# Q2 2018

# Second Quarter Report

## Six Months Ended June 30, 2018

| SELECTED FINANCIAL RESULTS | Three months ended June 30, 2018 | Three months ended June 30, 2017 | Six months ended June 30, 2018 | Six months ended June 30, 2017 |
|---|---|---|---|---|
| **Financial (000's)** | | | | |
| Net Income/(Loss) | $ 12,404 | $ 129,302 | $ 42,041 | $ 205,595 |
| Adjusted Funds Flow[4] | 173,708 | 114,199 | 328,870 | 234,119 |
| Dividends to Shareholders – Declared | 7,347 | 7,264 | 14,667 | 14,505 |
| Debt Outstanding – net of Cash and Restricted Cash | 311,782 | 308,067 | 311,782 | 308,067 |
| Capital Spending | 177,082 | 101,739 | 328,554 | 222,086 |
| Property and Land Acquisitions | 2,392 | 4,713 | 14,664 | 7,249 |
| Property Divestments | (182) | 59,842 | 6,788 | 58,942 |
| Net Debt to Adjusted Funds Flow Ratio[4] | 0.5x | 0.7x | 0.5x | 0.7x |
| **Financial per Weighted Average Shares Outstanding** | | | | |
| Net Income – Basic | $ 0.05 | $ 0.53 | $ 0.17 | $ 0.85 |
| Net Income – Diluted | 0.05 | 0.52 | 0.17 | 0.83 |
| Weighted Average Number of Shares Outstanding (000's) | 244,862 | 242,127 | 244,369 | 241,710 |
| **Selected Financial Results per BOE[1][2]** | | | | |
| Oil & Natural Gas Sales[3] | $ 48.13 | $ 35.96 | $ 45.65 | $ 36.14 |
| Royalties and Production Taxes | (12.08) | (8.95) | (11.28) | (8.42) |
| Commodity Derivative Instruments | (2.28) | 0.28 | (0.57) | 0.57 |
| Cash Operating Expenses | (7.21) | (5.88) | (7.12) | (6.23) |
| Transportation Costs | (3.56) | (3.72) | (3.54) | (3.80) |
| General and Administrative Expenses | (1.44) | (1.53) | (1.57) | (1.69) |
| Cash Share-Based Compensation | (0.05) | — | (0.16) | (0.01) |
| Interest, Foreign Exchange and Other Expenses | (0.95) | (1.34) | (0.99) | (1.31) |
| Current Income Tax Recovery/(Expense) | (0.01) | (0.26) | (0.01) | (0.14) |
| Adjusted Funds Flow[4] | $ 20.55 | $ 14.56 | $ 20.41 | $ 15.11 |

| SELECTED OPERATING RESULTS | Three months ended June 30, 2018 | Three months ended June 30, 2017 | Six months ended June 30, 2018 | Six months ended June 30, 2017 |
|---|---|---|---|---|
| **Average Daily Production[2]** | | | | |
| Crude Oil (bbls/day) | 45,242 | 36,861 | 41,364 | 35,030 |
| Natural Gas Liquids (bbls/day) | 4,808 | 4,133 | 4,449 | 3,648 |
| Natural Gas (Mcf/day) | 256,995 | 271,292 | 259,141 | 281,393 |
| Total (BOE/day) | 92,883 | 86,209 | 89,003 | 85,577 |
| % Crude Oil and Natural Gas Liquids | 54% | 48% | 51% | 45% |
| **Average Selling Price [2][3]** | | | | |
| Crude Oil (per bbl) | $ 79.98 | $ 55.66 | $ 75.34 | $ 56.54 |
| Natural Gas Liquids (per bbl) | 32.23 | 25.14 | 30.36 | 30.57 |
| Natural Gas (per Mcf) | 2.68 | 3.48 | 3.09 | 3.56 |
| Net Wells Drilled | 18 | 13 | 32 | 28 |

(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 June 30, 2018 | 2017 | Six months ended June 30, 2018 | 2017 |
|---|---|---|---|---|
| WTI crude oil (US$/bbl) | $ 67.88 | $ 48.29 | $ 65.37 | $ 50.10 |
| AECO natural gas – monthly index (CDN$/Mcf) | 1.02 | 2.77 | 1.44 | 2.86 |
| AECO natural gas – daily index (CDN$/Mcf) | 1.18 | 2.78 | 1.63 | 2.74 |
| NYMEX natural gas – last day (US$/Mcf) | 2.80 | 3.18 | 2.90 | 3.25 |
| USD/CDN average exchange rate | 1.29 | 1.34 | 1.28 | 1.33 |

| Share Trading Summary<br>For the three months ended June 30, 2018 | CDN[(1)] - ERF<br>(CDN$) | U.S.[(2)] - ERF<br>(US$) |
|---|---|---|
| High | $ 17.21 | $ 13.49 |
| Low | $ 13.79 | $ 10.75 |
| Close | $ 16.58 | $ 12.60 |

(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 |
| Total Year to Date | $ 0.06 | $ 0.04 |

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

# NEWS RELEASE

**Highlights:**

- Company production of 92,883 BOE per day in the second quarter
- Company liquids production was up 21% quarter-over-quarter, averaging 50,050 barrels per day, achieving the high end of second quarter guidance of 48,000 to 50,000 barrels per day
- 33% production growth in North Dakota quarter-over-quarter
- Increasing 2018 annual production guidance to 91,000 to 93,000 BOE per day, from 86,000 to 91,000 BOE per day
- Revising 2018 annual liquids production guidance to the upper-end of the range, now 49,000 to 50,000 barrels per day, from 46,000 to 50,000 barrels per day
- 2018 capital spending guidance tightened to $585 million (from $535 to $585 million previously) largely related to increased non-operated activity
- Generated adjusted funds flow of $173.7 million during the second quarter
- 2018 adjusted funds flow expected to exceed capital expenditures and dividends by over $100 million based on current forward strip pricing
- Reducing cash G&A guidance by $0.10 per BOE to $1.55 per BOE
- Balance sheet remains among the strongest in the peer group with a net debt to adjusted funds flow ratio of 0.5 times

*"We delivered strong financial and operational performance through the first half of 2018," said Ian C. Dundas, President and Chief Executive Officer. "Our plans to continue to drive profitable growth and competitive returns remain firmly on track. We are increasing our production guidance largely underpinned by high-margin, light oil growth out of the Bakken and we have visibility to generating over $100 million in free cash flow in the second half of the year. Notwithstanding this strong outlook, we will remain disciplined with our capital allocation and continue to focus on creating long-term value for our shareholders."*

**Second Quarter Financial and Operational Summary**

PRODUCTION

Production in the second quarter of 2018 averaged 92,883 BOE per day, up 9% from the first quarter. Liquids production for the quarter averaged 50,050 barrels per day (90% crude oil and 10% natural gas liquids), achieving the high end of second quarter guidance of 48,000 to 50,000 barrels per day. The Company brought 11 operated high working interest wells on production in North Dakota during the quarter, which drove the 21% increase in liquids production from the prior quarter.

