enerPLUS

Q3 2018

Third Quarter Report

Nine Months Ended September 30, 2018

SELECTED FINANCIAL RESULTS	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Financial (000's)				
Net Income/(Loss)	$ 86,923	$ 16,131	$ 128,964	$ 221,726
Adjusted Funds Flow[4]	210,351	90,386	539,221	324,505
Dividends to Shareholders - Declared	7,355	7,264	22,022	21,769
Debt Outstanding - net of Cash and Restricted Cash	313,591	318,273	313,591	318,273
Capital Spending	193,264	119,102	521,818	341,188
Property and Land Acquisitions	1,702	2,222	16,366	9,471
Property Divestments	(762)	(1,361)	6,026	57,581
Net Debt to Adjusted Funds Flow Ratio[4]	0.4x	0.7x	0.4x	0.7x
Financial per Weighted Average Shares Outstanding				
Net Income - Basic	$ 0.35	$ 0.07	$ 0.53	$ 0.92
Net Income - Diluted	0.35	0.07	0.52	0.90
Weighted Average Number of Shares Outstanding (000's) - Basic	245,235	242,129	244,659	241,854
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 52.32	$ 33.23	$ 48.03	$ 35.21
Royalties and Production Taxes	(13.39)	(7.98)	(12.03)	(8.28)
Commodity Derivative Instruments	(2.68)	0.40	(1.32)	0.51
Cash Operating Expenses	(6.80)	(6.73)	(7.01)	(6.39)
Transportation Costs	(3.70)	(3.61)	(3.60)	(3.74)
General and Administrative Expenses	(1.35)	(1.61)	(1.49)	(1.67)
Cash Share-Based Compensation	0.02	(0.10)	(0.09)	(0.04)
Interest, Foreign Exchange and Other Expenses	(0.81)	(1.17)	(0.94)	(1.25)
Current Income Tax Recovery/(Expense)	(0.01)	(0.01)	(0.01)	(0.10)
Adjusted Funds Flow[4]	$ 23.60	$ 12.42	$ 21.54	$ 14.25

SELECTED OPERATING RESULTS	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Average Daily Production[2]				
Crude Oil (bbls/day)	48,867	35,245	43,892	35,102
Natural Gas Liquids (bbls/day)	4,563	3,681	4,487	3,659
Natural Gas (Mcf/day)	260,591	241,212	259,629	267,852
Total (BOE/day)	96,861	79,128	91,651	83,403
% Crude Oil and Natural Gas Liquids	55%	49%	53%	46%
Average Selling Price [2][3]				
Crude Oil (per bbl)	$ 83.98	$ 54.21	$ 78.58	$ 55.75
Natural Gas Liquids (per bbl)	25.95	26.22	28.85	29.09
Natural Gas (per Mcf)	3.22	2.58	3.14	3.26
Net Wells Drilled	17	10	49	39

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

Average Benchmark Pricing	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
WTI crude oil (US$/bbl)	$ 69.50	$ 48.20	$ 66.75	$ 49.47
Brent (ICE) crude oil (US$/bbl)	75.97	52.18	72.68	52.59
AECO natural gas– monthly index (CDN$/Mcf)	1.35	2.04	1.41	2.58
NYMEX natural gas – last day (US$/Mcf)	2.90	3.00	2.90	3.17
USD/CDN average exchange rate	1.31	1.25	1.29	1.31

Share Trading Summary For the three months ended September 30, 2018	CDN[1] - ERF (CDN$)	U.S.[2] - ERF (US$)
High	$ 18.04	$ 13.87
Low	$ 14.51	$ 11.03
Close	$ 15.95	$ 12.34

(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
Second Quarter Total	$ 0.03	$ 0.02
Third Quarter Total	$ 0.03	$ 0.02
Total Year to Date	$ 0.09	$ 0.06

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

NEWS RELEASE

Highlights:

- Total production of 96,861 BOE per day in Q3, up 4% from the prior quarter
- Liquids production of 53,430 barrels per day in Q3, up 7% from the prior quarter
- Generated adjusted funds flow of $210 million during Q3, an increase of 21% from the prior quarter
- 2018 annual production guidance revised to the upper-end of the prior ranges, now 92,500 to 93,000 BOE per day with 49,500 to 50,000 barrels per day of liquids
- 2018 annual liquids production growth projected to be 22% at the midpoint of guidance
- 2018 capital spending guidance unchanged at $585 million
- Repurchased 1.6 million common shares in September and October for $25 million
- Visibility to meaningful free cash flow in Q4 2018
- Encouraging results from four DJ Basin appraisal wells (three Codell, one Niobrara)
- Reduced cash G&A guidance by $0.05 per BOE to $1.50 per BOE
- Balance sheet remains among the strongest in the peer group with a net debt to adjusted funds flow ratio of 0.4 times

"With our third quarter results, we are on track in 2018 to generate robust double-digit returns on capital employed, deliver over 20% liquids production growth and generate meaningful free cash flow," stated Ian C. Dundas, President and Chief Executive Officer. "At the same time, we are maintaining top-quartile balance sheet strength."

"In addition to our dividend, we continued returning capital to shareholders through share repurchases in the third quarter and have repurchased $25 million in stock since September. Based on current market conditions, we expect to continue to allocate a portion of our free cash flow to repurchase shares", noted Dundas.

Third Quarter Financial and Operational Summary

PRODUCTION

Third quarter production averaged 96,861 BOE per day, an increase of 4% from the second quarter. Liquids production for the quarter averaged 53,430 barrels per day (91% crude oil and 9% natural gas liquids), an increase of 7% from the second quarter. This represents growth of 22% on total production and 37% on liquids production compared to the same period in 2017.

Capital activity for the remainder of the year will be largely focused on drilling in North Dakota in preparation for the 2019 program. Enerplus expects flat to modest sequential oil production growth in the fourth quarter and is providing fourth quarter liquids production guidance of 53,500 to 54,500 barrels per day. Full year 2018 production guidance is revised to 92,500 to 93,000 BOE per day, with liquids production guidance revised to 49,500 to 50,000 barrels per day, the upper end of the prior ranges. The guidance implies 22% annual liquids production growth in 2018 at the midpoint.

NET INCOME AND ADJUSTED FUNDS FLOW

Enerplus generated net income of $86.9 million in the third quarter of 2018, an increase of $74.5 million from the previous quarter due to lower non-cash mark-to-market losses on the Company's commodity derivative instruments and higher realized commodity prices and production.

Adjusted funds flow was $210.4 million during the third quarter, up 21% from the second quarter. This was driven by higher realized crude oil and natural gas prices and higher production in the third quarter. This represents adjusted funds flow growth of over 130% compared to the same period in 2017.

PRICING REALIZATIONS AND COST STRUCTURE

Enerplus' realized Bakken oil price differential averaged US$2.54 per barrel below WTI in the third quarter, an improvement from US$3.42 per barrel below WTI in the prior quarter.

For the fourth quarter of 2018, Enerplus has fixed physical differential sales of 20,250 barrels per day of Bakken oil production at approximately US$2.53 per barrel below WTI. Its remaining production is sold on a monthly basis into the highest netback markets available. With spot Bakken differentials widening to date in the fourth quarter, Enerplus is revising its annual average Bakken differential guidance to US$3.80 per barrel below WTI, from US$3.50 per barrel below WTI previously.

For 2019, the Company has recently added additional fixed differential contracts and now has physical differential sales of approximately 16,000 barrels per day for its Bakken oil production at approximately US$3.00 per barrel below WTI.

The Company's realized third quarter Marcellus natural gas price differential was US$0.48 per Mcf below NYMEX, a 30% improvement from the second quarter.

Third quarter operating expenses were $6.81 per BOE, a decrease from $7.20 per BOE in the second quarter. Transportation costs of $3.70 per BOE were 4% higher than the prior quarter. Cash general and administrative ("G&A") expenses of $1.35 per BOE were 6% lower compared to the prior quarter. Enerplus is reducing its 2018 cash G&A expense guidance by $0.05 per BOE to $1.50 per BOE.

CAPITAL EXPENDITURES AND BALANCE SHEET POSITION

Exploration and development capital spending in the third quarter was $193.3 million and was associated with drilling 16.8 net wells and bringing 23.4 net wells on production across the Company. Through the first nine months of 2018, capital expenditures have totaled $521.8 million. Capital activity in the fourth quarter will be largely focused on drilling in North Dakota in preparation for the 2019 program. Enerplus has reaffirmed its 2018 capital budget of $585 million.

Total debt net of cash at September 30, 2018 was $313.6 million. Total debt was comprised of $661.2 million of senior notes outstanding. The Company was undrawn on its $800 million bank credit facility and had a cash balance of $347.6 million. At September 30, 2018, Enerplus' net debt to adjusted funds flow ratio was 0.4 times. Subsequent to the quarter, the Company renewed its $800 million bank credit facility for one year, maturing October 31, 2021.

SHARE REPURCHASE

During the third quarter, Enerplus repurchased 544,300 common shares under its Normal Course Issuer Bid at an average share price of $15.54. Subsequent to the end of the third quarter, the Company repurchased an additional 1,071,366 common shares at an average share price of $15.42. In total, the Company has repurchased 1,615,666 shares in 2018 for a cost of $25.0 million.

Based on current market conditions, Enerplus expects to continue to repurchase shares using a portion of its free cash flow.

Average Daily Production(1)

	Three months ended September 30, 2018				Nine months ended September 30, 2018			
	Crude Oil (Mbbl/d)	NGL (Mbbl/d)	Natural Gas (MMcf/d)	Total (Mboe/d)	Crude Oil (Mbbl/d)	NGL (Mbbl/d)	Natural Gas (MMcf/d)	Total (Mboe/d)
Williston Basin	38.9	3.6	25.8	46.7	34.2	3.4	23.6	41.5
Marcellus	—	—	210.3	35.0	—	—	207.0	34.5
Canadian Waterfloods	9.0	0.1	3.5	9.7	9.1	0.1	4.2	9.9
DJ Basin	0.8	—	—	0.8	0.4	—	—	0.4
Other(2)	0.2	0.9	21.1	4.6	0.2	1.0	24.7	5.3
Total	**48.9**	**4.6**	**260.6**	**96.9**	**43.9**	**4.5**	**259.6**	**91.7**

(1) Table may not add due to rounding.
(2) Nine months ended September 30, 2018 includes approximately 600 boe/d of production from Canadian natural gas properties sold in Q1 2018.

