and 3,464 BOE per day in Montana.

Enerplus brought on-stream eight gross operated wells (65% average working interest) across its acreage at Fort Berthold during the first quarter. The average completed lateral length was 9,000 feet per well and average peak 30-day production rates per well were 1,360 BOE per day (77% oil, on a three-stream basis).

The Company drilled nine gross operated wells (96% average working interest) in the first quarter.

In late April, the Company completed and brought on production four of six planned wells from its Cats pad (91% average working interest). The wells are currently flowing back at strong rates which are tracking the high end of the Company's expectations. The remaining two wells are expected to be on-stream in early May.

The Company continues to run two operated drilling rigs and one dedicated completions crew at its Fort Berthold operations.

MARCELLUS

Marcellus production averaged 208 MMcf per day during the first quarter, an increase from the previous quarter of 8% primarily due to stronger production driven by improved natural gas pricing.

Eleven gross non-operated wells (14% average working interest) were brought on-stream during the quarter. Nine wells had more than 30 days on production as of the date of this news release with an average completed lateral length of 6,340 feet per well and average peak 30-day production rates per well of 14 MMcf per day.

The Company participated in drilling thirteen gross non-operated wells (20% average working interest) during the first quarter.

CANADIAN WATERFLOODS

Canadian waterflood production averaged 10,336 BOE per day (91% oil) during the first quarter, relatively flat to the previous quarter. Enerplus drilled and brought on-stream two wells in southeast Saskatchewan with average peak 30-day production rates per well of 235 barrels of oil per day, exceeding the Company's expectations. At Ante Creek, the construction of two injection pipelines was completed along with two producer-to-injector well conversions. The increased water injection at Ante Creek has helped stabilize decline with oil production remaining relatively flat compared to the fourth quarter. Ante Creek oil volumes are expected to gradually increase during the second half of 2018.

DJ BASIN

Enerplus' first DJ Basin well (Maple 8-67-36-5C) has produced over 85,000 BOE (79% oil) in just over seven months on production. In April, the well averaged approximately 400 BOE per day (73% oil). The Company is continuing delineation activity to test the extent of commerciality across its acreage position with four gross (3.5 net) wells in 2018 testing both the Codell and Niobrara intervals.

2018 Guidance

Enerplus' 2018 guidance is summarized below. The Company has included second quarter 2018 liquids production guidance and revised its estimated 2018 Bakken crude oil price differential to US$3.50 per barrel below WTI from US$2.50 per barrel below WTI previously. All other guidance targets are unchanged.

	Guidance
Capital spending	$535 – $585 million
Q2 2018 crude oil and natural gas liquids production	48,000 – 50,000 bbls/day
Average annual production	86,000 – 91,000 BOE/day
Average annual crude oil and natural gas liquids production	46,000 – 50,000 bbls/day
Average royalty and production tax rate	25%
Operating expense	$7.00/BOE
Transportation expense	$3.60/BOE
Cash G&A expense	$1.65/BOE

2018 Full-Year Differential/Basis Outlook[1]	
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.50)/bbl (from US$(2.50)/bbl)
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.40)/Mcf

(1) Excluding transportation costs.

Risk Management

Enerplus continues to manage price risk through commodity hedging. Using swaps and collar structures, Enerplus has an average of 21,500 barrels per day of crude oil protected for the remainder of 2018 (approximately 67% of forecast crude oil production at the midpoint of guidance, net of royalties), 21,300 barrels per day protected in 2019, and 6,000 barrels per day of crude oil protected in 2020.

For natural gas, Enerplus has 37,800 Mcf per day protected for the remainder of 2018 (approximately 21% of forecast natural gas production at the midpoint of guidance, net of royalties) using collar structures.

Commodity Hedging Detail (As at May 2, 2018)

	WTI Crude Oil (US$/bbl)[1]							NYMEX Natural Gas (US$/Mcf)	
	Apr 1, 2018 – Apr 30, 2018	May 1, 2018 – Jun 30, 2018	Jul 1, 2018 – Sep 30, 2018	Oct 1, 2018 – Dec 31, 2018	Jan 1, 2019 – Mar 31, 2019	Apr 1, 2019 – Dec 31, 2019	Jan 1, 2020 – Dec 31, 2020	Apr 1, 2018 – Oct 31, 2018	Nov 1, 2018 – Dec 31, 2018
Swaps									
Sold Swaps	$ 55.38	$ 57.20	$ 53.73	$ 53.73	$ 53.73	—	—	—	—
Volume (bbls/d or Mcf/d)	5,000	6,000	3,000	3,000	3,000	—	—	—	—
Three Way Collars									
Sold Puts	$ 42.92	$ 42.92	$ 42.71	$ 42.74	$ 44.05	$ 44.26	$ 46.67	—	—
Volume (bbls/d or Mcf/d)	15,000	15,000	18,000	20,000	16,000	22,000	6,000	—	—
Purchased Puts	$ 52.90	$ 52.90	$ 52.53	$ 52.48	$ 53.69	$ 54.17	$ 56.00	$ 2.75	$ 2.75
Volume (bbls/d or Mcf/d)	15,000	15,000	18,000	20,000	16,000	22,000	6,000	40,000	30,000
Sold Calls	$ 61.73	$ 61.73	$ 61.22	$ 61.10	$ 63.44	$ 64.83	$ 70.33	$ 3.38	$ 3.47
Volume (bbls/d or Mcf/d)	15,000	15,000	18,000	20,000	16,000	22,000	6,000	40,000	30,000

(1) Based on weighted average price (before premiums). A portion of the sold puts are settled annually rather than monthly.

Board of Director Retirement

As previously announced, Mr. David Barr will be retiring from the Board at the Annual Meeting being held later today. Mr. Barr has been a valued member of the Board of Directors since his appointment in 2011. Enerplus would like to acknowledge and thank him for his contribution and dedicated service.

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. In order 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", "should", "believe", "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 average production volumes in 2018 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 funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and estimated differentials and our commodity risk management programs in 2018 and beyond; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash and non-cash G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2018 and its impact on our production level and land holdings; our future royalty and production and cash taxes; future debt and working capital levels and debt to funds flow ratios.

The forward-looking information contained in this news release reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that Enerplus will conduct its operations and achieve results of operations as anticipated; that Enerplus' development plans will achieve the expected results; current commodity price 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 Enerplus' reserves and resources volumes; the continued availability of adequate debt and/or equity financing, cash flow and other sources to fund Enerplus' capital and operating requirements, and dividend payments, as needed; availability of third party services; and the extent of its liabilities. In addition, our 2018 guidance contained in this news release is based on rest of year prices of: WTI US$65.00/bbl, NYMEX US$3.00/Mcf, and a USD/CDN exchange rate of 1.27. 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: changes, including continued volatility, in commodity prices; changes in realized prices for Enerplus' products; changes in the demand for or supply of Enerplus' products; unanticipated operating results, results from Enerplus' capital spending activities or production declines; curtailment of Enerplus' 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 development plans by Enerplus or by third party operators of Enerplus' properties; increased debt levels or debt service requirements; Enerplus' inability to comply with covenants under its bank credit facility and senior notes; changes in estimates of Enerplus' oil and gas reserves and resources 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; failure to complete any anticipated acquisitions or divestitures; and certain other risks detailed from time to time in Enerplus' public disclosure documents (including, without limitation, those risks *identified in its Annual Information Form, management's discussion and analysis for the year-ended December 31, 2017, and Form 40-F at December 31, 2017).*

The forward-looking information contained in this press release speak only as of the date of this press 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" and "net debt to adjusted funds flow ratio" 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. 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" and "net debt to adjusted funds flow" 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 2018 MD&A.

Electronic copies of Enerplus Corporation's First Quarter 2018 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 2, 2018 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, 2018 and 2017 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2017 and 2016 and for the years ended December 31, 2017, 2016 and 2015; and
- our MD&A for the year ended December 31, 2017 (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 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. All production volumes are presented on a Company interest basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests unless otherwise stated. Company interest is not a term defined in Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and may not be comparable to information produced by other entities.

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 2018, Enerplus adopted ASC 606 - *Revenue from contracts with customers*. The adoption of this standard had no impact on the Interim Financial Statements, with the exception of additional note disclosures. See Notes 3(a) and 10 to the Interim Financial Statements for further details.