Natural gas production for the second quarter averaged 257 MMcf per day, largely flat to the prior quarter.

Enerplus is increasing its 2018 production guidance to 91,000 to 93,000 BOE per day (from 86,000 to 91,000 BOE per day) and annual liquids production guidance is being revised to 49,000 to 50,000 barrels per day, the high-end of the previous range of 46,000 to 50,000 barrels per day. The increased production guidance reflects better than expected well performance in North Dakota along with higher than forecast non-operated production in the Marcellus.

NET INCOME AND ADJUSTED FUNDS FLOW

Enerplus generated net income of $12.4 million in the second quarter of 2018, a decrease from the previous quarter primarily as a result of higher non-cash mark-to-market losses on the Company's commodity derivative instruments resulting from the improvement in forward crude oil prices.

Adjusted funds flow was $173.7 million during the second quarter, up 12% compared to $155.2 million in the previous quarter, supported by an increase of 15% in realized crude oil prices and higher crude oil production during the quarter.

PRICING REALIZATIONS AND COST STRUCTURE

Bakken crude oil differentials continue to see support from improved egress out of the area due to the Dakota Access Pipeline. Enerplus' realized Bakken crude oil price differential averaged US$3.42 per barrel below WTI in the second quarter, in-line with its unchanged 2018 guidance of US$3.50 per barrel below WTI.

The Company's realized Marcellus natural gas price differential was US$0.69 per Mcf below NYMEX in the second quarter. Although weaker than the first quarter due to seasonality and pipeline maintenance issues, Marcellus differentials are expected to improve over the remainder of the year as additional pipeline projects are completed. As a result, the Company's 2018 Marcellus differential guidance of US$0.40 per Mcf below NYMEX is unchanged.

Second quarter operating expenses were $7.20 per BOE, an increase of 3% from the first quarter due to the higher liquids production weighting in the second quarter. Transportation costs of $3.56 per BOE were largely flat to the prior quarter, and second quarter cash general and administrative ("G&A") expenses of $1.44 per BOE were 16% lower compared to the prior quarter largely reflective of higher second quarter production. Enerplus' 2018 guidance for operating costs ($7.00 per BOE) and transportation costs ($3.60 per BOE) remains unchanged. Cash G&A guidance for 2018 is being reduced to $1.55 per BOE (from $1.65 per BOE).

CAPITAL EXPENDITURES AND BALANCE SHEET POSITION

Exploration and development capital spending in the second quarter was $177.1 million associated with drilling 18.2 net wells and completing and bringing on production 12.2 net wells across the Company. Enerplus is tightening its 2018 capital spending guidance to $585 million, from the previous guidance range of $535 to $585 million, as a result of an increase in non-operated activity and modest inflation on the cost of materials and services. Capital spending for the second half of 2018 is expected to be weighted to the third quarter.

Total debt net of cash at June 30, 2018 was $311.8 million. Total debt was comprised of $672.2 million of senior notes outstanding. The Company was undrawn on its $800 million bank credit facility and had a cash balance of $360.4 million. At June 30, 2018, Enerplus' net debt to adjusted funds flow ratio was 0.5 times.

**Average Daily Production(1)**

| | Three months ended June 30, 2018 | | | | Six months ended June 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 | 35.8 | 3.7 | 25.3 | 43.7 | 31.7 | 3.3 | 22.6 | 38.8 |
| Marcellus | — | — | 202.4 | 33.7 | — | — | 205.4 | 34.2 |
| Canadian Waterfloods | 9.0 | 0.1 | 3.8 | 9.8 | 9.2 | 0.1 | 4.4 | 10.1 |
| Other(2) | 0.5 | 0.9 | 25.4 | 5.6 | 0.4 | 1.0 | 26.8 | 5.9 |
| **Total** | **45.2** | **4.8** | **257.0** | **92.9** | **41.4** | **4.4** | **259.1** | **89.0** |

(1) Table may not add due to rounding.
(2) Six months ended June 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 June 30, 2018 | | | | Six months ended June 30, 2018 | | | |
|---|---|---|---|---|---|---|---|---|
| | **Operated** | | **Non Operated** | | **Operated** | | **Non Operated** | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Williston Basin | 11.0 | 10.3 | 2.0 | 0.7 | 19.0 | 15.5 | 2.0 | 0.7 |
| Marcellus | — | — | 14.0 | 1.8 | — | — | 25.0 | 3.3 |
| Canadian Waterfloods | — | — | — | — | 2.0 | 1.9 | — | — |
| Other | — | — | — | — | — | — | 1.0 | 0.3 |
| **Total** | **11.0** | **10.3** | **16.0** | **2.4** | **21.0** | **17.4** | **28.0** | **4.2** |

(1) Table may not add due to rounding.

**Asset Activity**

WILLISTON BASIN

Williston Basin production averaged 43,741 BOE per day (82% oil) during the second quarter of 2018, up 29% from the first quarter of 2018. Second quarter Williston Basin production was comprised of 40,479 BOE per day in North Dakota, a 33% increase from the first quarter, and 3,262 BOE per day in Montana.

Enerplus brought on-stream 11 gross operated wells (94% average working interest) across two pads at Fort Berthold during the second quarter. The six-well Cats pad had an average completed lateral length of 9,700 feet per well and average peak 30-day production rates per well of 2,013 BOE per day (84% oil, on a three-stream basis). The five-well Metals North pad had an average completed lateral length of 8,700 feet per well (including one 4,200 foot lateral) and average peak 30-day production rates per well of 1,684 BOE per day (81% oil, on a three-stream basis).