Summary of Wells Brought On-Stream(1)

	Three months ended September 30, 2018				Nine months ended September 30, 2018			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	18.0	16.3	6.0	1.8	37.0	31.8	9.0	2.4
Marcellus	—	—	9.0	1.9	—	—	34.0	5.2
Canadian Waterfloods	—	—	1.0	—	2.0	1.9	1.0	—
DJ Basin	4.0	3.2	—	—	4.0	3.2	—	—
Other	—	—	1.0	0.2	—	—	2.0	0.4
Total	**22.0**	**19.5**	**17.0**	**3.9**	**43.0**	**36.9**	**46.0**	**8.1**

(1) Table may not add due to rounding.

ASSET ACTIVITY

WILLISTON BASIN

Williston Basin production averaged 46,709 BOE per day (83% oil) during the third quarter of 2018, up 7% from the second quarter of 2018. Third quarter Williston Basin production was comprised of 43,390 BOE per day in North Dakota, and 3,319 BOE per day in Montana.

Enerplus brought on-stream 18 gross operated wells (91% average working interest, 15 two-mile laterals and 3 one-mile laterals) across four pads at Fort Berthold during the third quarter. The average peak 30-day production rates per well was 1,513 BOE per day (78% oil, on a three-stream basis) with an average completed lateral length per well at 8,600 feet.

The Company drilled 11 gross operated wells (91% average working interest) in the third quarter.

The Company continues to run two operated drilling rigs at Fort Berthold.

MARCELLUS

Marcellus production averaged 210 MMcf per day during the third quarter, an increase of 4% from the previous quarter.

Nine gross non-operated wells (22% average working interest) were brought on-stream during the quarter with an average completed lateral length of 6,500 feet per well and average peak 30-day production rates per well of 15.4 MMcf per day.

The Company participated in drilling 15 gross non-operated wells (15% average working interest) during the third quarter.

CANADIAN WATERFLOODS

Canadian waterflood production averaged 9,670 BOE per day (93% oil) during the third quarter, largely flat to the previous quarter. Capital activity in the third quarter was primarily focused on the Company's drilling program at Medicine Hat.

DJ BASIN

Enerplus brought on production four gross (3.2 net) operated wells in the DJ Basin during the third quarter. In total, the Company has drilled five gross (4.2 net) wells in the play including its first well, Maple 8-67-36-25C, which has produced approximately 100,000 barrels of oil (130,000 BOE, three-stream basis) in its first 12 producing months. Results from the additional four wells completed during the third quarter are encouraging with all four wells meeting or tracking above the Maple well's performance. On average, the wells have each produced 29,700 barrels of oil in their first 90 days with peak 90-day average production rates per well of 330 barrels of oil per day. On a three-stream basis, based on estimated natural gas production and NGL yield, the wells have produced 37,400 BOE per well in their first 90 days with peak 90-day average production rates per well of 415 BOE per day. The wells are on track to produce 100,000 barrels of oil in 12 months on production - competitive with other recent wells in the basin.

Three of the wells were completed in the Codell formation with one well completed in the Niobrara formation. The Niobrara well, Cherry Creek 8-67-28-27N, has been among the strongest performing wells and has given the Company further confidence in the prospectivity of the Niobrara across a portion of the Company's acreage, with the potential to materially add to the scope of the asset.

With positive well results and a supportive regulatory environment, Enerplus plans to continue delineation drilling and progressing midstream options in 2019. The Company will provide a further update regarding its 2019 capital plans in connection with its 2019 budget.

Updated Fourth Quarter and Full Year 2018 Guidance

The Company has provided fourth quarter production guidance, revised its annual average production guidance, and reduced its cash G&A guidance. All other guidance remains unchanged.

	Guidance
Capital spending	$585 million
Average annual production	92,500 – 93,000 BOE/day (from 91,000 – 93,000 BOE/day)
Average annual crude oil and natural gas liquids production	49,500 – 50,000 bbls/day (from 49,000 – 50,000 bbls/day)
Fourth quarter average crude oil and natural gas liquids production	53,500 – 54,500 bbls/day
Average royalty and production tax rate	25%
Operating expense	$7.00/BOE
Transportation expense	$3.60/BOE
Cash G&A expense	$1.50/BOE (from $1.55/BOE)

2018 Full-Year Differential/Basis Outlook[1]	
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.80)/bbl (from US$(3.50)/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 23,000 barrels per day of crude oil protected for the remainder of 2018, 23,140 barrels per day protected in 2019, and 16,000 barrels per day protected in 2020.

For natural gas, Enerplus has 33,370 Mcf per day protected for the fourth quarter of 2018 using collar structures.

Commodity Hedging Detail (As at October 30, 2018)

	WTI Crude Oil (US$/bbl)[1]						NYMEX Natural Gas (US$/Mcf)[1]	
	Oct 1, 2018 – Dec 31, 2018	Jan 1, 2019 – Mar 31, 2019	Apr 1, 2019 – Jun 30, 2019	Jul 1, 2019 – Sep 30, 2020	Oct 1, 2019 – Dec 31, 2019	Jan 1, 2020 – Dec 31, 2020	Oct 1, 2018 – Oct 31, 2018	Nov 1, 2018 – Dec 31, 2018
Swaps								
Sold Swaps	$ 53.73	$ 53.73	—	—	—	—	—	—
Volume (bbls/d or Mcf/d)	3,000	3,000	—	—	—	—	—	—
Three Way Collars[2]								
Sold Puts	$ 42.74	$ 44.28	$ 44.50	$ 44.64	$ 44.64	$ 46.88	—	—
Volume (bbls/d or Mcf/d)	20,000	17,000	23,500	24,500	24,500	16,000	—	—
Purchased Puts	$ 52.48	$ 54.12	$ 54.59	$ 54.81	$ 54.81	$ 57.50	$ 2.75	$ 2.75
Volume (bbls/d or Mcf/d)	20,000	17,000	23,500	24,500	24,500	16,000	40,000	30,000
Sold Calls	$ 61.10	$ 64.12	$ 65.52	$ 65.95	$ 65.99	$ 72.50	$ 3.38	$ 3.47
Volume (bbls/d or Mcf/d)	20,000	17,000	23,500	24,500	24,500	16,000	40,000	30,000

(1) Based on weighted average price (before premiums).
(2) The total average deferred premium spent on the three-way collars is US$1.60/bbl from October 1, 2018 to December 31, 2020

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

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

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

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

This news release contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "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; and expectations regarding our share repurchase program, including sources of funds therefrom.*

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 initial production performance referenced should be considered preliminary data and such data is not necessarily indicative of long-term performance, or of ultimate recovery; 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 the following forward prices: WTI US$66.86/bbl, NYMEX US$2.96/Mcf, and a USD/CDN exchange rate of 1.29. 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 purpose of our free cash flow guidance is to assist readers in understanding our expected and targeted financial results, and this information may not be appropriate for other purposes.

The forward-looking information contained in this 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", "free cash flow", "net debt to adjusted funds flow ratio" and "total debt net of cash" as measures to analyze operating performance, leverage and liquidity. "Adjusted funds flow" is calculated as net cash generated from operating activities but before changes in non-cash operating working capital and asset retirement obligation expenditures. "Net debt to adjusted funds flow ratio" is calculated as total debt net of cash and restricted cash, divided by a trailing 12 months of adjusted funds flow. "Total debt net of cash" is calculated as senior notes plus any outstanding bank credit facility balance, minus cash and restricted cash. Free cash flow is defined as "Adjusted funds flow less exploration and development capital spending". Calculation of these terms is described in Enerplus' MD&A under the "Liquidity and Capital Resources" section.

Enerplus believes that, in addition to net earnings and other measures prescribed by U.S. GAAP, the terms "adjusted funds flow", "free cash flow", "net debt to adjusted funds flow", and "total debt net of cash" are useful supplemental measures as they provide an indication of the results generated by Enerplus' principal business activities. However, these measures are not measures recognized by U.S. GAAP and do not have a standardized meaning prescribed by U.S. GAAP. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers. For reconciliation of these measures to the most directly comparable measure calculated in accordance with U.S. GAAP, and further information about these measures, see disclosure under "Non-GAAP Measures" in Enerplus' Third Quarter 2018 MD&A.

Electronic copies of Enerplus Corporation's Third 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 November 8, 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 and nine months ended September 30, 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 thereto have been prepared in accordance with U.S. GAAP, including the prior period comparatives. All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included in the Interim Financial Statements. Certain prior period amounts have been restated to conform with current period presentation.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 bbl and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcf. BOE and Mcfe measures are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. 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

Production for the third quarter averaged 96,861 BOE/day, a 4% increase compared to the second quarter of 2018. Our crude oil and natural gas liquids production increased by 7% to 53,430 bbls/day from 50,050 bbls/day in the second quarter of 2018. The increase in production is primarily due to strong well performance in North Dakota with 18.1 net wells coming on-stream during the third quarter as well as 3.2 net wells coming on-stream in Colorado. As a result, we are revising our average annual production guidance range to 92,500 – 93,000 BOE/day, the high end of our previous range of 91,000 – 93,000 BOE/day. We are also revising our average annual crude oil and liquids guidance range to 49,500 – 50,000 bbls/day, the high end of our previous range of 49,000 – 50,000 bbls/day and guiding to a fourth quarter average crude oil and liquids production range of 53,500 – 54,500 bbls/day.

Capital expenditures totaled $193.3 million for the third quarter and $521.8 million year to date, in line with our expectations. Approximately 75% of our capital spending year to date has been directed to our North Dakota crude oil properties. We are maintaining our annual capital spending guidance of $585 million. Capital activity for the remainder of the year will be largely focused on drilling in North Dakota in preparation for the 2019 program.

Operating costs for the quarter decreased to $6.81/BOE from $7.20/BOE in the second quarter, primarily due to our North Dakota operations where we saw reduced well service activity and lower gas handling costs in the third quarter. We are maintaining our annual operating cost guidance of $7.00/BOE.

Cash G&A expenses for the third quarter were $1.35/BOE, a decrease of 6% from $1.44/BOE in the second quarter of 2018. Cash G&A expenses per BOE decreased from the second quarter with higher production during the period. We are lowering our annual guidance target for cash G&A expenses to $1.50/BOE from $1.55/BOE.

As of October 30, 2018, we had approximately 68% of our forecasted crude oil production, net of royalties, hedged for the remainder of 2018, and approximately 68% and 47% of our crude oil production, net of royalties, hedged in 2019 and 2020, respectively, based on 2018 forecasted net production. We have also hedged approximately 17% of our forecasted natural gas production, net of royalties, for the remainder of 2018. In addition, we have physical sales contracts in place in the Bakken for 20,250 bbls/day of production at an average differential of US$2.53/bbl below WTI for the fourth quarter of 2018, and on 16,000 bbls/day of production in 2019 averaging approximately US$3.00/bbl below WTI.