OVERVIEW

Average daily production for the quarter was 85,080 BOE/day, a decrease of 4% from 88,590 BOE/day in the fourth quarter of 2017. Production decreased in North Dakota as a result of downtime related to completions activities on adjacent properties, along with the expected decrease in volumes with wells coming on-stream toward the end of the quarter. The decrease in crude oil volumes was offset slightly by higher natural gas production in the Marcellus due to improved regional prices. We are well positioned to meet our annual average production guidance ranges of 86,000 – 91,000 BOE/day and our crude oil and natural gas liquids guidance of 46,000 – 50,000 bbls/day, with second quarter crude oil and natural gas liquids production of 48,000 – 50,000 bbls/day.

Capital expenditures of $151.5 million in the first quarter were in line with our expectations. The majority of our capital spending was directed to our crude oil properties, primarily in North Dakota. We are maintaining our 2018 annual capital spending guidance of between $535 and $585 million.

Operating costs for the quarter increased to $53.8 million or $7.02/BOE from $52.1 million or $6.39/BOE in the fourth quarter of 2017. Cash G&A expenses for the first quarter were $13.2 million or $1.72/BOE compared to $12.6 million or $1.55/BOE in the fourth quarter of 2017. The increase in operating costs and cash G&A expenses on a per BOE basis was primarily due to lower production volumes. We are maintaining our annual guidance targets of $7.00/BOE for operating costs and $1.65/BOE for cash G&A expenses.

We continued to add to our commodity hedge positions during the quarter. As of May 2, 2018, we had approximately 67% of our forecasted crude oil production, net of royalties, hedged for the remainder of 2018, and approximately 66% and 19% of our crude oil production, net of royalties, hedged in 2019 and 2020, respectively, based on 2018 forecasted production. We have also hedged approximately 21% of our forecasted natural gas production, net of royalties, for the remainder of 2018.

We recorded net income of $29.6 million and adjusted funds flow of $155.2 million in the first quarter of 2018, compared to $15.3 million and $199.6 million, respectively, in the fourth quarter of 2017. Net income in the fourth quarter was impacted by the remeasurement of our U.S. deferred tax assets as a result of the reduction in the U.S. federal income tax rate in 2017. Both fourth quarter net income and adjusted funds flow benefited from a $50.1 million U.S. Alternative Minimum Tax ("AMT") credit carryover, which we expect to realize in 2018.

At March 31, 2018, our total debt net of cash was $292.0 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 85,080 BOE/day, compared to production of 88,590 BOE/day in the fourth quarter of 2017. Crude oil and liquids production decreased by 5,294 bbls/day, primarily due to lower North Dakota volumes, where we experienced downtime due to completions activities on adjacent properties, along with the expected timing of wells coming on-stream later in the quarter. As a result of improved realized prices, we did not have any production curtailments in the Marcellus during the quarter, which contributed to a 4% increase in natural gas production compared to the fourth quarter of 2017.

Production in the first quarter was consistent with production of 84,937 BOE/day for the same period of the prior year. Our increased capital program in North Dakota resulted in an increase of approximately 9,000 BOE/day of liquids production along with slightly higher Marcellus natural gas production. These increases were offset by the divestment of non-core Canadian properties throughout 2017 and the first quarter of 2018 with associated production of approximately 8,300 BOE/day.

Our crude oil and natural gas liquids weighting increased to 49% in the first quarter of 2018, from 43% for the same period of 2017, due to increased capital spending on our North Dakota crude oil asset and the divestment of non-core natural gas weighted properties.

Average daily production volumes for the three months ended March 31, 2018 and 2017 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2018**	**2017**	**% Change**
Crude oil (bbls/day)	37,443	33,178	13%
Natural gas liquids (bbls/day)	4,085	3,158	29%
Natural gas (Mcf/day)	261,310	291,607	(10%)
Total daily sales (BOE/day)	85,080	84,937	0%

We are well positioned to meet our annual average production guidance ranges of 86,000 – 91,000 BOE/day and our crude oil and natural gas liquids guidance of 46,000 – 50,000 bbls/day, with second quarter crude oil and natural gas liquids production of 48,000 – 50,000 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 average prices for the three months ended March 31, 2018 and 2017 and quarterly average prices for the periods indicated:

Pricing (average for the period)	**Q1 2018**	**Q4 2017**	**Q3 2017**	**Q2 2017**	**Q1 2017**
Benchmarks					
WTI crude oil (US$/bbl)	$ 62.87	$ 55.40	$ 48.20	$ 48.29	$ 51.92
AECO natural gas – monthly index ($/Mcf)	1.85	1.96	2.04	2.77	2.94
AECO natural gas – daily index ($/Mcf)	2.08	1.69	1.45	2.78	2.69
NYMEX natural gas – last day (US$/Mcf)	3.00	2.93	3.00	3.18	3.32
USD/CDN average exchange rate	1.26	1.27	1.25	1.34	1.32
USD/CDN period end exchange rate	1.29	1.26	1.25	1.30	1.33
Enerplus selling price(1)					
Crude oil ($/bbl)	$ 69.67	$ 65.91	$ 54.21	$ 55.66	$ 57.53
Natural gas liquids ($/bbl)	28.13	32.26	26.22	25.14	37.76
Natural gas ($/Mcf)	3.50	3.03	2.58	3.48	3.63
Average differentials					
MSW Edmonton – WTI (US$/bbl)	$ (5.89)	$ (1.14)	$ (2.89)	$ (2.26)	$ (3.54)
WCS Hardisty – WTI (US$/bbl)	(24.28)	(12.27)	(9.94)	(11.13)	(14.58)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.67)	(1.32)	(1.29)	(0.60)	(0.63)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(0.76)	(1.40)	(1.36)	(0.66)	(0.70)
AECO monthly – NYMEX (US$/Mcf)	(1.44)	(1.40)	(1.39)	(1.13)	(1.10)
Enerplus realized differentials(1)(2)					
Canada crude oil – WTI (US$/bbl)	$ (20.82)	$ (10.47)	$ (9.29)	$ (11.02)	$ (12.76)
Canada natural gas – NYMEX (US$/Mcf)	(0.52)	(0.56)	(1.00)	(0.51)	(0.56)
Bakken crude oil – WTI (US$/bbl)	(3.27)	(1.61)	(3.24)	(5.43)	(5.59)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.21)	(0.81)	(1.02)	(0.64)	(0.60)

(1) Excluding transportation costs, royalties and 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 increased by 6% from the fourth quarter of 2017 to average $69.67/bbl. In comparison, benchmark WTI crude oil prices increased by 13% due to lower global crude oil inventories and uncertainty as to when the Organization of the Petroleum Exporting Countries ("OPEC") production agreement will end. This price strength was partially offset by weaker crude oil differentials in both the U.S. and Canada as Canadian crude was restricted due to pipeline egress limitations.

Our realized Bakken price differential to WTI increased by US$1.66/bbl from the fourth quarter of 2017 to average US$3.27/bbl below WTI as stronger WTI prices continue to drive growth in North American crude oil supply. Although this resulted in an increase in differentials for light sweet crude oil in both Canada and the U.S. during the quarter, the overall price received for our Bakken production increased by 11% due to the strength in WTI benchmark prices. As a result of the significant improvement in WTI prices, we are revising our expected 2018 average U.S. Bakken crude oil differential to US$3.50/bbl below WTI based on a WTI price of US$65.00/bbl.

Our realized price differential for our Canadian crude oil production increased by US$10.35/bbl compared to the previous quarter. Canadian crude oil prices deteriorated in the quarter due to pipeline apportionments and continued pipeline flow restrictions following the late 2017 service disruption on the Keystone pipeline. Our realized price for natural gas liquids averaged $28.13/bbl during the period, a decrease of 13% compared to the previous quarter primarily due to weakness in benchmark prices, particularly in propane markets.

NATURAL GAS

Our average realized natural gas price during the first quarter increased by 16% compared to the fourth quarter of 2017 to average $3.50/Mcf, due to a significant improvement in realized prices for our Marcellus production. Comparatively, benchmark NYMEX natural gas prices increased by 2% during the quarter.