The Company drilled 13 gross operated wells (92% average working interest) in the second quarter.

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

MARCELLUS

Marcellus production averaged 202 MMcf per day during the second quarter, a decrease from the previous quarter of 3% primarily due to pipeline maintenance and seasonally weaker natural gas prices in the second quarter.

Fourteen gross non-operated wells (13% average working interest) were brought on-stream during the quarter. Thirteen wells had more than 30 days on production as of the date of this news release with an average completed lateral length of 5,300 feet per well and average peak 30-day production rates per well of 8.1 MMcf per day.

The Company participated in drilling 16 gross non-operated wells (13% average working interest) during the second quarter.

CANADIAN WATERFLOODS

Canadian waterflood production averaged 9,770 BOE per day (92% oil) during the second quarter, 5% lower than the previous quarter, primarily due to downtime associated with facility upgrades at Giltedge. Capital activity for the remainder of the year will be focused on the Company's drilling program at Medicine Hat.

DJ BASIN

Enerplus drilled four gross (3.2 net) wells in the DJ Basin during the second quarter. The wells were recently completed and have commenced flow back. Post-cleanout well results are not expected until later this year.

**2018 Guidance**

Enerplus' 2018 updated guidance is summarized below. The Company increased its total production guidance, revised its liquids production and capital guidance, and reduced its cash G&A expense guidance. All other guidance remains unchanged.

| | **Guidance** |
|---|---|
| Capital spending | \$585 million (from \$535 – \$585 million) |
| Average annual production | 91,000 – 93,000 BOE/day (from 86,000 – 91,000 BOE/day) |
| Average annual crude oil and natural gas liquids production | 49,000 – 50,000 bbls/day (from 46,000 – 50,000 bbls/day) |
| Average royalty and production tax rate | 25% |
| Operating expense | \$7.00/BOE |
| Transportation expense | \$3.60/BOE |
| Cash G&A expense | \$1.55/BOE (from \$1.65/BOE) |

| **2018 Full-Year Differential/Basis Outlook**[(1)] | |
|---|---|
| Average U.S. Bakken crude oil differential (compared to WTI crude oil) | US\$(3.50)/bbl |
| 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 22,000 barrels per day of crude oil protected for the remainder of 2018 (approximately 66% of forecast crude oil production at the midpoint of guidance, net of royalties and production taxes), 23,140 barrels per day protected in 2019, and 14,000 barrels per day protected in 2020.

For natural gas, Enerplus has 36,685 Mcf per day protected for the remainder of 2018 (approximately 19% of forecast natural gas production at the midpoint of guidance, net of royalties and production taxes) using collar structures.

## Commodity Hedging Detail (As at August 9, 2018)

| | WTI Crude Oil (US$/bbl)[1] | | | | | | | NYMEX Natural Gas (US$/Mcf)[1] | |
|---|---|---|---|---|---|---|---|---|---|
| | Jul 1, 2018 – Sep 30, 2018 | 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 | Jul 1, 2018 – Oct 31, 2018 | Nov 1, 2018 – Dec 31, 2018 |
| **Swaps** | | | | | | | | | |
| Sold Swaps | $ 53.73 | $ 53.73 | $ 53.73 | — | — | — | — | — | — |
| Volume (bbls/d or Mcf/d) | 3,000 | 3,000 | 3,000 | — | — | — | — | — | — |
| **Three Way Collars[2]** | | | | | | | | | |
| Sold Puts | $ 42.71 | $ 42.74 | $ 44.28 | $ 44.50 | $ 44.64 | $ 44.64 | $ 46.71 | — | — |
| Volume (bbls/d or Mcf/d) | 18,000 | 20,000 | 17,000 | 23,500 | 24,500 | 24,500 | 14,000 | — | — |
| Purchased Puts | $ 52.53 | $ 52.48 | $ 54.12 | $ 54.59 | $ 54.81 | $ 54.81 | $ 57.14 | $ 2.75 | $ 2.75 |
| Volume (bbls/d or Mcf/d) | 18,000 | 20,000 | 17,000 | 23,500 | 24,500 | 24,500 | 14,000 | 40,000 | 30,000 |
| Sold Calls | $ 61.22 | $ 61.10 | $ 64.12 | $ 65.52 | $ 65.95 | $ 65.99 | $ 72.07 | $ 3.38 | $ 3.47 |
| Volume (bbls/d or Mcf/d) | 18,000 | 20,000 | 17,000 | 23,500 | 24,500 | 24,500 | 14,000 | 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$1.59/bbl from July 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.*

*The forward-looking information contained in this news release reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that Enerplus will conduct its operations and achieve results of operations as anticipated; that Enerplus' development plans will achieve the expected results; current commodity price and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of Enerplus' reserves and resources volumes; the continued availability of adequate debt and/or equity financing, cash flow and other sources to fund Enerplus' capital and operating requirements, and dividend payments, as needed; availability of third party services; and the extent of its liabilities. In addition, our 2018 guidance contained in this news release is based on the following forward prices: WTI US$66.00/bbl, NYMEX*

*US$2.84/Mcf, and a USD/CDN exchange rate of 1.30. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.*

*The forward-looking information included in this news release is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: changes, including continued volatility, in commodity prices; changes in realized prices for Enerplus' products; changes in the demand for or supply of Enerplus' products; unanticipated operating results, results from Enerplus' capital spending activities or production declines; curtailment of Enerplus' production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans by Enerplus or by third party operators of Enerplus' properties; increased debt levels or debt service requirements; Enerplus' inability to comply with covenants under its bank credit facility and senior notes; changes in estimates of Enerplus' oil and gas reserves and resources volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners; failure to complete any anticipated acquisitions or divestitures; and certain other risks detailed from time to time in Enerplus' public disclosure documents (including, without limitation, those risks identified in its Annual Information Form, management's discussion and analysis for the year-ended December 31, 2017, and Form 40-F at December 31, 2017).*

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

***NON-GAAP MEASURES***

*In this news release, we use the terms "adjusted funds flow", "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. Calculation of these terms is described in Enerplus' MD&A under the "Liquidity and Capital Resources" section.*

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

Electronic copies of Enerplus Corporation's Second 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 August 9, 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 six months ended June 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 second quarter averaged 92,883 BOE/day, a 9% increase compared to the first quarter of 2018. Our crude oil and natural gas liquids production increased by 21% to 50,050 bbls/day from 41,528 bbls/day in the first quarter of 2018, coming in at the top end of our second quarter crude oil and natural gas liquids production range of 48,000 – 50,000 bbls/day. The increase in production is due to strong well performance in North Dakota with 11.0 net wells brought on-stream during the period, as well as less downtime related to offset completions on adjacent properties when compared to the first quarter of 2018. As a result of outperformance in North Dakota and higher non-operated production in the Marcellus, we are increasing our average annual production range to 91,000 – 93,000 BOE/day (from 86,000 – 91,000 BOE/day) and narrowing our average annual crude oil and liquids guidance range to 49,000 – 50,000 bbls/day (from 46,000 – 50,000 bbls/day).