We recorded net income of $86.9 million and adjusted funds flow of $210.4 million in the third quarter of 2018, compared to $12.4 million and $173.7 million, respectively, in the second quarter of 2018. Net income in the third quarter increased with higher realized commodity prices and production, as well as lower non-cash mark-to-market losses recorded on our commodity derivative instruments.

During the quarter, we repurchased and cancelled 544,300 common shares under our Normal Course Issuer Bid ("NCIB").

At September 30, 2018, our total debt net of cash was $313.6 million and our net debt to adjusted funds flow ratio was 0.4x.

RESULTS OF OPERATIONS

Production

Average daily production for the third quarter totaled 96,861 BOE/day, an increase of 3,978 BOE/day or 4% compared to the second quarter of 2018. Crude oil and natural gas liquids production increased by 7%, primarily due to our successful capital program focused on our U.S. crude oil properties. Natural gas production also increased in the period with less downtime and pipeline maintenance in the Marcellus when compared to the second quarter.

For the three and nine months ended September 30, 2018, crude oil and liquids production increased by 14,504 bbls/day or 37% and 9,618 bbls/day or 25%, respectively, compared to the same periods in 2017. Production increased primarily due to higher spending in North Dakota where 34.3 net wells have been brought on-stream year to date. Natural gas production increased by 8% for the three months ended September 30, 2018 compared to the same period in 2017 with increased activity in the Marcellus as a result of stronger realized prices and additional pipeline capacity coming on-stream in the basin. For the nine-month period ending September 30, 2018, natural gas production decreased by 3% due to non-core Canadian asset divestments in 2017.

Our crude oil and natural gas liquids weighting increased to 55% in the third quarter of 2018, from 49% for the same period of 2017, as a result of growth from our North Dakota crude oil assets in 2018 and the divestment of non-core Canadian natural gas weighted properties in 2017.

Average daily production volumes for the three and nine months ended September 30, 2018 and 2017 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2018**	**2017**	**% Change**	**2018**	**2017**	**% Change**
Crude oil (bbls/day)	48,867	35,245	39%	43,892	35,102	25%
Natural gas liquids (bbls/day)	4,563	3,681	24%	4,487	3,659	23%
Natural gas (Mcf/day)	260,591	241,212	8%	259,629	267,852	(3%)
Total daily sales (BOE/day)	96,861	79,128	22%	91,651	83,403	10%

We are revising our average annual production guidance range to 92,500 – 93,000 BOE/day, the high end of our previous range of 91,000 – 93,000 BOE/day. We are also revising our average annual crude oil and liquids guidance range to 49,500 – 50,000 bbls/day, the high end of our previous range of 49,000 – 50,000 bbls/day, and guiding to a fourth quarter average crude oil and liquids production range of 53,500 – 54,500 bbls/day.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, adjusted funds flow and financial condition. The following table compares quarterly average prices for the nine months ended September 30, 2018 and 2017 and other periods indicated:

	Nine months ended September 30,						
Pricing (average for the period)	**2018**	**2017**	**Q3 2018**	**Q2 2018**	**Q1 2018**	**Q4 2017**	**Q3 2017**
Benchmarks							
WTI crude oil (US$/bbl)	$ 66.75	$ 49.47	$ 69.50	$ 67.88	$ 62.87	$ 55.40	$ 48.20
Brent (ICE) crude oil (US$/bbl)	72.68	52.59	75.97	74.90	67.18	61.54	52.18
NYMEX natural gas – last day (US$/Mcf)	2.90	3.17	2.90	2.80	3.00	2.93	3.00
AECO natural gas – monthly index ($/Mcf)	1.41	2.58	1.35	1.02	1.85	1.96	2.04
USD/CDN average exchange rate	1.29	1.31	1.31	1.29	1.26	1.27	1.25
USD/CDN period end exchange rate	1.29	1.25	1.29	1.31	1.29	1.26	1.25
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 78.58	$ 55.75	$ 83.98	$ 79.98	$ 69.67	$ 65.91	$ 54.21
Natural gas liquids ($/bbl)	28.85	29.09	25.95	32.23	28.13	32.26	26.22
Natural gas ($/Mcf)	3.14	3.26	3.22	2.68	3.50	3.03	2.58
Average differentials							
Brent (ICE) – WTI (US$/bbl)	$ 5.93	$ 3.12	$ 6.47	$ 7.02	$ 4.31	$ 6.14	$ 3.98
MSW Edmonton – WTI (US$/bbl)	(6.06)	(2.90)	(6.83)	(5.45)	(5.89)	(1.14)	(2.89)
WCS Hardisty – WTI (US$/bbl)	(21.93)	(11.88)	(22.25)	(19.27)	(24.28)	(12.27)	(9.94)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.73)	(0.84)	(0.61)	(0.91)	(0.67)	(1.32)	(1.29)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(0.81)	(0.91)	(0.68)	(0.99)	(0.76)	(1.40)	(1.36)
AECO monthly – NYMEX (US$/Mcf)	(1.80)	(1.21)	(1.87)	(2.00)	(1.44)	(1.40)	(1.39)
Enerplus realized differentials(1)(2)							
Bakken crude oil – WTI (US$/bbl)	$ (3.03)	$ (4.69)	$ (2.54)	$ (3.42)	$ (3.27)	$ (1.61)	$ (3.24)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.46)	(0.75)	(0.48)	(0.69)	(0.21)	(0.81)	(1.02)
Canada crude oil – WTI (US$/bbl)	(17.86)	(11.09)	(16.61)	(16.31)	(20.82)	(10.47)	(9.29)
Canada natural gas – NYMEX (US$/Mcf)	(0.82)	(0.63)	(0.77)	(1.18)	(0.52)	(0.56)	(1.00)

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

CRUDE OIL AND NATURAL GAS LIQUIDS

Our average realized crude oil price during the third quarter of 2018 increased by 5%, compared to the second quarter of 2018, averaging $83.98/bbl. Crude oil prices were volatile during the third quarter, however, benchmark WTI crude oil prices increased by 2%. The volatility was largely related to concerns over trade conflict and supply uncertainty, due to ongoing geopolitical issues and growth in U.S. production. Continued strength in Bakken differentials offset lower prices realized for our Canadian crude oil production during the quarter.

Our realized Bakken price differential improved by 26% during the quarter to average US$2.54/bbl below WTI and averaged US$3.03/bbl below WTI year to date. Subsequent to the quarter, a significant amount of Midwest U.S. refining capacity was taken off-line for scheduled seasonal maintenance. This resulted in weaker Bakken prices contracted for November and December versus previous months. We have physical sales contracts in place for approximately 20,250 bbls/day of Bakken crude oil production at an average differential of US$2.53/bbl below WTI for the fourth quarter that is expected to provide some protection from this short-term seasonal weakness in pricing. As a result of the weaker differentials in the fourth quarter, we are revising our full year Bakken differential guidance to average approximately US$3.80/bbl below WTI. For 2019, we have physical sales contracts in place for approximately 16,000 bbls/day of Bakken crude oil production with fixed differentials averaging approximately US$3.00/bbl below WTI.

Our realized price differential for our Canadian crude oil production widened by US$0.30/bbl compared to the second quarter of 2018. Canadian crude oil prices weakened significantly late in the third quarter as seasonal U.S. refinery maintenance and growing Canadian crude oil production placed constraints on Canadian pipeline capacity and increased demand for rail to transport production out of the region. We have fixed differential hedges in place for 3,000 bbl/day of our Canadian heavy crude oil production at an average differential of US$14.46/bbl below WTI for the remainder of 2018, which is expected to continue to provide some protection against this price weakness.

Our realized price for natural gas liquids averaged $25.95/bbl during the period, which represents a 19% decrease compared to the previous quarter, due to lower condensate prices in both the U.S. and Canada.

NATURAL GAS

Our average realized natural gas price during the third quarter of 2018 increased by 20% compared to the second quarter of 2018, to average $3.22/Mcf. The increase was mainly due to continued improvement in Marcellus in basin prices. Our realized Marcellus sales differential, excluding transportation and gathering costs, averaged US$0.48/Mcf below NYMEX for the period. Strong demand for seasonal power generation resulted in lower than expected storage balances in the U.S., especially in the Northeastern region, which resulted in improved differentials. Further, basis differentials in the Marcellus continued to improve subsequent to the quarter as two new pipeline projects representing 2.7 Bcf/day of additional pipeline capacity were brought into service in early October. We are maintaining our full year differential guidance for the Marcellus of US$0.40/Mcf below NYMEX.

Benchmark AECO gas prices continue to remain weak during the third quarter of 2018 due to transportation constraints out of the basin. Our realized Canadian natural gas price differential averaged US$0.77/Mcf below NYMEX. We continue to benefit from our AECO/NYMEX physical sales contracts, which have an average fixed basis differential of US$0.63/Mcf below NYMEX.

FOREIGN EXCHANGE

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

The Canadian dollar was stronger during the first nine months with an average exchange rate of 1.29 USD/CDN compared to 1.31 USD/CDN for the same period in 2017. However, when comparing the exchange rate in the third quarter of 2018 to the second quarter, the Canadian dollar weakened relative to the U.S. dollar. This was due to concerns related to the impact of the ongoing North American Free Trade Agreement (“NAFTA”) negotiations, other U.S. policies related to trade, as well as interest rates in Canada and the U.S. that influenced the foreign exchange rate.

Price Risk Management

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

As of October 30, 2018, we have hedged approximately 23,000 bbls/day of our expected crude oil production for the remainder of 2018, which represents approximately 68% of our forecasted crude oil production, after royalties. For 2019, we are hedged on 23,140 bbls/day, which represents approximately 68% of our 2018 forecasted crude oil production, after royalties. For 2020, we have hedged 16,000 bbls/day, which represents 47% 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 October 30, 2018, we have hedged approximately 33,370 Mcf/day of our forecasted natural gas production for the remainder of 2018. This represents approximately 17% of our forecasted natural gas production, after royalties.

The following is a summary of our financial contracts in place at October 30, 2018, expressed as a percentage of our forecasted 2018 net production volumes:

	WTI Crude Oil (US$/bbl)(1)(2)			
	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	$ 53.73	$ 53.73	—	—
%	9%	9%	—	—
Three Way Collars(2)				
Sold Puts	$ 42.74	$ 44.28	$ 44.60	$ 46.88
%	59%	50%	71%	47%
Purchased Puts	$ 52.48	$ 54.12	$ 54.74	$ 57.50
%	59%	50%	71%	47%
Sold Calls	$ 61.10	$ 64.12	$ 65.82	$ 72.50
%	59%	50%	71%	47%

(1) Based on weighted average price (before premiums) assuming average annual production of 92,750 BOE/day, which is the mid-point of our updated annual 2018 guidance, less royalties and production taxes of 25%. A portion of the sold puts are settled annually rather than monthly.
(2) The total average deferred premium spent on our three way collars is US$1.60/bbl from October 1, 2018 to December 31, 2020.