Our realized Marcellus sales price differential, excluding transportation and gathering costs, improved considerably from the fourth quarter of 2017 to average US$0.21/Mcf below NYMEX. This outperformed the Benchmark monthly Transco Leidy price which averaged US$0.67/Mcf below NYMEX during the quarter. Our Marcellus portfolio benefitted from the impacts of a colder than normal winter, particularly in early January of 2018, when record cold weather resulted in price spikes in key consumption regions in the U.S. We expect our Marcellus differential to increase during the remainder of 2018 as a portion of our sales portfolio is tied to New York markets that are typically weaker during the summer months. We continue to expect our Marcellus differentials to average US$0.40/Mcf below NYMEX for 2018.

Although benchmark AECO gas prices remained weak due to delivery limitations on export pipelines out of the basin, our realized Canadian natural gas price differential averaged US$0.52/Mcf below NYMEX. We continue to benefit from our multi-year term AECO physical sales contracts, which have an average fixed basis differential of US$0.63/Mcf below NYMEX.

FOREIGN EXCHANGE

The USD/CDN exchange rate was 1.29 USD/CDN at March 31, 2018, and averaged 1.26 USD/CDN during the first quarter of 2018, compared to an exchange rate of 1.26 USD/CDN at December 31, 2017 and an average exchange rate of 1.27 USD/CDN during the fourth quarter of 2017. The majority of our oil and natural gas sales are based on U.S. dollar denominated indices, and a stronger Canadian dollar relative to the U.S. dollar decreases the amount of our realized sales. Because we report in Canadian dollars, the stronger Canadian dollar also decreases our U.S. dollar denominated costs, capital spending and the interest cost on our U.S. dollar denominated debt.

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 2, 2018, we have hedged approximately 21,500 bbls/day of our expected crude oil production for the remainder of 2018, which represents approximately 67% of our forecasted crude oil production, after royalties. For 2019 and 2020, we are hedged on approximately 21,300 bbls/day or 66% and 6,000 bbls/day or 19%, respectively, of our 2018 forecasted crude oil production, after royalties. Our crude oil hedges are predominantly 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 funds flow.

As of May 2, 2018, we have hedged approximately 37,800 Mcf/day of our forecasted natural gas production for the remainder of 2018. This represents approximately 21% of our forecasted natural gas production, after royalties.

The following is a summary of our financial contracts in place at May 2, 2018, expressed as a percentage of our forecasted 2018 net production volumes:

	WTI Crude Oil (US$/bbl)[1]						
	Apr 1, 2018 – Apr 30, 2018	May 1, 2018 – Jun 30, 2018	Jul 1, 2018 – Sep 30, 2018	Oct 1, 2018 – Dec 31, 2018	Jan 1, 2019 – Mar 31, 2019	Apr 1, 2019 – Dec 31, 2019	Jan 1, 2020 – Dec 31, 2020
Swaps							
Sold Swaps	$ 55.38	$ 57.20	$ 53.73	$ 53.73	$ 53.73	—	—
%	16%	19%	9%	9%	9%	—	—
Three Way Collars							
Sold Puts	$ 42.92	$ 42.92	$ 42.71	$ 42.74	$ 44.05	$ 44.26	$ 46.67
%	47%	47%	56%	62%	50%	68%	19%
Purchased Puts	$ 52.90	$ 52.90	$ 52.53	$ 52.48	$ 53.69	$ 54.17	$ 56.00
%	47%	47%	56%	62%	50%	68%	19%
Sold Calls	$ 61.73	$ 61.73	$ 61.22	$ 61.10	$ 63.44	$ 64.83	$ 70.33
%	47%	47%	56%	62%	50%	68%	19%

(1) Based on weighted average price (before premiums) assuming average annual production of 88,500 BOE/day, which is the mid-point of our annual 2018 guidance, less royalties and production taxes of 25%. A portion of the sold puts are settled annually rather than monthly.

	NYMEX Natural Gas (US$/Mcf)[1]	
	Apr 1, 2018 – Oct 31, 2018	Nov 1, 2018 – Dec 31, 2018
Collars		
Purchased Puts	$ 2.75	$ 2.75
%	22%	16%
Sold Calls	$ 3.38	$ 3.47
%	22%	16%

(1) Based on weighted average price (before premiums) assuming average annual production of 88,500 BOE/day, which is the mid-point of our annual 2018 guidance, less royalties and production taxes of 25%.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	Three months ended March 31,	
($ millions)	2018	2017
Cash gains/(losses):		
Crude oil	$ (6.4)	$ (1.0)
Natural gas	16.5	7.6
Total cash gains/(losses)	$ 10.1	$ 6.6
Non-cash gains/(losses):		
Crude oil	$ (29.9)	$ 44.4
Natural gas	(0.7)	6.6
Total non-cash gains/(losses)	$ (30.6)	$ 51.0
Total gains/(losses)	$ (20.5)	$ 57.6

	Three months ended March 31,	
(Per BOE)	2018	2017
Total cash gains/(losses)	$ 1.33	$ 0.86
Total non-cash gains/(losses)	(3.99)	6.67
Total gains/(losses)	$ (2.66)	$ 7.53

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. In comparison, during the first quarter of 2017, we realized cash losses of $1.0 million on our crude oil contracts and cash gains of $7.6 million on our natural gas contracts. Cash losses on crude oil contracts were primarily due to crude oil prices rising above the sold call strike price on our three way collar hedge positions. Cash gains recorded in the quarter on our natural gas contracts included a gain of $15.1 million on the unwind of a portion of our AECO-NYMEX basis physical contracts.

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 2018, the fair value of our crude oil contracts was in a net liability position of $64.1 million, while the fair value of our natural gas contracts was in a net asset position of $1.0 million. For the three months ended March 31, 2018, the change in the fair value of our crude oil contracts and natural gas contracts represented losses of $29.9 million and $0.7 million, respectively.

Revenues

	Three months ended March 31,	
($ millions)	2018	2017
Oil and natural gas sales	$ 328.5	$ 277.7
Royalties	(63.5)	(49.9)
Oil and natural gas sales, net of royalties	$ 265.0	$ 227.8

Oil and natural gas sales, net of royalties for the three months ended March 31, 2018, were $265.0 million an increase of 16% from the same period in 2017. The increase in revenue was a result of the improvement in crude oil prices compared to the prior year, along with a higher crude oil and natural gas liquids weighting of 49% compared to 43%.

Royalties and Production Taxes

	Three months ended March 31,	
($ millions, except per BOE amounts)	2018	2017
Royalties	$ 63.5	$ 49.9
Per BOE	$ 8.30	$ 6.53
Production taxes	$ 16.1	$ 10.4
Per BOE	$ 2.11	$ 1.36
Royalties and production taxes	$ 79.6	$ 60.3
Per BOE	$ 10.41	$ 7.89
Royalties and production taxes (% of oil and natural gas sales)	24%	22%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges. A large percentage of our production is from U.S. properties where royalty rates are generally less sensitive to commodity price levels. During the three months ended March 31, 2018, royalties and production taxes increased to $79.6 million from $60.3 million for the same period in 2017 primarily due to higher crude oil prices and a greater weighting of our production coming from our U.S. properties, which have a combined royalty and production tax rate of approximately 26%. Royalties and production taxes averaged 24% of crude oil and natural gas sales before transportation in the first three months of 2018 compared to 22% for the same period in 2017.

We are maintaining our annual average royalty and production tax rate guidance of 25% for 2018.

Operating Expenses

	Three months ended March 31,	
($ millions, except per BOE amounts)	2018	2017
Cash operating expenses	$ 53.8	$ 50.3
Non-cash (gains)/losses[1]	—	0.1
Total operating expenses	$ 53.8	$ 50.4
Per BOE	$ 7.02	$ 6.59

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

For the three months ended March 31, 2018, operating expenses were $53.8 million or $7.02/BOE compared to our annual guidance of $7.00/BOE. Operating costs increased by $3.4 million compared to the same period in 2017 mainly due to a greater proportion of our production coming from crude oil and natural gas liquids offset by the divestment of higher operating cost Canadian properties throughout 2017 and the first quarter of 2018.

We are maintaining our annual operating cost guidance of $7.00/BOE.