Our capital spending for the second quarter totaled $177.1 million, with the majority directed to our North Dakota crude oil properties. We are revising our annual capital spending guidance to $585 million (previous guidance range of $535 – $585 million), due to non-operated capital in both North Dakota and the Marcellus, as well as modest cost increases on a portion of our materials and services.

Operating costs for the quarter increased to $60.9 million or $7.20/BOE from $53.8 million or $7.02/BOE in the first quarter of 2018. The increase in operating costs from the first quarter of 2018 was mainly due to a higher crude oil and liquids production weighting in the second quarter with higher per BOE operating costs, along with water handling rate increases. We are maintaining our annual operating cost guidance of $7.00/BOE.

Cash G&A expenses for the second quarter were $12.1 million or $1.44/BOE, a decrease of 16% on a per BOE basis from $1.72/BOE in the first quarter of 2018. Cash G&A expenses per BOE decreased from the first quarter with higher production during the period. We are lowering our annual guidance target for cash G&A expenses to $1.55/BOE from $1.65/BOE.

We continued to add to our commodity hedge positions during the quarter. As of August 9, 2018, we had approximately 66% of our forecasted crude oil production, net of royalties, hedged for the remainder of 2018, and approximately 69% and 42% 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 19% of our forecasted natural gas production, net of royalties, for the remainder of 2018.

We recorded net income of $12.4 million and adjusted funds flow of $173.7 million in the second quarter of 2018, compared to $29.6 million and $155.2 million, respectively, in the first quarter of 2018. Net income in the second quarter was impacted by non-cash mark-to-market losses recorded on our commodity derivative instruments, offset by higher realized commodity prices and production.

At June 30, 2018, our total debt net of cash was $311.8 million and our net debt to adjusted funds flow ratio was 0.5x.

## RESULTS OF OPERATIONS

### Production

Production for the second quarter averaged 92,883 BOE/day, an increase of 7,803 BOE/day or 9% compared to the first quarter of 2018. Crude oil and natural gas liquids production increased by 21%, primarily due to higher North Dakota volumes. The increase was due to the strong well performance of the 11.0 net wells coming on-stream during the second quarter, as well as less downtime from completions activities occurring on adjacent properties.

For the three and six months ended June 30, 2018, crude oil and liquids production increased by 9,056 bbls/day or 22% and 7,135 bbls/day or 18%, respectively, compared to the same periods in 2017. Production increased primarily due to higher spending in North Dakota where we had 16.2 net wells come on-stream year-to-date. This increase was offset somewhat by the impact of 2017 Canadian crude oil asset divestments. Natural gas production decreased by 5% and 8% over the same respective periods due to non-core Canadian asset divestments in the first half of 2017.

Our crude oil and natural gas liquids weighting increased to 54% in the second quarter of 2018, from 48% for the same period of 2017, due to increased capital spending on our North Dakota crude oil asset and the divestment of non-core Canadian natural gas weighted properties.

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

| | Three months ended June 30, | | | Six months ended June 30, | | |
|---|---|---|---|---|---|---|
| **Average Daily Production Volumes** | **2018** | **2017** | **% Change** | **2018** | **2017** | **% Change** |
| Crude oil (bbls/day) | 45,242 | 36,861 | 23% | 41,364 | 35,030 | 18% |
| Natural gas liquids (bbls/day) | 4,808 | 4,133 | 16% | 4,449 | 3,648 | 22% |
| Natural gas (Mcf/day) | 256,995 | 271,292 | (5%) | 259,141 | 281,393 | (8%) |
| Total daily sales (BOE/day) | 92,883 | 86,209 | 8% | 89,003 | 85,577 | 4% |

Based on strong performance in North Dakota and higher non-operated production in the Marcellus, we are increasing our average annual production guidance range to 91,000 – 93,000 BOE/day (from 86,000 – 91,000 BOE/day) and narrowing our average annual crude oil and liquids guidance range to 49,000 – 50,000 bbls/day (from 46,000 – 50,000 bbls/day).

## Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, adjusted funds flow and financial condition. The following table compares quarterly average prices from the first half of 2018 to the first half of 2017 and other periods indicated:

| | Six months ended June 30, | | | | | | |
|---|---|---|---|---|---|---|---|
| **Pricing** (average for the period) | **2018** | **2017** | **Q2 2018** | **Q1 2018** | **Q4 2017** | **Q3 2017** | **Q2 2017** |
| **Benchmarks** | | | | | | | |
| WTI crude oil (US$/bbl) | $ 65.37 | $ 50.10 | $ 67.88 | $ 62.87 | $ 55.40 | $ 48.20 | $ 48.29 |
| AECO natural gas – monthly index ($/Mcf) | 1.44 | 2.86 | 1.02 | 1.85 | 1.96 | 2.04 | 2.77 |
| AECO natural gas – daily index ($/Mcf) | 1.63 | 2.74 | 1.18 | 2.08 | 1.69 | 1.45 | 2.78 |
| NYMEX natural gas – last day (US$/Mcf) | 2.90 | 3.25 | 2.80 | 3.00 | 2.93 | 3.00 | 3.18 |
| USD/CDN average exchange rate | 1.28 | 1.33 | 1.29 | 1.26 | 1.27 | 1.25 | 1.34 |
| USD/CDN period end exchange rate | 1.31 | 1.30 | 1.31 | 1.29 | 1.26 | 1.25 | 1.30 |
| **Enerplus selling price**(1) | | | | | | | |
| Crude oil ($/bbl) | $ 75.34 | $ 56.54 | $ 79.98 | $ 69.67 | $ 65.91 | $ 54.21 | $ 55.66 |
| Natural gas liquids ($/bbl) | 30.36 | 30.57 | 32.23 | 28.13 | 32.26 | 26.22 | 25.14 |
| Natural gas ($/Mcf) | 3.09 | 3.56 | 2.68 | 3.50 | 3.03 | 2.58 | 3.48 |
| **Average differentials** | | | | | | | |
| MSW Edmonton – WTI (US$/bbl) | $ (5.67) | $ (2.90) | $ (5.45) | $ (5.89) | $ (1.14) | $ (2.89) | $ (2.26) |
| WCS Hardisty – WTI (US$/bbl) | (21.78) | (12.85) | (19.27) | (24.28) | (12.27) | (9.94) | (11.13) |
| Transco Leidy monthly – NYMEX (US$/Mcf) | (0.79) | (0.61) | (0.91) | (0.67) | (1.32) | (1.29) | (0.60) |
| TGP Z4 300L monthly – NYMEX (US$/Mcf) | (0.88) | (0.68) | (0.99) | (0.76) | (1.40) | (1.36) | (0.66) |
| AECO monthly – NYMEX (US$/Mcf) | (1.72) | (1.12) | (2.00) | (1.44) | (1.40) | (1.39) | (1.13) |
| **Enerplus realized differentials**(1)(2) | | | | | | | |
| Canada crude oil – WTI (US$/bbl) | $ (18.52) | $ (11.95) | $ (16.31) | $ (20.82) | $ (10.47) | $ (9.29) | $ (11.02) |
| Canada natural gas – NYMEX (US$/Mcf) | (0.84) | (0.56) | (1.18) | (0.52) | (0.56) | (1.00) | (0.51) |
| Bakken crude oil – WTI (US$/bbl) | (3.34) | (5.49) | (3.42) | (3.27) | (1.61) | (3.24) | (5.43) |
| Marcellus natural gas – NYMEX (US$/Mcf) | (0.45) | (0.62) | (0.69) | (0.21) | (0.81) | (1.02) | (0.64) |

(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 second quarter of 2018 increased by 15%, compared to the first quarter of 2018, to average $79.98/bbl. Benchmark WTI crude oil prices increased by 8% comparatively, based on a continued reduction in global crude oil inventories and concerns over the Organization of the Petroleum Exporting Countries ("OPEC") production outlook, particularly in Venezuela and Iran. A weaker Canadian dollar and stronger Canadian crude oil differentials also contributed to the overall realized price increase.

Our realized Bakken price differential to WTI increased by US$0.15/bbl during the quarter to average US$3.42/bbl below WTI, in line with our annual guidance of US$3.50/bbl. Bakken crude oil differentials continue to benefit from improved egress out of the area due to the Dakota Access Pipeline, which has a direct link to the U.S. Gulf Coast, and significant rail takeaway capacity to the U.S. East, West, and Gulf coasts. We continue to expect our annual Bakken crude oil differential to average US$3.50/bbl below WTI.

Our realized price differential for our Canadian crude oil production decreased in the second quarter of 2018 by US$4.51/bbl compared to the previous quarter. Canadian crude oil prices improved during the quarter as pipeline apportionment concerns subsided primarily due to an increase in rail takeaway capacity. Our realized price for natural gas liquids averaged $32.23/bbl during the second quarter, which represents a 15% increase compared to the first quarter of 2018, and is consistent with the increase in benchmark prices.

### NATURAL GAS

Our average realized natural gas price during the second quarter of 2018 decreased by 23% compared to the first quarter of 2018, to average $2.68/Mcf. The decrease was due to a reduction in benchmark NYMEX and regional pricing. Our realized Marcellus sales price differential, excluding transportation and gathering costs, weakened considerably compared to the first quarter, to average US$0.69/Mcf below NYMEX. This weakness was mainly due to pipeline maintenance issues in the region as well as seasonal factors after experiencing very strong prices in the first quarter due to a colder than expected winter. We continue to expect an improvement in Marcellus differentials going forward as more pipeline projects are completed and brought into service during the second half of 2018. We are maintaining our annual guidance of US$0.40/Mcf below NYMEX.

Benchmark AECO gas prices continue to remain weak due to transportation constraints out of the basin. Our realized Canadian natural gas price differential averaged US$1.18/Mcf below NYMEX. We continue to benefit from our multi-year term AECO physical sales contracts, which have an average fixed basis differential of US$0.63/Mcf below NYMEX.

FOREIGN EXCHANGE

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 relative to the U.S. dollar impacts both our revenue as well as our U.S. denominated costs. The stronger Canadian dollar decreases the amount of our realized sales, as well as the amount of our U.S. dollar 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 six months of 2018 with an average exchange rate of 1.28 USD/CDN compared to 1.33 USD/CDN for the same period in 2017. However, when compared to the first quarter of 2018, and the exchange rate at December 31, 2017, 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, as well as other U.S policies related to trade and 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 August 9, 2018, we have hedged approximately 22,000 bbls/day of our expected crude oil production for the remainder of 2018, which represents approximately 66% of our forecasted crude oil production, after royalties. For 2019, we are hedged on approximately 23,140 bbls/day, which represents approximately 69% of our 2018 forecasted crude oil production, after royalties. For 2020, we have hedged 14,000 bbls/day, which represents 42% 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 August 9, 2018, we have hedged approximately 36,685 Mcf/day of our forecasted natural gas production for the remainder of 2018. This represents approximately 19% of our forecasted natural gas production, after royalties.