	NYMEX Natural Gas (US$/Mcf)(1)
	Oct 1, 2018 – Dec 31, 2018
Collars	
Purchased Puts	$ 2.75
%	17%
Sold Calls	$ 3.43
%	17%

(1) Based on weighted average price (before premiums) assuming average annual production of 92,750 BOE/day, which is the mid-point of our updated annual 2018 guidance, less royalties and production taxes of 25%. A portion of the sold puts are settled annually rather than monthly.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	**Three months ended September 30,**		**Nine months ended September 30,**	
($ millions)	**2018**	**2017**	**2018**	**2017**
Cash gains/(losses):				
Crude oil	$ (24.3)	$ 2.9	$ (50.7)	$ 4.2
Natural gas	0.4	—	17.7	7.5
Total cash gains/(losses)	$ (23.9)	$ 2.9	$ (33.0)	$ 11.7
Non-cash gains/(losses):				
Crude oil	$ (30.0)	$ (37.4)	$ (130.8)	$ 34.2
Natural gas	(0.2)	0.3	(1.7)	9.4
Total non-cash gains/(losses)	$ (30.2)	$ (37.1)	$ (132.5)	$ 43.6
Total gains/(losses)	$ (54.1)	$ (34.2)	$ (165.5)	$ 55.3

	Three months ended September 30,		**Nine months ended September 30,**	
(Per BOE)	**2018**	**2017**	**2018**	**2017**
Total cash gains/(losses)	$ (2.68)	$ 0.40	$ (1.32)	$ 0.51
Total non-cash gains/(losses)	(3.39)	(5.10)	(5.29)	1.91
Total gains/(losses)	$ (6.07)	$ (4.70)	$ (6.61)	$ 2.42

During the third quarter of 2018, we realized cash losses of $24.3 million on our crude oil contracts and cash gains of $0.4 million on our natural gas contracts. In comparison, during the third quarter of 2017, we realized cash gains of $2.9 million on our crude oil contracts. Cash losses on our crude oil contracts were primarily due to crude oil prices rising above the swap level and the sold call strike price on our three way collar hedge positions.

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 third quarter of 2018, the fair value of our crude oil contracts was in a net liability position of $165.0 million, and the fair value of our natural gas contracts was nil. For the three and nine months ended September 30, 2018, the change in the fair value of our crude oil contracts represented losses of $30.0 million and $130.8 million, respectively, and our natural gas contracts represented losses of $0.2 million and $1.7 million, respectively.

Revenues

	Three months ended September 30,		**Nine months ended September 30,**	
($ millions)	**2018**	**2017**	**2018**	**2017**
Oil and natural gas sales	$ 466.4	$ 241.9	$ 1,201.8	$ 801.7
Royalties	(92.8)	(45.8)	(235.8)	(152.1)
Oil and natural gas sales, net of royalties	$ 373.6	$ 196.1	$ 966.0	$ 649.6

Oil and natural gas sales, net of royalties for the three and nine months ended September 30, 2018, were $373.6 million and $966.0 million, respectively, an increase of 91% and 49% from the same periods in 2017. The increase in revenue was a result of the improvement in crude oil and natural gas prices in the period, along with higher production when compared to the prior year.

Royalties and Production Taxes

($ millions, except per BOE amounts)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Royalties	$ 92.8	$ 45.8	$ 235.8	$ 152.1
Per BOE	$ 10.41	$ 6.29	$ 9.42	$ 6.68
Production taxes	$ 26.6	$ 12.3	$ 65.4	$ 36.5
Per BOE	$ 2.98	$ 1.69	$ 2.61	$ 1.60
Royalties and production taxes	$ 119.4	$ 58.1	$ 301.2	$ 188.6
Per BOE	$ 13.39	$ 7.98	$ 12.03	$ 8.28
Royalties and production taxes (% of oil and natural gas sales)	26%	24%	25%	24%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees and freehold mineral taxes. A large percentage of our production is from U.S. properties where royalty rates are generally higher than in Canada and less sensitive to commodity price levels. During the three and nine months ended September 30, 2018, royalties and production taxes increased to $119.4 million and $301.2 million, respectively, from $58.1 million and $188.6 million for the same periods in 2017 primarily due to higher U.S. crude oil sales.

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

Operating Expenses

($ millions, except per BOE amounts)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Cash operating expenses	$ 60.6	$ 48.9	$ 175.3	$ 145.4
Non-cash (gains)/losses(1)	0.1	(0.1)	—	(0.4)
Total operating expenses	$ 60.7	$ 48.8	$ 175.3	$ 145.0
Per BOE	$ 6.81	$ 6.71	$ 7.01	$ 6.37

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

For the three and nine months ended September 30, 2018, operating expenses were $60.7 million ($6.81/BOE) and $175.3 million ($7.01/BOE) respectively, compared to our annual guidance of $7.00/BOE. Operating costs increased from $48.8 million ($6.71/BOE) and $145.0 million ($6.37/BOE), respectively, when compared to the same periods in 2017. The increases were due to a higher weighting of crude oil and liquids production, as well as higher repairs and maintenance and water handling rates.

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

Transportation Costs

($ millions, except per BOE amounts)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Transportation costs	$ 33.0	$ 26.3	$ 90.1	$ 85.1
Per BOE	$ 3.70	$ 3.61	$ 3.60	$ 3.74

For the three and nine months ended September 30, 2018, transportation costs were $33.0 million ($3.70/BOE) and $90.1 million ($3.60/BOE) respectively, compared to our annual guidance of $3.60/BOE. During the same periods in 2017, transportation costs were $26.3 million ($3.61/BOE) and $85.1 million ($3.74/BOE), respectively. The increase in costs on a per BOE basis for the three months ended September 30, 2018 was due to a weakening Canadian dollar when compared to the prior period. The decrease in costs on a per BOE basis for the nine months ended September 30, 2018 resulted from increased North Dakota natural gas and natural gas liquids production in the U.S. with minimal associated transportation costs.

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.

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

Netbacks by Property Type	Three months ended September 30, 2017 Crude Oil	Natural Gas	Total
Average Daily Production	42,164 BOE/day	221,784 Mcfe/day	79,128 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 49.22	$ 2.50	$ 33.23
Royalties and production taxes	(12.13)	(0.54)	(7.98)
Cash operating expenses	(10.85)	(0.34)	(6.73)
Transportation costs	(2.35)	(0.84)	(3.61)
Netback before hedging	$ 23.89	$ 0.78	$ 14.91
Cash hedging gains/(losses)	0.75	—	0.40
Netback after hedging	$ 24.64	$ 0.78	$ 15.31
Netback before hedging ($ millions)	$ 92.7	$ 15.9	$ 108.6
Netback after hedging ($ millions)	$ 95.6	$ 15.9	$ 111.5

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

Netbacks by Property Type	Nine months ended September 30, 2017 Crude Oil	Natural Gas	Total
Average Daily Production	42,420 BOE/day	245,900 Mcfe/day	83,403 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 50.54	$ 3.22	$ 35.21
Royalties and production taxes	(12.87)	(0.59)	(8.28)
Cash operating expenses	(10.38)	(0.38)	(6.39)
Transportation costs	(2.40)	(0.85)	(3.74)
Netback before hedging	$ 24.89	$ 1.40	$ 16.80
Cash hedging gains/(losses)	0.36	0.11	0.51
Netback after hedging	$ 25.25	$ 1.51	$ 17.31
Netback before hedging ($ millions)	$ 288.3	$ 94.3	$ 382.6
Netback after hedging ($ millions)	$ 292.4	$ 101.9	$ 394.3

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

Crude oil netbacks before hedging for the three and nine months ended September 30, 2018 were higher compared to the same periods in 2017 primarily due to higher production and improved realized prices. For the three and nine months ended September 30, 2018, our crude oil properties accounted for 89% and 87% of our netback before hedging, respectively, compared to 85% and 75% for the three and nine-month periods ended 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 September 30,		Nine months ended September 30,	
($ millions)	2018	2017	2018	2017
Cash:				
G&A expense	$ 12.0	$ 11.7	$ 37.3	$ 37.9
Share-based compensation expense	(0.2)	0.7	2.2	0.9
Non-Cash:				
Share-based compensation expense	4.3	4.1	18.4	15.6
Equity swap loss/(gain)	0.2	(0.8)	(1.2)	0.2
Total G&A expenses	$ 16.3	$ 15.7	$ 56.7	$ 54.6

	Three months ended September 30,		Nine months ended September 30,	
(Per BOE)	2018	2017	2018	2017
Cash:				
G&A expense	$ 1.35	$ 1.61	$ 1.49	$ 1.67
Share-based compensation expense	(0.02)	0.10	0.09	0.04
Non-Cash:				
Share-based compensation expense	0.48	0.57	0.74	0.69
Equity swap loss/(gain)	0.02	(0.11)	(0.05)	0.01
Total G&A expenses	$ 1.83	$ 2.17	$ 2.27	$ 2.41

For the three and nine months ended September 30, 2018, cash G&A expenses were $12.0 million ($1.35/BOE) and $37.3 million ($1.49/BOE), respectively, compared to $11.7 million ($1.61/BOE) and $37.9 million ($1.67/BOE) for the same periods in 2017. Cash G&A expenses were essentially flat but decreased on a per BOE basis for the three and nine months ended September 30, 2018 compared to the same periods in 2017, due to higher production.

During the third quarter of 2018, we reported a cash SBC recovery of $0.2 million due to the decrease in our share price on outstanding deferred share units. We recorded non-cash SBC of $4.3 million or $0.48/BOE in the third quarter of 2018, which is consistent with an expense of $4.1 million or $0.57/BOE during the same period in 2017.

We have hedges in place on a portion of the outstanding cash-settled grants under our LTI plans. In the third quarter we recorded a non-cash mark-to-market loss of $0.2 million on these hedges due to the decrease in our share price. We had 195,000 units outstanding, hedged at a weighted average price of $20.60 per share at September 30, 2018.

We are lowering our annual cash G&A guidance to $1.50/BOE from $1.55/BOE due to higher annual average production.

Interest Expense

For the three and nine months ended September 30, 2018, we recorded total interest expense of $8.6 million and $27.0 million, respectively, compared to $8.7 million and $29.0 million for the same periods in 2017. The decrease in interest expense for the nine months ended September 30, 2018 compared to the same period in 2017 was primarily due to the repayment of a portion of our 2009 senior notes which carry a higher coupon rate, along with the impact of a strengthening Canadian dollar on our U.S. dollar denominated interest expense.