Transportation Costs

	Three months ended March 31,	
($ millions, except per BOE amounts)	2018	2017
Transportation costs	$ 26.9	$ 29.6
Per BOE	$ 3.52	$ 3.88

For the three months ended March 31, 2018, transportation costs were $26.9 million or $3.52/BOE compared to our annual guidance of $3.60/BOE. During the same period in 2017 transportation costs were $29.6 million or $3.88/BOE. The decrease is primarily due to the divestment of non-core Canadian natural gas properties in 2017 and a stronger Canadian dollar during the first quarter of 2018, which lowered the cost of our U.S. transportation expenses.

We are maintaining our annual guidance for transportation costs of $3.60/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, 2018		
Netbacks by Property Type	**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 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

	Three months ended March 31, 2017		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	40,393 BOE/day	267,264 Mcfe/day	84,937 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 49.14	$ 4.12	$ 36.33
Royalties and production taxes	(12.58)	(0.60)	(7.89)
Cash operating expenses	(10.26)	(0.54)	(6.57)
Transportation costs	(2.50)	(0.85)	(3.88)
Netback before hedging	$ 23.80	$ 2.13	$ 17.99
Cash gains/(losses)	(0.26)	0.31	0.86
Netback after hedging	$ 23.54	$ 2.44	$ 18.85
Netback before hedging ($ millions)	$ 86.4	$ 51.1	$ 137.5
Netback after hedging ($ millions)	$ 85.5	$ 58.6	$ 144.1

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

Crude oil netbacks per BOE before hedging were higher for the three months ended March 31, 2018, compared to the same period in 2017 primarily due to higher crude oil sales and improved realized prices. Natural gas netbacks before hedging were lower for the first quarter of 2018 compared to the same period in 2017 mainly due to lower production with the divestment of non-core Canadian natural gas properties and weaker realized prices. For the three months ended March 31, 2018, our crude oil properties accounted for 79% of our netback before hedging, compared to 63% during the same period in 2017.

General and Administrative ("G&A") Expenses

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

	Three months ended March 31,	
($ millions)	**2018**	**2017**
Cash:		
G&A expense	$ 13.2	$ 14.3
Share-based compensation expense	1.9	0.2
Non-Cash:		
Share-based compensation expense	9.1	8.1
Equity swap loss/(gain)	(1.0)	0.9
Total G&A expenses	$ 23.2	$ 23.5

(Per BOE)	Three months ended March 31, 2018	2017
Cash:		
G&A expense	$ 1.72	$ 1.87
Share-based compensation expense	0.25	0.02
Non-Cash:		
Share-based compensation expense	1.19	1.06
Equity swap loss/(gain)	(0.13)	0.12
Total G&A expenses	$ 3.03	$ 3.07

For the three months ended March 31, 2018, cash G&A expenses were $13.2 million or $1.72/BOE compared to $14.3 million or $1.87/BOE for the same period in 2017. The decrease in cash G&A expenses from the prior year was primarily due to the impact of reductions in staff levels throughout 2017 as we continued to focus our business through asset divestments.

During the quarter, we reported cash SBC expense of $1.9 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 2017, we recorded cash SBC expense of $0.2 million. We recorded non-cash SBC of $9.1 million or $1.19/BOE in the first quarter of 2018, which was in line with $8.1 million or $1.06/BOE during the same period in 2017.

We have hedges in place on the outstanding cash-settled grants under our LTI plans. In the first quarter we recorded a non-cash mark-to-market gain of $1.0 million on these hedges due to the increase in our share price. As of March 31, 2018, we had 470,000 units hedged at a weighted average price of $16.89 per share.

We are maintaining our annual cash G&A guidance of $1.65/BOE.

Interest Expense

For the three months ended March 31, 2018, we recorded total interest expense of $9.1 million compared to $10.1 million for the same period in 2017. The decrease in interest expense for the three month period was primarily due to the impact of a strengthening Canadian dollar on our U.S. dollar denominated interest expense, along with the payment of our first installment of US$22 million on our US$110 million senior notes, which carry a higher coupon rate, during the second quarter of 2017.

At March 31, 2018, we were undrawn on our $800 million bank credit facility and our debt balance consisted entirely of fixed interest rate senior notes with a weighted average interest rate of 4.8%. See Note 8 to the Interim Financial Statements for further details.

Foreign Exchange

($ millions)	Three months ended March 31, 2018	2017
Realized:		
Foreign exchange (gain)/loss on settlements	$ 0.1	$ 0.1
Translation of U.S. dollar cash held in Canada (gain)/loss	(7.3)	—
Unrealized (gain)/loss	17.6	(3.9)
Total foreign exchange (gain)/loss	$ 10.4	$ (3.8)
USD/CDN average exchange rate	1.26	1.32
USD/CDN period end exchange rate	1.29	1.33

For the three months ended March 31, 2018, we recorded a net foreign exchange loss of $10.4 million compared to a gain of $3.8 million for the same period in 2017. Realized gains and losses include day-to-day transactions recorded in foreign currencies, and the translation of our U.S. dollar denominated cash held in Canada, while unrealized gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period end. Comparing the period end exchange rate at March 31, 2018 to December 31, 2017, the Canadian dollar weakened relative to the U.S. dollar, resulting in an unrealized loss of $17.6 million. See Note 12 to the Interim Financial Statements for further details.

Capital Investment

($ millions)	Three months ended March 31, 2018	2017
Capital spending	$ 151.5	$ 120.4
Office capital	1.4	0.1
Sub-total	152.9	120.5
Property and land acquisitions	$ 12.3	$ 2.5
Property divestments	(7.0)	0.9
Sub-total	5.3	3.4
Total (1)	$ 158.2	$ 123.9

(1) Excludes changes in non-cash investing working capital. See Note 17(b) to the Interim Financial Statements for further details.

Capital spending for the three months ended March 31, 2018, totaled $151.5 million compared to the $120.4 million for the same period in 2017. The increase in spending is in line with our strategy to deliver production and liquids growth through 2018. During the quarter we spent $121.5 million on our U.S. crude oil properties, $16.8 million on our Marcellus natural gas assets and $12.1 million on our Canadian waterflood properties.

In the first quarter, we completed $12.3 million in property and land acquisitions which included minor acquisitions of leases and undeveloped land. During the first quarter, property divestments totaled $7.0 million primarily related to an acreage swap in North Dakota and the divestment of non-core properties in N.W. Alberta with associated production of approximately 600 BOE/day.

We continue to expect annual capital spending of $535 to $585 million.

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

($ millions, except per BOE amounts)	Three months ended March 31, 2018	2017
DD&A expense	$ 64.0	$ 60.6
Per BOE	$ 8.36	$ 7.92

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, 2018, DD&A increased compared to the same period of 2017 as a result of an increased weighting of U.S. production with higher depletion rates.

Asset Retirement Obligation

In connection with our operations, we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are based on our net ownership interest and management's estimate of costs to abandon and reclaim such assets and the timing of the cost to be incurred in future periods. We have estimated the net present value of our asset retirement obligation to be $118.6 million at March 31, 2018, compared to $117.7 million at December 31, 2017. For the three months ended March 31, 2018, asset retirement obligation settlements were $3.3 million compared to $2.5 million during the same period in 2017. As a result of our divestments in the first quarter of 2018, we have reduced our asset retirement obligation by $3.7 million. See Note 9 to the Interim Financial Statements for further details.

Income Taxes

($ millions)	Three months ended March 31, 2018	2017
Current tax expense/(recovery)	$ 0.1	$ 0.1
Deferred tax expenses/(recovery)	12.4	28.8
Total tax expense/(recovery)	$ 12.5	$ 28.9

We recorded a total tax expense of $12.5 million during the first quarter of 2018 compared to $28.9 million for the same period in 2017. The decrease in the total tax expense is due to lower overall income in 2018, as well as a reduction to the U.S. federal income tax rate to 21% from 35% effective January 1, 2018 with the enactment of the U.S. Tax Cuts and Jobs Act. See Note 13 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 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, 2018, our senior debt to adjusted EBITDA ratio was 1.2x 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, 2018 was $292.0 million, a decrease of 10% compared to $325.8 million at December 31, 2017. Total debt was comprised of $688.4 million of senior notes less $396.4 million in cash. At March 31, 2018, we were undrawn on our $800 million bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by adjusted funds flow, was 103% for the three months ended March 31, 2018, compared to 107% for the same period in 2017.