The following is a summary of our financial contracts in place at August 9, 2018, expressed as a percentage of our forecasted 2018 net production volumes:

| | WTI Crude Oil (US$/bbl)(1) | | | | | | |
|---|---|---|---|---|---|---|---|
| | **Jul 1, 2018 – Sep 30, 2018** | **Oct 1, 2018 – Dec 31, 2018** | **Jan 1, 2019 – Mar 31, 2019** | **Apr 1, 2019 – Jun 30, 2019** | **Jul 1, 2019 – Sep 30, 2019** | **Oct 1, 2019 – Dec 31, 2019** | **Jan 1, 2020 – Dec 31, 2020** |
| **Swaps** | | | | | | | |
| Sold Swaps | $ 53.73 | $ 53.73 | $ 53.73 | — | — | — | — |
| % | 9% | 9% | 9% | — | — | — | — |
| **Three Way Collars(2)** | | | | | | | |
| Sold Puts | $ 42.71 | $ 42.74 | $ 44.28 | $ 44.50 | $ 44.64 | $ 44.64 | $ 46.71 |
| % | 54% | 60% | 51% | 70% | 73% | 73% | 42% |
| Purchased Puts | $ 52.53 | $ 52.48 | $ 54.12 | $ 54.59 | $ 54.81 | $ 54.81 | $ 57.14 |
| % | 54% | 60% | 51% | 70% | 73% | 73% | 42% |
| Sold Calls | $ 61.22 | $ 61.10 | $ 64.12 | $ 65.52 | $ 65.95 | $ 65.99 | $ 72.07 |
| % | 54% | 60% | 51% | 70% | 73% | 73% | 42% |

(1) Based on weighted average price (before premiums) assuming average annual production of 92,000 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$1.59/bbl from July 1, 2018 to December 31, 2020.

| | NYMEX Natural Gas (US$/Mcf)[1] | |
|---|---|---|
| | Jul 1, 2018 – Oct 31, 2018 | Nov 1, 2018 – Dec 31, 2018 |
| **Collars** | | |
| Purchased Puts | $ 2.75 | $ 2.75 |
| % | 21% | 16% |
| Sold Calls | $ 3.38 | $ 3.47 |
| % | 21% | 16% |

(1) Based on weighted average price assuming average annual production of 92,000 BOE/day, which is the mid-point of our updated annual 2018 guidance, less royalties and production taxes of 25%.

## ACCOUNTING FOR PRICE RISK MANAGEMENT

| **Commodity Risk Management Gains/(Losses)** | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions) | 2018 | 2017 | 2018 | 2017 |
| Cash gains/(losses): | | | | |
| Crude oil | $ (20.1) | $ 2.2 | $ (26.4) | $ 1.3 |
| Natural gas | 0.8 | — | 17.3 | 7.5 |
| Total cash gains/(losses) | $ (19.3) | $ 2.2 | $ (9.1) | $ 8.8 |
| Non-cash gains/(losses): | | | | |
| Crude oil | $ (70.9) | $ 27.3 | $ (100.8) | $ 71.6 |
| Natural gas | (0.8) | 2.4 | (1.5) | 9.1 |
| Total non-cash gains/(losses) | $ (71.7) | $ 29.7 | $ (102.3) | $ 80.7 |
| Total gains/(losses) | $ (91.0) | $ 31.9 | $ (111.4) | $ 89.5 |

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| (Per BOE) | 2018 | 2017 | 2018 | 2017 |
| Total cash gains/(losses) | $ (2.28) | $ 0.28 | $ (0.57) | $ 0.57 |
| Total non-cash gains/(losses) | (8.48) | 3.79 | (6.35) | 5.21 |
| Total gains/(losses) | $ (10.76) | $ 4.07 | $ (6.92) | $ 5.78 |

During the second quarter of 2018, we realized cash losses of $20.1 million on our crude oil contracts and cash gains of $0.8 million on our natural gas contracts. In comparison, during the second quarter of 2017, we realized cash gains of $2.2 million on our crude oil contracts. Cash losses on 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 second quarter of 2018, the fair value of our crude oil contracts was in a net liability position of $135.0 million, while the fair value of our natural gas contracts was in a net asset position of $0.2 million. For the three and six months ended June 30, 2018, the change in the fair value of our crude oil contracts represented losses of $70.9 million and $100.8 million, respectively, and our natural gas contracts represented losses of $0.8 million and $1.5 million, respectively.

### Revenues

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions) | 2018 | 2017 | 2018 | 2017 |
| Oil and natural gas sales | $ 406.8 | $ 282.1 | $ 735.3 | $ 559.8 |
| Royalties | (79.4) | (56.4) | (142.9) | (106.3) |
| Oil and natural gas sales, net of royalties | $ 327.4 | $ 225.7 | $ 592.4 | $ 453.5 |

Oil and natural gas sales, net of royalties for the three and six months ended June 30, 2018, were $327.4 million and $592.4 million, respectively, an increase of 45% and 31% from the same periods in 2017. The increase in revenue was a result of the improvement in crude oil prices in the period, along with a higher crude oil and natural gas liquids weighting compared to the prior year.

## Royalties and Production Taxes

| ($ millions, except per BOE amounts) | Three months ended June 30, 2018 | 2017 | Six months ended June 30, 2018 | 2017 |
|---|---|---|---|---|
| Royalties | $ 79.4 | $ 56.4 | $ 142.9 | $ 106.3 |
| Per BOE | $ 9.40 | $ 7.19 | $ 8.87 | $ 6.86 |
| Production taxes | $ 22.6 | $ 13.8 | $ 38.8 | $ 24.2 |
| Per BOE | $ 2.68 | $ 1.76 | $ 2.41 | $ 1.56 |
| Royalties and production taxes | $ 102.0 | $ 70.2 | $ 181.7 | $ 130.5 |
| Per BOE | $ 12.08 | $ 8.95 | $ 11.28 | $ 8.42 |
| Royalties and production taxes (% of oil and natural gas sales) | 25% | 25% | 25% | 23% |

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 less sensitive to commodity price levels. During the three and six months ended June 30, 2018, royalties and production taxes increased to $102.0 million and $181.7 million, respectively, from $70.2 million and $130.5 million for the same periods in 2017 primarily due to higher crude oil sales. In the second quarter of 2018, royalties and production taxes averaged 25%, consistent with the same period in 2017.