At September 30, 2018, we were undrawn on our $800 million bank credit facility and our debt balance consisted of fixed interest rates, with a weighted average interest rate of 4.8%. See Note 8 to the Interim Financial Statements for further details.

Foreign Exchange

($ millions)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Realized:				
Foreign exchange (gain)/loss on settlements	$ 0.3	$ 0.5	$ 0.6	$ 1.5
Translation of U.S. dollar cash held in Canada (gain)/loss	4.3	13.5	(6.8)	13.5
Unrealized (gain)/loss	(12.2)	(31.6)	17.9	(48.6)
Total foreign exchange (gain)/loss	$ (7.6)	$ (17.6)	$ 11.7	$ (33.6)
USD/CDN average exchange rate	1.31	1.25	1.29	1.31
USD/CDN period end exchange rate	1.29	1.25	1.29	1.25

For the three and nine months ended September 30, 2018, we recorded a foreign exchange gain of $7.6 million and loss of $11.7 million, respectively, compared to gains of $17.6 million and $33.6 million for the same periods 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 September 30, 2018 to December 31, 2017, the Canadian dollar weakened relative to the U.S. dollar, resulting in an unrealized loss of $17.9 million. See Note 12 to the Interim Financial Statements for further details.

Capital Investment

($ millions)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Capital spending	$ 193.3	$ 119.1	$ 521.8	$ 341.2
Office capital	1.6	0.5	5.3	1.0
Sub-total	194.9	119.6	527.1	342.2
Property and land acquisitions	$ 1.7	$ 2.2	$ 16.4	$ 9.5
Property divestments	0.8	1.4	(6.0)	(57.6)
Sub-total	2.5	3.6	10.4	(48.1)
Total [(1)]	$ 197.4	$ 123.2	$ 537.5	$ 294.1

(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 and nine months ended September 30, 2018, totaled $193.3 million and $521.8 million, respectively, compared to capital spending of $119.1 million and $341.2 million for the same periods in 2017. The increase is in line with our strategy to deliver production and liquids growth through 2018. During the quarter we spent $159.4 million on our U.S. crude oil properties, $18.6 million on our Marcellus natural gas assets and $14.5 million on our Canadian waterflood properties.

For the three and nine months ended September 30, 2018, we completed $1.7 million and $16.4 million, respectively, in property and land acquisitions which included minor acquisitions of leases and undeveloped land. Property divestments for the nine months ended September 30, 2018 were $6.0 million compared to divestments with proceeds of $57.6 million in 2017, consisting mainly of our Brooks waterflood property and Canadian shallow gas assets.

We continue to expect 2018 annual capital spending of $585 million. Capital activity for the remainder of the year will be largely focused on drilling in North Dakota in preparation for the 2019 program.

Depletion, Depreciation and Accretion (“DD&A”)

($ millions, except per BOE amounts)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
DD&A expense	$ 81.5	$ 59.8	$ 218.7	$ 185.1
Per BOE	$ 9.15	$ 8.21	$ 8.74	$ 8.13

DD&A of property, plant and equipment (“PP&E”) is recognized using the unit-of-production method based on proved reserves. The increase in DD&A per BOE compared to the same periods of 2017 was a result of increased 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 costs to be incurred in future periods. We have estimated the net present value of our asset retirement obligation to be $119.4 million at September 30, 2018, compared to $117.7 million at December 31, 2017. For the three and nine months ended September 30, 2018, asset retirement obligation settlements were $2.8 million and $8.1 million, respectively, compared to $3.1 million and $7.1 million during the same periods in 2017. See Note 9 to the Interim Financial Statements for further details.

Income Taxes

($ millions)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Current tax expense/(recovery)	$ 0.1	$ 0.1	$ 0.2	$ 2.2
Deferred tax expenses/(recovery)	15.0	(7.7)	30.7	59.4
Total tax expense/(recovery)	$ 15.1	$ (7.6)	$ 30.9	$ 61.6

For the three and nine months ended September 30, 2018, we recorded a total tax expense of $15.1 million and $30.9 million, respectively, compared to a recovery of $7.6 million and an expense of $61.6 million for the same periods in 2017. The increase in the total tax expense for the three months ended was primarily due to higher income in 2018 compared to the same period in 2017. The decrease in the total tax expense for the nine months ended was primarily due to lower net income in 2018 compared to the same period in 2017, as a result of commodity derivative hedging losses in 2018 compared to gains in 2017, and a gain of $78.4 million recorded on the divestment of assets in 2017. 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, share repurchases and dividend levels. We also assess our leverage relative to our most restrictive debt covenant under our bank credit facility and senior notes, which is a maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At September 30, 2018, our senior debt to adjusted EBITDA ratio was 0.9x and our net debt to adjusted funds flow ratio was 0.4x. 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 September 30, 2018 was $313.6 million, a decrease of 4% compared to $325.8 million at December 31, 2017. Total debt was comprised of $661.2 million of senior notes less $347.6 million in cash. At September 30, 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 96% and 102% for the three and nine months ended September 30, 2018, respectively, compared to 140% and 112% for the same periods in 2017.

For the three months ended September 30, 2018, the Company repurchased and cancelled 544,300 shares under our NCIB for a total cost of $8.5 million.

Our working capital deficiency, excluding cash and current deferred financial assets and liabilities, increased to $137.0 million at September 30, 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.

Subsequent to the quarter, we completed a one year extension of our $800 million senior, unsecured, covenant-based bank credit facility, which now matures on October 31, 2021. There were no significant amendments to the agreement terms or covenants. Drawn fees on the facility range between 125 and 315 basis points over Banker's Acceptance rates, with current drawn fees of 125 basis points over Banker's Acceptance rates based on our current reported senior net debt to adjusted EBITDA ratio. The bank credit facility ranks equally with our senior, unsecured covenant-based notes.

At September 30, 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 September 30, 2018:

Covenant Description		September 30, 2018
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA [1]	3.5x	0.9x
Total debt to adjusted EBITDA [1]	4.0x	0.9x
Total debt to capitalization	50%	19%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA [1][2]	3.0x - 3.5x	0.9x
Senior debt to consolidated present value of total proved reserves[3]	60%	25%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	20.0x

Definitions
"Senior debt" is calculated as the sum of drawn amounts on our bank credit facility, outstanding letters of credit and the principal amount of senior notes.
"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, impairment and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended September 30, 2018 was $214.8 million and $734.8 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 September 30,		Nine months ended September 30,	
($ millions, except per share amounts)	2018	2017	2018	2017
Dividends to shareholders	$ 7.4	$ 7.3	$ 22.0	$ 21.8
Per weighted average share (Basic)	$ 0.03	$ 0.03	$ 0.09	$ 0.09

During the three and nine months ended September 30, 2018, we reported total dividends of $7.4 million or $0.03 per share and $22.0 million or $0.09 per share, respectively, compared to $7.3 million or $0.03 per share and $21.8 million or $0.09 per share for the same periods 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

	Nine months ended September 30,	
	2018	2017
Share capital ($ millions)	$ 3,412.2	$ 3,386.9
Common shares outstanding (thousands)	244,764	242,129
Weighted average shares outstanding – basic (thousands)	244,659	241,854
Weighted average shares outstanding – diluted (thousands)	250,048	247,306

For the nine months ended September 30, 2018, a total of 640,086 shares were issued pursuant to our stock option plan resulting in additional share capital of $8.7 million, and a $0.7 million transfer from paid-in capital to share capital (2017 – nil). For the nine months ended September 30, 2018, a total of 2,539,498 shares were issued pursuant to our treasury-settled LTI plans and $23.4 million was transferred from paid-in capital to share capital (2017 – 1,646,017; $21.0 million).

During the three months ended September 30, 2018, the Company repurchased 544,300 common shares under the NCIB at an average price of $15.54 per share, for total consideration of $8.5 million. Of the amount paid, $7.6 million was recorded to share capital and $0.9 million was recorded to accumulated deficit. Subsequent to the quarter, the Company repurchased 1,071,366 common shares under the NCIB at an average price of $15.42 per share.

At November 8, 2018, we had 243,750,520 common shares outstanding. In addition, an aggregate of 11,326,078 common shares may be issued to settle outstanding grants under the Performance Share Unit ("PSU"), Restricted Share Unit, and stock option plans, assuming the maximum payout multiplier of 2.0 times for the PSUs.

For further details, see Note 14 to the Interim Financial Statements.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

($ millions, except per unit amounts)	Three months ended September 30, 2018 Canada	U.S.	Total	Three months ended September 30, 2017 Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	9,170	39,697	48,867	9,924	25,321	35,245
Natural gas liquids (bbls/day)	1,002	3,561	4,563	975	2,706	3,681
Natural gas (Mcf/day)	24,486	236,105	260,591	32,864	208,348	241,212
Total average daily production (BOE/day)	14,253	82,608	96,861	16,376	62,752	79,128
Pricing(2)						
Crude oil (per bbl)	$ 69.12	$ 87.42	$ 83.98	$ 48.68	$ 56.38	$ 54.21
Natural gas liquids (per bbl)	45.44	20.47	25.95	33.23	23.69	26.22
Natural gas (per Mcf)	2.78	3.27	3.22	2.50	2.59	2.58
Capital Expenditures						
Capital spending	$ 15.3	$ 178.0	$ 193.3	$ 10.0	$ 109.1	$ 119.1
Acquisitions	0.9	0.8	1.7	0.8	1.4	2.2
Divestments	1.1	(0.3)	0.8	1.3	0.1	1.4
Netback(3) **Before Hedging**						
Oil and natural gas sales	$ 69.4	$ 397.0	$ 466.4	$ 55.0	$ 186.9	$ 241.9
Royalties	(13.4)	(79.4)	(92.8)	(9.2)	(36.6)	(45.8)
Production taxes	(1.1)	(25.5)	(26.6)	(0.7)	(11.6)	(12.3)
Cash operating expenses	(19.1)	(41.5)	(60.6)	(18.0)	(30.9)	(48.9)
Transportation costs	(2.9)	(30.1)	(33.0)	(2.9)	(23.4)	(26.3)
Netback before hedging	$ 32.9	$ 220.5	$ 253.4	$ 24.2	$ 84.4	$ 108.6
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 54.1	$ —	$ 54.1	$ 34.2	$ —	$ 34.2
General and administrative expense(4)	9.9	6.4	16.3	9.2	6.5	15.7
Current income tax expense/(recovery)	(0.4)	0.5	0.1	(0.4)	0.5	0.1