Our working capital deficiency, excluding cash and current deferred financial assets and liabilities, increased to $162.6 million at March 31, 2018 from $107.6 million at December 31, 2017. 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, 2018, 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, 2018:

Covenant Description		March 31, 2018
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	1.2x
Total debt to adjusted EBITDA (1)	4.0x	1.2x
Total debt to capitalization	50%	21%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	1.2x
Senior debt to consolidated present value of total proved reserves(3)	60%	26%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	16.4x

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, 2018 was $171.7 million and $619.5 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 for the senior notes, 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)	2018	2017
Dividends to shareholders	$ 7.3	$ 7.2
Per weighted average share (Basic)	$ 0.03	$ 0.03

During the three months ended March 31, 2018, we reported total dividends of $7.3 million or $0.03 per share compared to $7.2 million or $0.03 per share for the same period in 2017.

The dividend is part of our strategy to create shareholder value. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	Three months ended March 31,	
	2018	2017
Share capital ($ millions)	$ 3,411.9	$ 3,386.9
Common shares outstanding (thousands)	244,773	242,129
Weighted average shares outstanding – basic (thousands)	243,874	241,285
Weighted average shares outstanding – diluted (thousands)	249,191	246,358

During the first quarter, a total of 2,644,000 shares were issued pursuant to our stock option plan and treasury-settled LTI plans and $23.5 million was transferred from paid-in capital to share capital (2017 – 1,646,000; $21.0 million). For further details, see Note 14 to the Interim Financial Statements.

On March 21, 2018, Enerplus announced the acceptance of its Normal Course Issuer Bid ("the bid") by the Toronto Stock Exchange ("TSX"). The bid allows Enerplus to purchase up to 17,095,598 common shares on the TSX, the New York Stock Exchange and/or alternative Canadian trading systems over a period of twelve months commencing on March 26, 2018. All common shares purchased under the bid will be cancelled. For the period ended March 31, 2018, no common shares were purchased.

At May 2, 2018, we had 244,823,365 common shares outstanding. In addition, an aggregate of 11,866,379 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.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended March 31, 2018			Three months ended March 31, 2017		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	9,513	27,930	37,443	12,907	20,271	33,178
Natural gas liquids (bbls/day)	1,247	2,838	4,085	1,405	1,753	3,158
Natural gas (Mcf/day)	33,132	228,178	261,310	68,542	223,065	291,607
Total average daily production (BOE/day)	16,282	68,798	85,080	25,736	59,201	84,937
Pricing(2)						
Crude oil (per bbl)	$ 52.82	$ 75.41	$ 69.67	$ 51.67	$ 61.26	$ 57.53
Natural gas liquids (per bbl)	45.11	20.66	28.13	37.09	38.30	37.76
Natural gas (per Mcf)	3.12	3.56	3.50	3.65	3.62	3.63
Capital Expenditures						
Capital spending	$ 13.2	$ 138.3	$ 151.5	$ 25.0	$ 95.4	$ 120.4
Acquisitions	1.1	11.2	12.3	1.5	1.0	2.5
Divestments	(0.9)	(6.1)	(7.0)	0.9	—	0.9
Netback(3) **Before Hedging**						
Oil and natural gas sales	$ 60.7	$ 267.8	$ 328.5	$ 87.2	$ 190.5	$ 277.7
Royalties	(9.9)	(53.6)	(63.5)	(11.9)	(38.0)	(49.9)
Production taxes	(0.8)	(15.3)	(16.1)	(1.1)	(9.3)	(10.4)
Cash operating expenses	(20.6)	(33.2)	(53.8)	(26.6)	(23.7)	(50.3)
Transportation costs	(3.0)	(23.9)	(26.9)	(4.4)	(25.2)	(29.6)
Netback before hedging	$ 26.4	$ 141.8	$ 168.2	$ 43.2	$ 94.3	$ 137.5
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 20.5	$ —	$ 20.5	$ (57.6)	$ —	$ (57.6)
General and administrative expense(4)	15.4	7.8	23.2	17.8	5.7	23.5
Current income tax expense/(recovery)	—	0.1	0.1	—	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.

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
2018				
First Quarter	$ 265.0	$ 29.6	$ 0.12	$ 0.12
Total 2018	$ 265.0	$ 29.6	$ 0.12	$ 0.12
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
2016				
Fourth Quarter	$ 217.4	$ 840.3	$ 3.49	$ 3.43
Third Quarter	188.3	(100.7)	(0.42)	(0.42)
Second Quarter	174.3	(168.5)	(0.77)	(0.77)
First Quarter	142.7	(173.7)	(0.84)	(0.84)
Total 2016	$ 722.7	$ 397.4	$ 1.75	$ 1.72

Oil and natural gas sales, net of royalties, decreased slightly in the first quarter of 2018 compared to the fourth quarter of 2017 due to decreased production volumes offset by higher realized prices. Net income increased in the first quarter of 2018 due to the higher deferred income tax expense recorded in the fourth quarter of 2017 as a result of re-measurement of our U.S. deferred tax assets for the U.S. federal income tax rate reduction. Oil and natural gas sales, net of royalties, increased in 2017 compared to 2016 due to an increase in realized commodity prices, offset by a decrease in production due to non-core asset divestments. Net income for 2017 decreased from 2016, due to lower gains recorded on asset divestments, along with an increase in deferred tax expense. Net income was higher in the second quarter of 2017 due to a $78.4 million gain recorded on the divestment of certain Canadian assets.

2018 UPDATED GUIDANCE

Our 2018 guidance is summarized below. We have included second quarter 2018 crude oil and natural gas liquids production guidance of 48,000 – 50,000 bbls/day and revised our 2018 average U.S. Bakken crude oil differential to US$3.50/bbl below WTI.

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

Summary of 2018 Expectations	Target
Capital spending	$535 – $585 million
Average second quarter crude oil and natural gas liquids production	48,000 - 50,000 bbls/day
Average annual production	86,000 – 91,000 BOE/day
Average annual crude oil and natural gas liquids production	46,000 – 50,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	25%
Operating expenses	$7.00/BOE
Transportation costs	$3.60/BOE
Cash G&A expenses	$1.65/BOE

2018 Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.50)/bbl (from US$(2.50)/bbl)
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.40)/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)	2018	2017
Oil and natural gas sales	$ 328.5	$ 277.7
Less:		
Royalties	(63.5)	(49.9)
Production taxes	(16.1)	(10.4)
Cash operating expenses(1)	(53.8)	(50.3)
Transportation costs	(26.9)	(29.6)
Netback before hedging	$ 168.2	$ 137.5
Cash gains/(losses) on derivative instruments	10.1	6.6
Netback after hedging	$ 178.3	$ 144.1

(1) Total operating expenses have been adjusted to exclude a non-cash loss of $0.1 million for the three months ended March 31, 2017 (Three months ended March 31, 2018 – nil).

"Adjusted funds flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating 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)	2018	2017
Cash flow from operating activities	$ 159.3	$ 127.9
Asset retirement obligation expenditures	3.3	2.5
Changes in non-cash operating working capital	(7.4)	(10.5)
Adjusted funds flow	$ 155.2	$ 119.9

"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 restricted cash.

"**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 and office expenditures divided by adjusted funds flow.

Calculation of Adjusted Payout Ratio	Three months ended March 31,	
($ millions)	2018	2017
Dividends	$ 7.3	$ 7.2
Capital and office expenditures	152.9	120.5
Sub-total	$ 160.2	$ 127.7
Adjusted funds flow	$ 155.2	$ 119.9
Adjusted payout ratio (%)	103%	107%

"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, 2018
Net income/(loss)	$ 190.3
Add:	
Interest	37.7
Current and deferred tax expense/(recovery)	65.7
DD&A and asset impairment	254.2
Other non-cash charges(2)	75.9
Sub-total	$ 623.8
Adjustment for material acquisitions and divestments(3)	(4.3)
Adjusted EBITDA	$ 619.5

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at March 31, 2018 include the three months ended March 31, 2018 and the second, third and fourth quarter of 2017.
(2) Includes the change in fair value of commodity derivatives, fixed price electricity swaps and equity swaps, non-cash SBC, and unrealized foreign exchange gains/losses.
(3) EBITDA is adjusted for material acquisitions or divestments during the period with net proceeds greater than $50 million as if that acquisition or disposition had been made at the beginning of the period.