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 June 30, 2018 | 2017 | Six months ended June 30, 2018 | 2017 |
|---|---|---|---|---|
| Cash operating expenses | $ 61.0 | $ 46.2 | $ 114.7 | $ 96.4 |
| Non-cash (gains)/losses(1) | (0.1) | (0.4) | (0.1) | (0.3) |
| Total operating expenses | $ 60.9 | $ 45.8 | $ 114.6 | $ 96.1 |
| Per BOE | $ 7.20 | $ 5.83 | $ 7.12 | $ 6.21 |

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

For the three and six months ended June 30, 2018, operating expenses were $60.9 million ($7.20/BOE) and $114.6 million ($7.12/BOE) respectively, compared to our annual guidance of $7.00/BOE. Operating costs increased from $45.8 million ($5.83/BOE) and $96.1 million ($6.21/BOE), respectively, in the same periods in 2017. The increases were due to a higher weighting of U.S. crude oil and liquids production with higher associated per BOE costs, including higher 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 June 30, 2018 | 2017 | Six months ended June 30, 2018 | 2017 |
|---|---|---|---|---|
| Transportation costs | $ 30.1 | $ 29.2 | $ 57.0 | $ 58.8 |
| Per BOE | $ 3.56 | $ 3.72 | $ 3.54 | $ 3.80 |

For the three and six months ended June 30, 2018, transportation costs were $30.1 million ($3.56/BOE) and $57.0 million ($3.54/BOE) respectively, compared to our guidance of $3.60/BOE. During the same periods in 2017, transportation costs were $29.2 million ($3.72/BOE) and $58.8 million ($3.80/BOE), respectively. The decrease in costs on a per BOE basis for the three and six months ended June 30, 2018 was primarily due to a strengthening Canadian dollar.

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 June 30, 2018 Crude Oil | Natural Gas | Total |
|---|---|---|---|
| Average Daily Production | 53,624 BOE/day | 235,554 Mcfe/day | 92,883 BOE/day |
| Netback[1] $ per BOE or Mcfe | (per BOE) | (per Mcfe) | (per BOE) |
| Oil and natural gas sales | $ 71.65 | $ 2.67 | $ 48.13 |
| Royalties and production taxes | (18.66) | (0.51) | (12.08) |
| Cash operating expenses | (10.95) | (0.35) | (7.21) |
| Transportation costs | (2.41) | (0.86) | (3.56) |
| Netback before hedging | $ 39.63 | $ 0.95 | $ 25.28 |
| Cash hedging gains/(losses) | (4.12) | 0.04 | (2.28) |
| Netback after hedging | $ 35.51 | $ 0.99 | $ 23.00 |
| Netback before hedging ($ millions) | $ 193.4 | $ 20.3 | $ 213.7 |
| Netback after hedging ($ millions) | $ 173.3 | $ 21.1 | $ 194.4 |

| Netbacks by Property Type | Three months ended June 30, 2017 Crude Oil | Natural Gas | Total |
|---|---|---|---|
| Average Daily Production | 44,678 BOE/day | 249,180 Mcfe/day | 86,209 BOE/day |
| Netback[1] $ per BOE or Mcfe | (per BOE) | (per Mcfe) | (per BOE) |
| Oil and natural gas sales | $ 50.22 | $ 3.44 | $ 35.96 |
| Royalties and production taxes | (13.82) | (0.62) | (8.95) |
| Cash operating expenses | (10.06) | (0.23) | (5.88) |
| Transportation costs | (2.35) | (0.87) | (3.72) |
| Netback before hedging | $ 23.99 | $ 1.72 | $ 17.41 |
| Cash hedging gains/(losses) | 0.55 | — | 0.28 |
| Netback after hedging | $ 24.54 | $ 1.72 | $ 17.69 |
| Netback before hedging ($ millions) | $ 97.5 | $ 39.0 | $ 136.5 |
| Netback after hedging ($ millions) | $ 99.7 | $ 39.0 | $ 138.7 |

| Netbacks by Property Type | Six months ended June 30, 2018 Crude Oil | Natural Gas | Total |
|---|---|---|---|
| Average Daily Production | 48,890 BOE/day | 240,678 Mcfe/day | 89,003 BOE/day |
| Netback[1] $ per BOE or Mcfe | (per BOE) | (per Mcfe) | (per BOE) |
| Oil and natural gas sales | $ 67.73 | $ 3.12 | $ 45.65 |
| Royalties and production taxes | (17.67) | (0.58) | (11.28) |
| Cash operating expenses | (10.87) | (0.42) | (7.12) |
| Transportation costs | (2.26) | (0.86) | (3.54) |
| Netback before hedging | $ 36.93 | $ 1.26 | $ 23.71 |
| Cash hedging gains/(losses) | (2.99) | 0.40 | (0.57) |
| Netback after hedging | $ 33.94 | $ 1.66 | $ 23.14 |
| Netback before hedging ($ millions) | $ 326.8 | $ 55.1 | $ 381.9 |
| Netback after hedging ($ millions) | $ 300.4 | $ 72.4 | $ 372.8 |

| Netbacks by Property Type | Six months ended June 30, 2017 Crude Oil | Natural Gas | Total |
|---|---|---|---|
| Average Daily Production | 42,546 BOE/day | 258,180 Mcfe/day | 85,577 BOE/day |
| Netback[1] $ per BOE or Mcfe | (per BOE) | (per Mcfe) | (per BOE) |
| Oil and natural gas sales | $ 51.21 | $ 3.54 | $ 36.14 |
| Royalties and production taxes | (13.24) | (0.61) | (8.42) |
| Cash operating expenses | (10.16) | (0.39) | (6.23) |
| Transportation costs | (2.42) | (0.86) | (3.80) |
| Netback before hedging | $ 25.39 | $ 1.68 | $ 17.69 |
| Cash hedging gains/(losses) | 0.17 | 0.16 | 0.57 |
| Netback after hedging | $ 25.56 | $ 1.84 | $ 18.26 |
| Netback before hedging ($ millions) | $ 195.6 | $ 78.5 | $ 274.1 |
| Netback after hedging ($ millions) | $ 196.8 | $ 86.1 | $ 282.9 |

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

Crude oil netbacks per BOE before hedging were higher for the three and six months ended June 30, 2018, compared to the same periods in 2017 primarily due to higher crude oil production and improved realized prices. Natural gas netbacks before hedging were lower for the first and second quarters of 2018 compared to the same periods in 2017 mainly due to lower production as a result of the divestment of non-core Canadian natural gas properties and weaker realized prices. For the three and six months ended June 30, 2018, our crude oil properties accounted for 91% and 86% of our netback before hedging, respectively, compared to 71% for the three and six 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 June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions) | 2018 | 2017 | 2018 | 2017 |
| Cash: | | | | |
| G&A expense | $ 12.1 | $ 12.0 | $ 25.3 | $ 26.3 |
| Share-based compensation expense | 0.5 | — | 2.4 | 0.1 |
| Non-Cash: | | | | |
| Share-based compensation expense | 5.0 | 3.3 | 14.1 | 11.4 |
| Equity swap loss/(gain) | (0.4) | — | (1.4) | 1.0 |
| Total G&A expenses | $ 17.2 | $ 15.3 | $ 40.4 | $ 38.8 |