($ millions, except per unit amounts)	Nine months ended September 30, 2018 Canada	U.S.	Total	Nine months ended September 30, 2017 Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	9,297	34,595	43,892	11,217	23,885	35,102
Natural gas liquids (bbls/day)	1,100	3,387	4,487	1,191	2,468	3,659
Natural gas (Mcf/day)	28,891	230,738	259,629	49,247	218,605	267,852
Total average daily production (BOE/day)	15,213	76,438	91,651	20,616	62,787	83,403
Pricing(2)						
Crude oil (per bbl)	$ 62.78	$ 82.83	$ 78.58	$ 50.39	$ 58.27	$ 55.75
Natural gas liquids (per bbl)	46.84	23.00	28.85	36.12	25.70	29.09
Natural gas (per Mcf)	2.67	3.19	3.14	3.37	3.24	3.26
Capital Expenditures						
Capital spending	$ 39.8	$ 482.0	$ 521.8	$ 45.6	$ 295.6	$ 341.2
Acquisitions	3.0	13.4	16.4	3.5	6.0	9.5
Divestments	0.3	(6.3)	(6.0)	(57.5)	(0.1)	(57.6)
Netback(3) **Before Hedging**						
Oil and natural gas sales	$ 197.0	$ 1,004.8	$ 1,201.8	$ 211.4	$ 590.3	$ 801.7
Royalties	(34.2)	(201.6)	(235.8)	(35.4)	(116.7)	(152.1)
Production taxes	(2.6)	(62.8)	(65.4)	(2.6)	(33.9)	(36.5)
Cash operating expenses	(57.3)	(118.0)	(175.3)	(63.9)	(81.5)	(145.4)
Transportation costs	(8.8)	(81.3)	(90.1)	(10.4)	(74.7)	(85.1)
Netback before hedging	$ 94.1	$ 541.1	$ 635.2	$ 99.1	$ 283.5	$ 382.6
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 165.5	$ —	$ 165.5	$ (55.3)	$ —	$ (55.3)
General and administrative expense(4)	31.6	25.1	56.7	35.0	19.6	54.6
Current income tax expense/(recovery)	(0.4)	0.6	0.2	(0.4)	2.6	2.2

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

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2018				
Third Quarter	$ 373.6	$ 86.9	$ 0.35	$ 0.35
Second Quarter	327.4	$ 12.4	$ 0.05	$ 0.05
First Quarter	265.0	29.6	0.12	0.12
Total 2018	$ 966.0	$ 128.9	$ 0.53	$ 0.52
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, increased in the third quarter of 2018 compared to the second quarter of 2018 due to increased production volumes and higher realized crude oil and natural gas prices. Net income increased in the third quarter of 2018 compared to the second quarter of 2018 due to an increase in sales and a decrease in losses from commodity derivative instruments. Oil and natural gas sales, net of royalties, have continued to improve in 2018 compared to 2017 and 2016 due to an increase in realized commodity prices and a higher weighting of crude oil and natural gas liquids as a proportion of total production. Net income has continued to improve in 2018, excluding the effects of a gain which was recorded on asset divestments in the second quarter of 2017 and reversal of valuation allowance on deferred tax asset in the fourth quarter of 2016.

2018 UPDATED GUIDANCE

We are revising our average annual production guidance range to 92,500 – 93,000 BOE/day, the high end of our previous range of 91,000 – 93,000 BOE/day. We are also revising our average annual crude oil and liquids guidance range to 49,500 – 50,000 bbls/day, the high end of our previous range of 49,000 – 50,000 bbls/day and guiding to a fourth quarter average crude oil and liquids production range of 53,500 – 54,500 bbls/day.

We are maintaining our operating cost guidance of $7.00/BOE and reaffirming our annual capital spending guidance of $585 million. With higher annual average production, we are reducing our annual cash G&A guidance to $1.50/BOE from $1.55/BOE.

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

Summary of 2018 Expectations	Target
Capital spending	$585 million
Average annual production	92,500 - 93,000 BOE/day (from 91,000 - 93,000 BOE/day)
Average annual crude oil and natural gas liquids production	49,500 - 50,000 bbls/day (from 49,000 - 50,000 bbls/day)
Fourth quarter average crude oil and natural gas liquids	53,500 - 54,500 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	$1.50/BOE (from $1.55/BOE)

2018 Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.80)/bbl (from US$(3.50)/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 ($ millions)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Oil and natural gas sales	$ 466.4	$ 241.9	$ 1,201.8	$ 801.7
Less:				
Royalties	(92.8)	(45.8)	(235.8)	(152.1)
Production taxes	(26.6)	(12.3)	(65.4)	(36.5)
Cash operating expenses[(1)]	(60.6)	(48.9)	(175.3)	(145.4)
Transportation costs	(33.0)	(26.3)	(90.1)	(85.1)
Netback before hedging	$ 253.4	$ 108.6	$ 635.2	$ 382.6
Cash gains/(losses) on derivative instruments	(23.9)	2.9	(33.0)	11.7
Netback after hedging	$ 229.5	$ 111.5	$ 602.2	$ 394.3

(1) Total operating expenses have been adjusted to exclude a non-cash loss of $0.1 million and nil for the three and nine months ended September 30, 2018, and non-cash gains of $0.1 million and $0.4 million, respectively, for the three and nine months ended September 30, 2017.

"Adjusted funds flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating and financial performance, leverage and liquidity. Adjusted funds flow is calculated as 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 ($ millions)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Cash flow from operating activities	$ 216.1	$ 114.6	$ 517.2	$ 340.8
Asset retirement obligation expenditures	2.8	3.1	8.1	7.1
Changes in non-cash operating working capital	(8.5)	(27.3)	13.9	(23.4)
Adjusted funds flow	$ 210.4	$ 90.4	$ 539.2	$ 324.5

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

"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 ($ millions)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Dividends	$ 7.4	$ 7.3	$ 22.0	$ 21.8
Capital and office expenditures	194.9	119.6	527.1	342.2
Sub-total	$ 202.3	$ 126.9	$ 549.1	$ 364.0
Adjusted funds flow	$ 210.4	$ 90.4	$ 539.2	$ 324.5
Adjusted payout ratio (%)	96%	140%	102%	112%

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

Reconciliation of Net Income to Adjusted EBITDA[(1)]

($ millions)	September 30, 2018
Net income/(loss)	$ 144.2
Add:	
Interest	36.7
Current and deferred tax expense/(recovery)	51.4
DD&A and asset impairment	284.4
Other non-cash charges[(2)]	218.1
Adjusted EBITDA	$ 734.8

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at September 30, 2018 include the nine months ended September 30, 2018 and the fourth quarter of 2017.
(2) Includes the change in fair value of commodity derivatives, fixed price electricity swaps and equity swaps, non-cash SBC expense, and unrealized foreign exchange gains/losses.

In addition, the Company uses certain financial measures within the "Liquidity and Capital Resources" section of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "senior debt to adjusted EBITDA", "senior net debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "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 September 30, 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 July 1, 2018 and ended September 30, 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; our current NCIB and share repurchases thereunder; our future acquisitions and dispositions, expecting timing thereof and use of proceeds therefrom; and the amount of future cash dividends that we may pay to our shareholders.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of *production and/or reduced realized prices beyond our current expectations; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; the availability of third party services; and the extent of our liabilities. In addition, our updated 2018 guidance contained in this MD&A is based on the following forward prices: a WTI price of US$66.86/bbl, a NYMEX price of US$2.96/Mcf, and a USD/CDN exchange rate of 1.29. 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	September 30, 2018	December 31, 2017
Assets			
Current Assets			
Cash and cash equivalents		$ 347,611	$ 346,548
Accounts receivable	4	199,956	129,386
Income tax receivable	13	52,244	1,190
Deferred financial assets	15	—	3,852
Other current assets		4,280	5,902
		604,091	486,878
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	5	1,233,691	889,967
Other capital assets, net	5	12,815	10,064
Property, plant and equipment		1,246,506	900,031
Goodwill		643,911	638,878
Deferred income tax asset	13	549,129	569,937
Income tax receivable	13	—	50,108
Total Assets		$ 3,043,637	$ 2,645,832
Liabilities			
Current liabilities			
Accounts payable	7	$ 332,614	$ 213,978
Dividends payable		2,449	2,421
Current portion of long-term debt	8	58,398	27,656
Deferred financial liabilities	15	111,349	28,642
		504,810	272,697
Deferred financial liabilities	15	54,586	9,907
Long-term debt	8	602,804	644,723
Asset retirement obligation	9	119,411	117,736
		776,801	772,366
Total Liabilities		1,281,611	1,045,063
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: September 30, 2018 – 245 million shares			
December 31, 2017 – 242 million shares	14	3,412,191	3,386,946
Paid-in capital		69,710	75,375
Accumulated deficit		(2,018,614)	(2,124,676)
Accumulated other comprehensive income/(loss)		298,739	263,124
		1,762,026	1,600,769
Total Liabilities & Shareholders' Equity		$ 3,043,637	$ 2,645,832
Contingencies	16		
Subsequent events	8, 14		

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

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

(CDN$ thousands, except per share amounts) unaudited	Note	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Revenues					
Oil and natural gas sales, net of royalties	10	$ 373,577	$ 196,068	$ 965,981	$ 649,579
Commodity derivative instruments gain/(loss)	15	(54,054)	(34,215)	(165,469)	55,295
		319,523	161,853	800,512	704,874
Expenses					
Operating		60,709	48,843	175,349	144,992
Transportation		33,013	26,314	90,057	85,147
Production taxes		26,583	12,330	65,367	36,497
General and administrative	11	16,291	15,741	56,704	54,574
Depletion, depreciation and accretion		81,509	59,758	218,720	185,117
Interest		8,601	8,663	26,953	29,015
Foreign exchange (gain)/loss	12	(7,596)	(17,577)	11,686	(33,585)
Gain on divestment of assets	5	—	—	—	(78,400)
Other expense/(income)		(1,631)	(743)	(4,261)	(1,786)
		217,479	153,329	640,575	421,571
Income/(Loss) before taxes		102,044	8,524	159,937	283,303
Current income tax expense/(recovery)	13	92	84	230	2,198
Deferred income tax expense/(recovery)	13	15,029	(7,691)	30,743	59,379
Net Income/(Loss)		$ 86,923	$ 16,131	$ 128,964	$ 221,726
Other Comprehensive Income/(Loss)					
Change in cumulative translation adjustment		(26,743)	(52,019)	35,615	(98,675)
Total Comprehensive Income/(Loss)		$ 60,180	$ (35,888)	$ 164,579	$ 123,051
Net income/(Loss) per share					
Basic	14	$ 0.35	$ 0.07	$ 0.53	$ 0.92
Diluted	14	$ 0.35	$ 0.07	$ 0.52	$ 0.90