In addition, the Company uses certain financial measures within the “Overview” and “Liquidity and Capital Resources” sections of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include “senior debt to adjusted EBITDA”, “total debt to adjusted EBITDA”, “total debt to capitalization”, “maximum 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, 2018, 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, 2018 and ended March 31, 2018 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 2018 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our adjusted funds flow; anticipated production volumes subject to curtailment; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity risk management program in 2018 and in the future; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2018 and impact thereof on our production levels; 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 and to negotiate relief if required; 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; our ability to negotiate debt covenant relief under our bank credit facility and outstanding senior notes if required; the availability of third party services; and the extent of our liabilities. In addition, our updated 2018 guidance contained in this MD&A is based on the following prices for the first quarter: a WTI price of US$65.00/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.00/GJ and a USD/CDN exchange rate of 1.27. 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, 2017).*

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, 2018	December 31, 2017
Assets			
Current Assets			
Cash and cash equivalents		$ 396,395	$ 346,548
Accounts receivable	4	135,988	130,576
Deferred financial assets	15	2,561	3,852
Other current assets		4,282	5,902
		539,226	486,878
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	5	1,005,222	889,967
Other capital assets, net	5	10,673	10,064
Property, plant and equipment		1,015,895	900,031
Goodwill		643,553	638,878
Deferred income tax asset	13	566,317	569,937
Income tax receivable	13	51,356	50,108
Total Assets		$ 2,816,347	$ 2,645,832
Liabilities			
Current liabilities			
Accounts payable	7	$ 272,039	$ 213,978
Dividends payable		2,448	2,421
Current portion of long-term debt	8	28,345	27,656
Deferred financial liabilities	15	50,153	28,642
		352,985	272,697
Deferred financial liabilities	15	16,727	9,907
Long-term debt	8	660,028	644,723
Asset retirement obligation	9	118,645	117,736
		795,400	772,366
Total Liabilities		1,148,385	1,045,063
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: March 31, 2018 – 245 million shares			
December 31, 2017 – 242 million shares	14	3,411,878	3,386,946
Paid-in capital		60,951	75,375
Accumulated deficit		(2,102,359)	(2,124,676)
Accumulated other comprehensive income/(loss)		297,492	263,124
		1,667,962	1,600,769
Total Liabilities & Shareholders' Equity		$ 2,816,347	$ 2,645,832
Contingencies	16		

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, 2018	2017
Revenues			
Oil and natural gas sales, net of royalties	10	$ 265,020	$ 227,816
Commodity derivative instruments gain/(loss)	15	(20,464)	57,562
		244,556	285,378
Expenses			
Operating		53,761	50,381
Transportation		26,921	29,628
Production taxes		16,135	10,364
General and administrative	11	23,224	23,493
Depletion, depreciation and accretion		64,046	60,580
Interest		9,103	10,141
Foreign exchange (gain)/loss	12	10,371	(3,858)
Other expense/(income)		(1,183)	(485)
		202,378	180,244
Income/(Loss) before taxes		42,178	105,134
Current income tax expense/(recovery)	13	66	74
Deferred income tax expense/(recovery)	13	12,475	28,767
Net Income/(Loss)		$ 29,637	$ 76,293
Other Comprehensive Income/(Loss)			
Change in cumulative translation adjustment		34,368	(10,302)
Total Comprehensive Income/(Loss)		$ 64,005	$ 65,991
Net income/(Loss) per share			
Basic	14	$ 0.12	$ 0.32
Diluted	14	$ 0.12	$ 0.31

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, 2018	2017
Share Capital		
Balance, beginning of year	$ 3,386,946	$ 3,365,962
Share-based compensation – settled	23,389	20,984
Stock Option Plan - cash	1,429	—
Stock Option Plan - exercised	114	—
Balance, end of period	$ 3,411,878	$ 3,386,946
Paid-in Capital		
Balance, beginning of year	$ 75,375	$ 73,783
Share-based compensation – settled	(23,389)	(20,984)
Share-based compensation – non-cash	9,079	8,120
Stock Option Plan - exercised	(114)	—
Balance, end of period	$ 60,951	$ 60,919
Accumulated Deficit		
Balance, beginning of year	$ (2,124,676)	$ (2,332,641)
Net income/(loss)	29,637	76,293
Dividends declared	(7,320)	(7,242)
Balance, end of period	$ (2,102,359)	$ (2,263,590)
Accumulated Other Comprehensive Income/(Loss)		
Balance, beginning of year	$ 263,124	$ 353,401
Change in cumulative translation adjustment	34,368	(10,302)
Balance, end of period	$ 297,492	$ 343,099
Total Shareholders' Equity	$ 1,667,962	$ 1,527,374

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, 2018	2017
Operating Activities			
Net income/(loss)		$ 29,637	$ 76,293
Non-cash items add/(deduct):			
Depletion, depreciation and accretion		64,046	60,580
Changes in fair value of derivative instruments	15	29,622	(49,929)
Deferred income tax expense/(recovery)	13	12,475	28,767
Foreign exchange (gain)/loss on debt and working capital	12	17,649	(3,911)
Share-based compensation	14	9,079	8,120
Translation of U.S. dollar cash held in Canada	12	(7,346)	—
Asset retirement obligation expenditures	9	(3,331)	(2,541)
Changes in non-cash operating working capital	17	7,469	10,544
Cash flow from/(used in) operating activities		159,300	127,923
Financing Activities			
Dividends	17	(7,294)	(7,226)
Bank credit facility		—	(19,229)
Proceeds from the issuance of shares	14	1,429	—
Cash flow from/(used in) financing activities		(5,865)	(26,455)
Investing Activities			
Capital and office expenditures	17	(108,212)	(94,171)
Property and land acquisitions		(6,190)	(2,536)
Property divestments		888	(899)
Cash flow from/(used in) investing activities		(113,514)	(97,606)
Effect of exchange rate changes on cash and cash equivalents		9,926	(3,569)
Change in cash and cash equivalents		49,847	293
Cash and cash equivalents, beginning of period		346,548	393,305
Cash and cash equivalents, end of period		$ 396,395	$ 393,598

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, 2018 and the 2017 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, 2017. 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, 2017.

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 606 *Revenue from contracts with customers* effective January 1, 2018 as detailed below. Enerplus used the modified retrospective method to adopt the new standard, with ASC 606 applied to all contracts not yet completed as of the date of adoption and the cumulative effect on comparative periods reflected as an adjustment to opening retained earnings. The adoption of the new standard had no impact on the interim Consolidated Financial Statements, with the exception of the additional disclosures which are detailed in Note 10.

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

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

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 February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842).* The ASU introduced a lessee accounting model that requires lessees to recognize a right-of-use asset and related lease liability on the balance sheet for all leases, including operating leases. The standard does not apply to oil and gas exploration rights, intangible assets or inventory. The new standard also expands disclosures related to the amount, timing and uncertainty of cash flows arising from leases. The standard will be applied using a modified retrospective approach and provides for certain practical expedients at the date of adoption. The ASU is effective January 1, 2019. Enerplus does not expect to early adopt the standard. The Company is currently reviewing existing contracts to determine the impact to the Consolidated Financial Statements of adopting the new standard. The Company is also addressing system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new standard.

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.

In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815),* making more hedging strategies eligible for hedge accounting. The new guidance is effective January 1, 2019, and will be applied prospectively. Hedge accounting continues to be an elective accounting policy choice. Enerplus does not currently apply hedge accounting. Enerplus is currently assessing the impact ASU 2017-12 would have on the Consolidated Financial Statements should it elect to apply hedge accounting.

4) ACCOUNTS RECEIVABLE

($ thousands)	March 31, 2018	December 31, 2017
Accrued revenue	$ 112,407	$ 102,051
Accounts receivable – trade	25,846	30,787
Current income tax receivable	1,210	1,190
Allowance for doubtful accounts	(3,475)	(3,452)
Total accounts receivable, net of allowance for doubtful accounts	$ 135,988	$ 130,576

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

As of March 31, 2018 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties	$ 13,929,294	$ (12,924,072)	$ 1,005,222
Other capital assets	109,401	(98,728)	10,673
Total PP&E	$ 14,038,695	$ (13,022,800)	$ 1,015,895

As of December 31, 2017 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties	$ 13,622,266	$ (12,732,299)	$ 889,967
Other capital assets	107,582	(97,518)	10,064
Total PP&E	$ 13,729,848	$ (12,829,817)	$ 900,031

6) ASSET IMPAIRMENT

There was no impairment recorded for the three months ended March 31, 2018 and 2017.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from March 31, 2017 through March 31, 2018:

Period	WTI Crude Oil US$/bbl	Exchange Rate US$/CDN$	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	AECO Natural Gas Spot CDN$/Mcf
Q1 2018	$ 53.49	1.28	$ 64.57	$ 3.00	$ 2.17
Q4 2017	51.34	1.30	63.57	2.98	2.32
Q3 2017	49.81	1.32	61.63	3.05	2.66
Q2 2017	48.95	1.33	60.79	3.05	2.79
Q1 2017	47.61	1.31	58.02	2.77	2.41

7) ACCOUNTS PAYABLE

($ thousands)	March 31, 2018	December 31, 2017
Accrued payables	$ 141,569	$ 96,743
Accounts payable - trade	130,470	117,235
Total accounts payable	$ 272,039	$ 213,978

8) DEBT

($ thousands)	March 31, 2018	December 31, 2017
Current:		
Senior notes	$ 28,345	$ 27,656
Long-term:		
Bank credit facility	$ —	$ —
Senior notes	660,028	644,723
Total debt	$ 688,373	$ 672,379

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	$ 135,283
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	25,768
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$298,000	383,943
June 18, 2009	June 18 and Dec 18	4 equal annual installments June 18, 2018 - 2021	7.97%	US$225,000	US$88,000	113,379
					Total carrying value	$ 688,373

9) ASSET RETIREMENT OBLIGATION

($ thousands)	Three months ended March 31, 2018	Year ended December 31, 2017
Balance, beginning of year	$ 117,736	$ 181,700
Change in estimates	6,158	13,064
Property acquisitions and development activity	325	1,322
Dispositions	(3,718)	(72,306)
Settlements	(3,331)	(12,907)
Accretion expense	1,475	6,863
Balance, end of period	$ 118,645	$ 117,736

Enerplus has estimated the present value of its asset retirement obligation to be $118.6 million at March 31, 2018 based on a total undiscounted liability of $318.7 million (December 31, 2017 – $117.7 million and $318.8 million, respectively). The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.70% (December 31, 2017 – 5.73%).

10) OIL AND NATURAL GAS SALES

	Three months ended March 31,	
($ thousands)	2018	2017
Oil and natural gas sales	$ 328,552	$ 277,745
Royalties[(1)]	(63,532)	(49,929)
Oil and natural gas sales, net of royalties	$ 265,020	$ 227,816

(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, 2018 are as follows:

($ 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 our North Dakota and Marcellus properties, respectively. Canadian crude oil sales relate primarily to our waterflood properties.
(3) Includes third party processing income.

Enerplus sells the majority of its production pursuant to variable-price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver a fixed or variable volume of crude oil, natural gas liquids or natural gas to the contract counterparty. Revenue is recognized when a unit of production is delivered to the contract counterparty. The amount of revenue recognized is based on the agreed transaction price, and any variability in revenue relates to the Company's ability to deliver product. As a result, revenue is allocated to the production delivered in the period.

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

11) GENERAL AND ADMINISTRATIVE EXPENSE

	Three months ended March 31,	
($ thousands)	2018	2017
General and administrative expense	$ 13,205	$ 14,271
Share-based compensation expense[(1)]	10,019	9,222
General and administrative expense	$ 23,224	$ 23,493

(1) Includes cash and non-cash share-based compensation.

12) FOREIGN EXCHANGE

	Three months ended March 31,	
($ thousands)	2018	2017
Realized:		
Foreign exchange (gain)/loss	$ 68	$ 53
Translation of U.S. dollar cash held in Canada (gain)/loss	(7,346)	—
Unrealized:		
Translation of U.S. dollar debt and working capital (gain)/loss	17,649	(3,911)
Foreign exchange (gain)/loss	$ 10,371	$ (3,858)

13) INCOME TAXES

($ thousands)	Three months ended March 31, 2018	2017
Current tax expense/(recovery)		
United States	$ 66	$ 74
Deferred tax expense/(recovery)		
Canada	$ (5,510)	$ 13,619
United States	17,985	15,148
	12,475	28,767
Income tax expense/(recovery)	$ 12,541	$ 28,841

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 non-deductible share-based compensation. Our overall net deferred income tax asset was $566.3 million at March 31, 2018 (December 31, 2017 - $569.9 million).

At March 31, 2018, the Company had a $51.4 million income tax receivable related to the portion of the U.S. Alternative Minimum Tax ("AMT") refund expected to be realized in 2018 (December 31, 2017 - $50.1 million).

14) SHAREHOLDERS' EQUITY

a) Share Capital

	Three months ended March 31, 2018		Year ended December 31, 2017	
Authorized unlimited number of common shares issued: (thousands)	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	242,129	$ 3,386,946	240,483	$ 3,365,962
Issued for cash:				
Stock Option Plan	105	1,429	—	—
Non-cash:				
Share-based compensation – settled	2,539	23,389	1,646	20,984
Stock Option Plan - exercised	—	114	—	—
Balance, end of period	244,773	$ 3,411,878	242,129	$ 3,386,946

Dividends declared to shareholders for the three months ended March 31, 2018 was $7.3 million (2017 - $7.2 million).

b) Share-based Compensation

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

($ thousands)	Three months ended March 31, 2018	2017
Cash:		
Long-term incentive plans expense	$ 1,946	$ 155
Non-cash:		
Long-term incentive plans	9,079	8,120
Equity swap (gain)/loss	(1,006)	947
Share-based compensation expense	$ 10,019	$ 9,222

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, 2018:

For the three months ended March 31, 2018	**Cash-settled LTI plans**	**Equity-settled LTI plans**		**Total**
(thousands of units)	**DSU**	**PSU**	**RSU**	
Balance, beginning of year	368	2,713	2,109	5,190
Granted	76	1,449	790	2,315
Vested	—	(1,459)	(1,080)	(2,539)
Forfeited	—	—	(25)	(25)
Balance, end of period	444	2,703	1,794	4,941

Cash-settled LTI Plans

For the three months ended March 31, 2018, the Company recorded cash share-based compensation expense of $1.9 million (March 31, 2017 - $0.2 million). For the three months ended March 31, 2018, the Company made cash payments of nil related to its cash-settled plans (March 31, 2017 – $0.1 million).

As of March 31, 2018, a liability of $6.4 million (December 31, 2017 - $4.5 million) with respect to the DSU plan has been recorded to Accounts Payable on the Consolidated Balance Sheets.

Equity-settled LTI Plans

For the three months ended March 31, 2018, the Company recorded non-cash share-based compensation expense of $9.1 million (2017 – $8.1 million).

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

At March 31, 2018 ($ thousands, except for years)	**PSU[(1)]**	**RSU**	**Total**
Cumulative recognized share-based compensation expense	$ 19,446	$ 6,620	$ 26,066
Unrecognized share-based compensation expense	13,896	9,984	23,880
Fair value	$ 33,342	$ 16,604	$ 49,946
Weighted-average remaining contractual term (years)	1.9	1.7	

(1) Includes estimated performance multipliers.

ii) Stock Option Plan

The Company suspended the issuance of stock options in 2014. At March 31, 2018, 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, 2018:

Period ended March 31, 2018	**Number of Options** (thousands)	**Weighted Average Exercise Price**
Options outstanding, beginning of year	5,486	$ 18.25
Exercised	(105)	13.66
Forfeited	(19)	22.71
Expired	(638)	30.20
Options outstanding, end of period	4,724	$ 16.72
Options exercisable, end of period	4,724	$ 16.72

At March 31, 2018, Enerplus had 4,723,746 options that were exercisable at a weighted average exercise price of $16.72 with a weighted average remaining contractual term of 1.5 years, giving an aggregate intrinsic value of $2.2 million (2017 – 2.3 years and nil). The intrinsic value of options exercised for the three months ended March 31, 2018 was $0.2 million (March 31, 2017 – nil).