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	Nine months ended September 30, 2018	2017
Share Capital		
Balance, beginning of year	$ 3,386,946	$ 3,365,962
Purchase of common shares under Normal Course Issuer Bid	(7,587)	—
Share-based compensation – settled	23,389	20,984
Stock Option Plan – cash	8,742	—
Stock Option Plan – exercised	701	—
Balance, end of period	$ 3,412,191	$ 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	18,425	15,601
Stock Option Plan – exercised	(701)	—
Balance, end of period	$ 69,710	$ 68,400
Accumulated Deficit		
Balance, beginning of year	$ (2,124,676)	$ (2,332,641)
Purchase of common shares under Normal Course Issuer Bid	(880)	—
Net income/(loss)	128,964	221,726
Dividends declared	(22,022)	(21,769)
Balance, end of period	$ (2,018,614)	$ (2,132,684)
Accumulated Other Comprehensive Income/(Loss)		
Balance, beginning of year	$ 263,124	$ 353,401
Change in cumulative translation adjustment	35,615	(98,675)
Balance, end of period	$ 298,739	$ 254,726
Total Shareholders' Equity	$ 1,762,026	$ 1,577,388

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

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Note	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Operating Activities					
Net income/(loss)		$ 86,923	$ 16,131	$ 128,964	$ 221,726
Non-cash items add/(deduct):					
Depletion, depreciation and accretion		81,509	59,758	218,720	185,117
Changes in fair value of derivative instruments	15	30,403	36,163	131,238	(43,797)
Deferred income tax expense/(recovery)	13	15,029	(7,691)	30,743	59,379
Foreign exchange (gain)/loss on debt and working capital	12	(12,154)	(31,639)	17,881	(48,614)
Share-based compensation	14	4,349	4,171	18,425	15,601
Translation of U.S. dollar cash held in Canada	12	4,292	13,493	(6,750)	13,493
Gain on divestment of assets	5	—	—	—	(78,400)
Asset retirement obligation expenditures	9	(2,757)	(3,060)	(8,141)	(7,124)
Changes in non-cash operating working capital	17	8,504	27,250	(13,915)	23,412
Cash flow from/(used in) operating activities		216,098	114,576	517,165	340,793
Financing Activities					
Dividends	14,17	(7,356)	(7,264)	(21,994)	(21,753)
Bank credit facility		—	—	—	(23,272)
Senior notes	8	—	—	(29,044)	(29,084)
Proceeds from the issuance of shares	14	4,398	—	8,742	—
Purchase of common shares under Normal Course Issuer Bid	14	(8,467)	—	(8,467)	—
Cash flow from/(used in) financing activities		(11,425)	(7,264)	(50,763)	(74,109)
Investing Activities					
Capital and office expenditures	17	(209,072)	(126,226)	(465,182)	(332,490)
Property and land acquisitions		(1,702)	(2,222)	(10,284)	(9,471)
Property divestments		(762)	(1,361)	(56)	57,581
Cash flow from/(used in) investing activities		(211,536)	(129,809)	(475,522)	(284,380)
Effect of exchange rate changes on cash and cash equivalents		(5,948)	(13,514)	10,183	(26,562)
Change in cash and cash equivalents		(12,811)	(36,011)	1,063	(44,258)
Cash and cash equivalents, beginning of period		360,422	385,058	346,548	393,305
Cash and cash equivalents, end of period		**$ 347,611**	**$ 349,047**	**$ 347,611**	**$ 349,047**

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

Notes to Condensed Consolidated Financial Statements
(unaudited)

1) REPORTING ENTITY

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

2) BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under accounting principles generally accepted in the United States of America ("U.S. GAAP") for the three and nine months ended September 30, 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 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 (ROU) asset and related lease liability on the balance sheet for all leases, including operating leases. The FASB further issued several ASUs in 2018 which provide clarification on implementation of the new standard, technical corrections, improvements and practical expedients that can be applied under certain circumstances. 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 using either 1) the effective date or 2) the beginning of the earliest comparative period presented in the financial statements as the Company's date of initial adoption. The Company expects to adopt the new standard on January 1, 2019 and use the effective date as its date of initial application.

The standard also provides for certain practical expedients at the date of adoption and for an entity's ongoing accounting. The Company currently expects to elect the practical expedient pertaining to land easements and the short-term lease recognition exemption which allows it to not recognize ROU assets or lease liabilities for leases with a term shorter than twelve months.

The Company has developed a preliminary inventory of existing lease agreements, and expects that there will be a material impact on its Consolidated Financial Statements. While the Company continues to assess all of the effects of adoption, the most significant effects relate to 1) the recognition of new ROU assets and lease liabilities on the Balance Sheet for office and equipment operating leases and 2) providing significant new disclosures about the Company's leasing activities. The Company continues to address 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)	September 30, 2018	December 31, 2017
Accrued revenue	$ 171,847	$ 102,051
Accounts receivable – trade	32,046	30,787
Allowance for doubtful accounts	(3,937)	(3,452)
Total accounts receivable, net of allowance for doubtful accounts	$ 199,956	$ 129,386

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

As of September 30, 2018 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties	$ 14,316,791	$ (13,083,100)	$ 1,233,691
Other capital assets	113,358	(100,543)	12,815
Total PP&E	$ 14,430,149	$ (13,183,643)	$ 1,246,506

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

There was no gain or loss on asset divestments recorded during the nine months ended September 30, 2018. During the nine months ended September 30, 2017, Enerplus recorded a gain on asset divestments of $78.4 million on the sale of certain Canadian assets for proceeds of $59.3 million, after closing adjustments.

6) ASSET IMPAIRMENT

There was no impairment recorded for the nine months ended September 30, 2018 and 2017.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from September 30, 2017 through September 30, 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
Q3 2018	$ 63.43	1.28	$ 74.38	$ 2.92	$ 1.64
Q2 2018	57.67	1.27	67.77	2.92	1.82
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

7) ACCOUNTS PAYABLE

($ thousands)	September 30, 2018	December 31, 2017
Accrued payables	$ 165,030	$ 96,743
Accounts payable – trade	167,584	117,235
Total accounts payable	$ 332,614	$ 213,978

8) DEBT

($ thousands)	September 30, 2018	December 31, 2017
Current:		
Senior notes	$ 58,398	$ 27,656
Long-term:		
Bank credit facility	—	—
Senior notes	602,804	644,723
Total debt	$ 661,202	$ 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	$ 135,535
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	25,816
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$298,000	384,658
June 18, 2009	June 18 and Dec 18	3 equal annual installments June 18, 2019 - 2021	7.97%	US$225,000	US$66,000	85,193
					Total carrying value	$ 661,202

During the nine months ended September 30, 2018 and 2017, Enerplus made its first and second US$22 million principal repayments on its 2009 senior notes. There were no principal repayments during the three months ended September 30, 2018 and 2017.

Subsequent to the quarter, Enerplus extended its $800 million senior, unsecured bank credit facility to October 31, 2021. There were no other significant amendments to the agreement terms or covenants.

9) ASSET RETIREMENT OBLIGATION

($ thousands)	Nine months ended September 30, 2018	Year ended December 31, 2017
Balance, beginning of year	$ 117,736	$ 181,700
Change in estimates	7,967	13,064
Property acquisitions and development activity	1,271	1,322
Dispositions	(3,920)	(72,306)
Settlements	(8,141)	(12,907)
Accretion expense	4,498	6,863
Balance, end of period	$ 119,411	$ 117,736

Enerplus has estimated the present value of its asset retirement obligation to be $119.4 million at September 30, 2018 based on a total undiscounted liability of $324.5 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 5.66% (December 31, 2017 – 5.73%).

10) OIL AND NATURAL GAS SALES

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2018	2017	2018	2017
Oil and natural gas sales	$ 466,386	$ 241,883	$ 1,201,760	$ 801,718
Royalties[1]	(92,809)	(45,815)	(235,779)	(152,139)
Oil and natural gas sales, net of royalties	$ 373,577	$ 196,068	$ 965,981	$ 649,579

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

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

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

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

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

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 September 30,		Nine months ended September 30,	
($ thousands)	2018	2017	2018	2017
General and administrative expense	$ 12,000	$ 11,685	$ 37,336	$ 37,937
Share-based compensation expense[1]	4,291	4,056	19,368	16,637
General and administrative expense	$ 16,291	$ 15,741	$ 56,704	$ 54,574

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

12) FOREIGN EXCHANGE

($ thousands)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Realized:				
Foreign exchange (gain)/loss	$ 266	$ 569	$ 555	$ 1,536
Translation of U.S. dollar cash held in Canada (gain)/loss	4,292	13,493	(6,750)	13,493
Unrealized:				
Translation of U.S. dollar debt and working capital (gain)/loss	(12,154)	(31,639)	17,881	(48,614)
Foreign exchange (gain)/loss	$ (7,596)	$ (17,577)	$ 11,686	$ (33,585)

13) INCOME TAXES

($ thousands)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Current tax expense/(recovery)				
Canada	$ (400)	$ (400)	$ (400)	$ (400)
United States	492	484	630	2,598
Current tax expense/(recovery)	92	84	230	2,198
Deferred tax expense/(recovery)				
Canada	$ (18,785)	$ (15,241)	$ (44,755)	$ 23,941
United States	33,814	7,550	75,498	35,438
	15,029	(7,691)	30,743	59,379
Income tax expense/(recovery)	$ 15,121	$ (7,607)	$ 30,973	$ 61,577

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 $549.1 million at September 30, 2018 (December 31, 2017 – $569.9 million).

At September 30, 2018, the current income tax receivable included $51.5 million related to a portion of the U.S. Alternative Minimum Tax ("AMT") refund (December 31, 2017 – $50.1 million).

14) SHAREHOLDERS' EQUITY

a) Share Capital

	Nine months ended September 30, 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/(Purchased) for cash:				
Stock Option Plan	640	8,742	—	—
Purchase of common shares under Normal Course Issuer Bid	(544)	(7,587)	—	—
Non-cash:				
Share-based compensation – settled	2,539	23,389	1,646	20,984
Stock Option Plan – exercised	—	701	—	—
Balance, end of period	244,764	$ 3,412,191	242,129	$ 3,386,946

Dividends declared to shareholders for the three and nine months ended September 30, 2018 were $7.4 million and $22.0 million, respectively (2017 – $7.3 million and $21.8 million, respectively).

On March 21, 2018, Enerplus announced the acceptance of its Normal Course Issuer Bid ("NCIB") to repurchase shares through the facilities of the Toronto Stock Exchange, New York Stock Exchange and/or alternative Canadian trading systems. Pursuant to the NCIB, the Company was permitted to repurchase for cancellation up to 17,095,598 common shares over a period of twelve months commencing on March 26, 2018. All repurchases are made in accordance with the NCIB at prevailing market prices plus brokerage fees, with consideration allocated to share capital up to the average carrying amount of the shares, and any excess is allocated to accumulated deficit. During the three months ended September 30, 2018, the Company repurchased 544,300 million common shares under the NCIB at an average price of $15.54 per share, for total consideration of $8.5 million. Of the amount paid, $7.6 million was charged to share capital and $0.9 million was charged to accumulated deficit.