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

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

(thousands, except per share amounts)	Three months ended March 31, 2018	2017
Net income/(loss)	$ 29,637	$ 76,293
Weighted average shares outstanding – Basic	243,874	241,285
Dilutive impact of share-based compensation	5,317	5,073
Weighted average shares outstanding – Diluted	249,191	246,358
Net income/(loss) per share		
Basic	$ 0.12	$ 0.32
Diluted	$ 0.12	$ 0.31

15) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At March 31, 2018, 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, 2018, senior notes had a carrying value of $688.4 million and a fair value of $697.1 million (December 31, 2017 - $672.4 million and $687.2 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 deferred financial assets and liabilities on the 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, 2018 and 2017:

Gain/(Loss) ($ thousands)	Three months ended March 31, 2018	2017	Income Statement Presentation
Electricity Swaps	$ (16)	$ (117)	Operating expense
Equity Swaps	1,006	(947)	G&A expense
Commodity Derivative Instruments:			
Oil	(29,855)	44,358	Commodity derivative instruments
Gas	(757)	6,635	
Total	$ (29,622)	$ 49,929	

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

($ thousands)	Three months ended March 31, 2018	2017
Change in fair value gain/(loss)	$ (30,612)	$ 50,993
Net realized cash gain/(loss)	10,148	6,569
Commodity derivative instruments gain/(loss)	$ (20,464)	$ 57,562

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

	March 31, 2018			December 31, 2017		
	Assets	Liabilities		Assets	Liabilities	
($ thousands)	Current	Current	Long-term	Current	Current	Long-term
Electricity Swaps	$ —	$ 16	$ —	$ —	$ —	$ —
Equity Swaps	—	1,113	—	—	2,119	—
Commodity Derivative Instruments:						
Oil	1,608	49,024	16,727	2,142	26,523	9,907
Gas	953	—	—	1,710	—	—
Total	$ 2,561	$ 50,153	$ 16,727	$ 3,852	$ 28,642	$ 9,907

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 2, 2018:

Crude Oil Instruments:

Instrument Type[(1)]	bbls/day	US$/bbl
Apr 1, 2018 – Apr 30, 2018		
WTI Swap	5,000	55.38
WTI Purchased Put	15,000	52.90
WTI Sold Call	15,000	61.73
WTI Sold Put	15,000	42.92
WCS Differential Swap (Sale)	1,500	(14.75)
WCS Differential Swap (Purchase)	1,500	(25.50)
May 1, 2018 – May 31, 2018		
WTI Swap	6,000	57.20
WTI Purchased Put	15,000	52.90
WTI Sold Call	15,000	61.73
WTI Sold Put	15,000	42.92
WCS Differential Swap (Sale)	3,000	(14.46)
Jun 1, 2018 – Jun 30, 2018		
WTI Swap	6,000	57.20
WTI Purchased Put	15,000	52.90
WTI Sold Call	15,000	61.73
WTI Sold Put	15,000	42.92
WCS Differential Swap (Sale)	4,000	(14.62)
Jul 1, 2018 – Sep 30, 2018		
WTI Swap	3,000	53.73
WTI Purchased Put	18,000	52.53
WTI Sold Call	18,000	61.22
WTI Sold Put	18,000	42.71
WCS Differential Swap (Sale)	3,000	(14.46)
Oct 1, 2018 – Dec 31, 2018		
WTI Swap	3,000	53.73
WTI Purchased Put	20,000	52.48
WTI Sold Call	20,000	61.10
WTI Sold Put	20,000	42.74
WCS Differential Swap (Sale)	3,000	(14.46)

Jan 1, 2019 – Mar 31, 2019		
WTI Swap	3,000	53.73
WTI Purchased Put	16,000	53.69
WTI Sold Call	16,000	63.44
WTI Sold Put	16,000	44.05
WCS Differential Swap (Sale)	1,500	(14.17)
Apr 1, 2019 – Jun 30, 2019		
WTI Purchased Put	22,000	54.17
WTI Sold Call	22,000	64.85
WTI Sold Put	22,000	44.26
Jul 1, 2019 – Sep 30, 2019		
WTI Purchased Put	22,000	54.17
WTI Sold Call	22,000	64.80
WTI Sold Put	22,000	44.26
Oct 1, 2019 – Dec 31, 2019		
WTI Purchased Put	22,000	54.17
WTI Sold Call	22,000	64.85
WTI Sold Put	22,000	44.26
Jan 1, 2020 – Dec 31, 2020		
WTI Purchased Put	6,000	56.00
WTI Sold Call	6,000	70.33
WTI Sold Put	6,000	46.67

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

Natural Gas Instruments:

Instrument Type(1)	MMcf/day	US$/Mcf
Apr 1, 2018 – Oct 31, 2018		
NYMEX Purchased Put	40.0	2.75
NYMEX Sold Call	40.0	3.38
Nov 1, 2018 – Dec 31, 2018		
NYMEX Purchased Put	30.0	2.75
NYMEX Sold Call	30.0	3.47

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

Electricity Instruments:

Instrument Type	MWh	CDN$/Mwh
Apr 1, 2018 – Apr 30, 2018		
AESO Power Swap(1)	3.0	59.25
May 1, 2018 – Jun 30, 2018		
AESO Power Swap(1)	5.0	57.55
Jul 1, 2018 – Aug 30, 2018		
AESO Power Swap(1)	2.0	55.00

(1) Alberta Electrical System Operator (“AESO”) fixed pricing.

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, 2018, Enerplus did not have any foreign exchange derivatives outstanding.

Interest Rate Risk:

As of March 31, 2018, 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 14. Enerplus has entered into various equity swaps maturing 2018 and has effectively fixed the future settlement cost on 470,000 shares at weighted average price of $16.89 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, 2018, approximately 87% 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, 2018 was $3.5 million (December 31, 2017 - $3.5 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 restricted cash) 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, access to capital markets, and acquisition and divestment activity.

At March 31, 2018, Enerplus was in full compliance with all covenants under the bank credit facility and outstanding senior notes.

16) CONTINGENCIES

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

17) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

	Three months ended March 31,	
($ thousands)	2018	2017
Accounts receivable	$ (6,637)	$ 21,672
Other current assets	1,621	(4,311)
Accounts payable	12,485	(6,817)
	$ 7,469	$ 10,544

b) Changes in Other Non-Cash Working Capital

($ thousands)	Three months ended March 31, 2018	2017
Non-cash financing activities[1]	$ 26	$ 16
Non-cash investing activities[2]	44,660	26,322

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

c) Other

($ thousands)	Three months ended March 31, 2018	2017
Income taxes paid/(received)	$ (85)	$ 65
Interest paid	3,256	3,644

BOARD OF DIRECTORS

Elliott Pew(1)(2)
Corporate Director
Boerne, Texas

David H. Barr(9)(12)
Corporate Director
The Woodlands, Texas

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)
Corporate Director
Calgary, Alberta

Susan M. MacKenzie(5)(7)(11)
Corporate Director
Calgary, Alberta

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

Jeffrey W. Sheets(5)(11)
Corporate Director
Houston, Texas

Sheldon B. Steeves(5)(8)
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

Eric G. Le Dain
Senior Vice President, Corporate Development, Commercial

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

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AUDITORS

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New York Stock Exchange: ERF

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ABBREVIATIONS

AECO	a reference to the physical storage and trading hub on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta Index prices
bbl(s)/day	barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons
Bcf	billion cubic feet
Bcfe	billion cubic feet equivalent
BOE	barrels of oil equivalent
Brent	crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $US dollars
LTI	long-term incentive
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MMbbl(s)	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British Thermal Units
MMcf	million cubic feet
MSW	mixed sweet blend
MWh	megawatt hour(s) of electricity
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange, the benchmark for North American natural gas pricing
OCI	other comprehensive income
SBC	share based compensation
U.S. GAAP	accounting principles generally accepted in the United States of America
WCS	Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing purposes
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

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