Subsequent to the quarter, the Company repurchased an additional 1,071,366 million common shares under the NCIB at an average price of $15.42 per share.

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):

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2018	2017	2018	2017
Cash:				
Long-term incentive plans (recovery)/expense	$ (211)	$ 712	$ 2,170	$ 852
Non-cash:				
Long-term incentive plans	4,349	4,171	18,425	15,601
Equity swap (gain)/loss	153	(827)	(1,227)	184
Share-based compensation expense	$ 4,291	$ 4,056	$ 19,368	$ 16,637

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

The following table summarizes the Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Deferred Share Unit ("DSU") plan activity for the nine months ended September 30, 2018:

For the nine months ended September 30, 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	77	1,459	805	2,341
Vested	(55)	(1,459)	(1,080)	(2,594)
Forfeited	—	(6)	(50)	(56)
Balance, end of period	390	2,707	1,784	4,881

Cash-settled LTI Plans

For the three and nine months ended September 30, 2018, the Company recorded cash share-based compensation recovery of $0.2 million and expense of $2.2 million, respectively (September 30, 2017 – expense of $0.7 million and $0.9 million, respectively). For the three and nine months ended September 30, 2018 the Company made cash payments of nil and $0.5 million, respectively related to its cash-settled plans (September 30, 2017 – nil and $0.1 million, respectively).

As of September 30, 2018, a liability of $6.2 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 and nine months ended September 30, 2018 the Company recorded non-cash share-based compensation expense of $4.3 million and $18.4 million, respectively (2017 – $4.2 million and $15.6 million, respectively).

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 September 30, 2018 ($ thousands, except for years)	PSU(1)	RSU	Total
Cumulative recognized share-based compensation expense	$ 24,731	$ 10,683	$ 35,414
Unrecognized share-based compensation expense	11,013	7,135	18,148
Fair value	$ 35,744	$ 17,818	$ 53,562
Weighted-average remaining contractual term (years)	1.7	1.4	

(1) Includes estimated performance multipliers.

ii) Stock Option Plan

The Company suspended the issuance of stock options in 2014. At September 30, 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 nine months ended September 30, 2018:

Period ended September 30, 2018	Number of Options (thousands)	Weighted Average Exercise Price
Options outstanding, beginning of year	5,486	$ 18.25
Exercised	(640)	13.66
Forfeited	(42)	22.01
Expired	(638)	30.20
Options outstanding, end of period	4,166	$ 17.09
Options exercisable, end of period	4,166	$ 17.09

At September 30, 2018, Enerplus had 4,166,448 options that were exercisable at a weighted average exercise price of $17.09 with a weighted average remaining contractual term of 1.0 years, giving an aggregate intrinsic value of $5.4 million (September 30, 2017 – 1.8 years and nil). The intrinsic value of options exercised for the three and nine months ended September 30, 2018 was $1.2 million and $1.8 million, respectively (September 30, 2017 – nil and nil, respectively).

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

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

	Three months ended September 30,		Nine months ended September 30,	
(thousands, except per share amounts)	2018	2017	2018	2017
Net income/(loss)	$ 86,923	$ 16,131	$ 128,964	$ 221,726
Weighted average shares outstanding – Basic	245,235	242,129	244,659	241,854
Dilutive impact of share-based compensation	5,722	5,478	5,389	5,452
Weighted average shares outstanding – Diluted	250,957	247,607	250,048	247,306
Net income/(loss) per share				
Basic	$ 0.35	$ 0.07	$ 0.53	$ 0.92
Diluted	$ 0.35	$ 0.07	$ 0.52	$ 0.90

15) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At September 30, 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 September 30, 2018, the senior notes had a carrying value of $661.2 million and a fair value of $659.2 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 and nine months ended September 30, 2018 and 2017:

	Three months ended September 30,		Nine months ended September 30,		Income Statement
Gain/(Loss) ($ thousands)	**2018**	**2017**	**2018**	**2017**	**Presentation**
Electricity Swaps	$ (62)	$ 139	$ —	$ 409	Operating expense
Equity Swaps	(153)	827	1,227	(184)	G&A expense
Commodity Derivative Instruments:					
Oil	(29,977)	(37,465)	(130,737)	34,173	Commodity derivative
Gas	(211)	336	(1,728)	9,399	instruments
Total	$ (30,403)	$ (36,163)	$ (131,238)	$ 43,797	

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

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2018**	**2017**	**2018**	**2017**
Change in fair value gain/(loss)	$ (30,188)	$ (37,129)	$ (132,465)	$ 43,572
Net realized cash gain/(loss)	(23,866)	2,914	(33,004)	11,723
Commodity derivative instruments gain/(loss)	$ (54,054)	$ (34,215)	$ (165,469)	$ 55,295

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

	September 30, 2018		December 31, 2017		
	Liabilities		Assets	Liabilities	
($ thousands)	**Current**	**Long-term**	**Current**	**Current**	**Long-term**
Equity Swaps	$ 892	$ —	$ —	$ 2,119	$ —
Commodity Derivative Instruments:					
Oil	110,439	54,586	2,142	26,523	9,907
Gas	18	—	1,710	—	—
Total	$ 111,349	$ 54,586	$ 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 October 30, 2018:

Crude Oil Instruments:

Instrument Type[(1)(2)]	**bbls/day**	**US$/bbl**
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	17,000	54.12
WTI Sold Call	17,000	64.12
WTI Sold Put	17,000	44.28
WCS Differential Swap (Sale)	1,500	(14.17)
WCS Differential Swap (Purchase)	1,500	(36.12)
Apr 1, 2019 – Jun 30, 2019		
WTI Purchased Put	23,500	54.59
WTI Sold Call	23,500	65.52
WTI Sold Put	23,500	44.50
Jul 1, 2019 – Sep 30, 2019		
WTI Purchased Put	24,500	54.81
WTI Sold Call	24,500	65.95
WTI Sold Put	24,500	44.64
Oct 1, 2019 – Dec 31, 2019		
WTI Purchased Put	24,500	54.81
WTI Sold Call	24,500	65.99
WTI Sold Put	24,500	44.64
Jan 1, 2020 – Dec 31, 2020		
WTI Purchased Put	16,000	57.50
WTI Sold Call	16,000	72.50
WTI Sold Put	16,000	46.88

(1) Transactions with a common term have been aggregated and presented at a weighted average price/bbl before premiums.
(2) The total average deferred premium on three way collars is US$1.60/bbl from October 1, 2018 to December 31, 2020.

Natural Gas Instruments:

Instrument Type(1)	MMcf/day	US$/Mcf
Oct 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.

Enerplus has physical sales contracts in place for approximately 20,250 bbls/day of Bakken production at an average differential of US$2.53/bbl below WTI for the fourth quarter of 2018. In addition, the Company has physical sales contracts in place for approximately 16,000 bbls/day of 2019 Bakken production with fixed differentials averaging approximately US$3.00/bbl below WTI. The Company also has physical sales contracts in place for approximately 15,000 MMBtu/day of Alberta natural gas production at an average differential of US$0.63/Mcf below NYMEX through October 2019.

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations, U.S. dollar denominated senior notes, cash deposits and working capital. Additionally, Enerplus' crude oil sales and a portion of its natural gas sales are based on U.S. dollar indices. To mitigate exposure to fluctuations in foreign exchange, Enerplus may enter into foreign exchange derivatives. At September 30, 2018, Enerplus did not have any foreign exchange derivatives outstanding.

Interest Rate Risk:

At September 30, 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 in 2018 and 2019 that effectively fix the future settlement cost on 195,000 shares at a weighted average price of $20.60 per share.

ii) Credit Risk

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

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

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At September 30, 2018, 83% of Enerplus' marketing receivables were with companies considered investment grade.

Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts of future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectable the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at September 30, 2018 was $3.9 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 September 30, 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 September 30,		Nine months ended September 30,	
($ thousands)	2018	2017	2018	2017
Accounts receivable	$ (21,064)	$ 11,217	$ (72,564)	$ 29,272
Other current assets	(1,537)	(3,406)	1,622	(5,947)
Accounts payable	31,105	19,439	57,027	87
	$ 8,504	$ 27,250	$ (13,915)	$ 23,412

b) Changes in Other Non-Cash Working Capital

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2018	2017	2018	2017
Non-cash financing activities(1)	$ (1)	$ —	$ 28	$ 16
Non-cash investing activities(2)	(14,160)	(6,577)	61,964	9,674

(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 September 30, 2018	2017	Nine months ended September 30, 2018	2017
Income taxes paid/(received)	$ (398)	$ 776	$ (481)	$ 2,715
Interest paid	3,352	2,762	21,545	23,213

BOARD OF DIRECTORS

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Corporate Director
Boerne, 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]
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Calgary, Alberta

Robert B. Hodgins[3][6][9]
Corporate Director
Calgary, Alberta

Susan M. MacKenzie[5][7][12]
Corporate Director
Calgary, Alberta

Glen D. Roane[4][5]
Corporate Director
Canmore, Alberta

Jeffrey W. Sheets[5][9][11]
Corporate Director
Houston, Texas

Sheldon B. Steeves[8][11]
Corporate Director
Calgary, Alberta

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

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas
President & Chief Executive Officer

Raymond J. Daniels
Senior Vice President, Operations, People & Culture

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

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

Nathan D. Fisher
Vice President, U.S. Development & Geosciences

Daniel J. Fitzgerald
Vice President, Business Development

John E. Hoffman
Vice President, Canadian Operations

David A. McCoy
Vice President, General Counsel & Corporate Secretary

Edward L. McLaughlin
President, U.S. Operations

Shaina B. Morihira
Vice President, Finance

CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS CORPORATION

Enerplus Resources (USA) Corporation

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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 at Edmonton, Alberta, the benchmark for Canadian light sweet crude oil pricing
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
TGP Z4 300L	Price benchmark for Marcellus natural gas delivered into the 300 Leg within Zone 4 of the Tennessee Gas Pipeline system between Tioga and Susquehanna Counties in Pennsylvania
Transco Leidy	Price benchmark for Marcellus natural gas delivered into the Transco pipeline system between Hunterdon County, New Jersey and connections east of the Leidy storage facility in Clinton and Potter Counties in Pennsylvania
U.S. GAAP	accounting principles generally accepted in the United States of America
WCS	Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

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