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| (Per BOE) | 2018 | 2017 | 2018 | 2017 |
| Cash: | | | | |
| G&A expense | $ 1.44 | $ 1.53 | $ 1.57 | $ 1.69 |
| Share-based compensation expense | 0.05 | — | 0.16 | 0.01 |
| Non-Cash: | | | | |
| Share-based compensation expense | 0.59 | 0.42 | 0.87 | 0.74 |
| Equity swap loss/(gain) | (0.04) | 0.01 | (0.09) | 0.07 |
| Total G&A expenses | $ 2.04 | $ 1.96 | $ 2.51 | $ 2.51 |

For the three months and six months ended June 30, 2018, cash G&A expenses were $12.1 million ($1.44/BOE) and $25.3 million ($1.57/BOE), respectively, compared to $12.0 million ($1.53/BOE) and $26.3 million ($1.69/BOE) for the same periods in 2017. Cash G&A expenses decreased on a per BOE basis for the three and six months ended June 30, 2018 compared to the same periods in 2017, primarily due to higher production.

During the second quarter of 2018, we reported cash SBC expense of $0.5 million due to the increase in our share price on outstanding deferred share units, offset by a gain on the unwind of a portion of our outstanding equity hedge contracts. We recorded non-cash SBC of $5.0 million or $0.59/BOE in the second quarter of 2018, which increased from $3.3 million or $0.42/BOE during the same period in 2017 with an increase in the performance multiplier of our Performance Share Unit plan in late 2017.

We have hedges in place on a portion of the outstanding cash-settled grants under our LTI plans. In the second quarter of 2018 we recorded a non-cash mark-to-market gain of $0.4 million on these hedges due to the increase in our share price. As a result of the settlement of the equity hedge contracts during the quarter, we had 195,000 units outstanding, hedged at a weighted average price of $20.60 per share at June 30, 2018.

Based on higher annual production levels and continued focus on costs, we are lowering our annual cash G&A guidance to $1.55/BOE from $1.65/BOE.

**Interest Expense**

For the three and six months ended June 30, 2018, we recorded total interest expense of $9.2 million and $18.4 million, respectively, compared to $10.2 million and $20.4 million for the same periods in 2017. The decrease in interest expense for the three and six months ended June 30, 2018 compared to the same periods in 2017, was primarily due to the impact of a strengthening Canadian dollar on our U.S. dollar denominated interest expense, along with the repayment of a portion of our US$110 million senior notes in June 2017 and 2018 which carry a higher coupon rate.

At June 30, 2018, all of our debt was based on 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 June 30, 2018 | 2017 | Six months ended June 30, 2018 | 2017 |
|---|---|---|---|---|
| Realized: | | | | |
| Foreign exchange (gain)/loss on settlements | $ 0.2 | $ 0.9 | $ 0.3 | $ 1.0 |
| Translation of U.S. dollar cash held in Canada (gain)/loss | (3.7) | — | (11.0) | — |
| Unrealized (gain)/loss | 12.4 | (13.1) | 30.0 | (17.0) |
| Total foreign exchange (gain)/loss | $ 8.9 | $ (12.2) | $ 19.3 | $ (16.0) |
| USD/CDN average exchange rate | 1.29 | 1.34 | 1.28 | 1.33 |
| USD/CDN period end exchange rate | 1.31 | 1.30 | 1.31 | 1.30 |

For the three and six months ended June 30, 2018, we recorded net foreign exchange losses of $8.9 million and $19.3 million, respectively, compared to gains of $12.2 million and $16.0 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 June 30, 2018 to December 31, 2017, the Canadian dollar weakened relative to the U.S. dollar, resulting in an unrealized loss of $30.0 million. See Note 12 to the Interim Financial Statements for further details.

### Capital Investment

| ($ millions) | Three months ended June 30, 2018 | 2017 | Six months ended June 30, 2018 | 2017 |
|---|---|---|---|---|
| Capital spending | $ 177.1 | $ 101.7 | $ 328.6 | $ 222.1 |
| Office capital | 2.3 | 0.3 | 3.7 | 0.4 |
| Sub-total | 179.4 | 102.0 | 332.3 | 222.5 |
| Property and land acquisitions | $ 2.4 | $ 4.7 | $ 14.7 | $ 7.2 |
| Property divestments | 0.2 | (59.8) | (6.8) | (58.9) |
| Sub-total | 2.6 | (55.1) | 7.9 | (51.7) |
| Total (1) | $ 182.0 | $ 46.9 | $ 340.2 | $ 170.8 |

(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 six months ended June 30, 2018, totaled $177.1 million and $328.6 million, respectively, compared to the spending of $101.7 million and $222.1 million for the same periods in 2017. The increase in spending is in line with our strategy to deliver production and liquids growth through 2018. During the quarter we spent $141.8 million on our U.S. crude oil properties, $23.9 million on our Marcellus natural gas assets and $9.0 million on our Canadian waterflood properties.

In the second quarter of 2018, we completed $2.4 million in property and land acquisitions which included minor acquisitions of leases and undeveloped land. There were no asset divestments in the second quarter of 2018, compared to divestments with proceeds of $59.6 million, after closing adjustments, for the same period in 2017.

We are revising our annual capital spending guidance to $585 million (previous guidance range of $535 – $585 million), due to non-operated capital spending in North Dakota and the Marcellus, as well as modest increases on a portion of our materials and services.

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

| ($ millions, except per BOE amounts) | Three months ended June 30, 2018 | 2017 | Six months ended June 30, 2018 | 2017 |
|---|---|---|---|---|
| DD&A expense | $ 73.2 | $ 64.8 | $ 137.2 | $ 125.4 |
| Per BOE | $ 8.66 | $ 8.26 | $ 8.52 | $ 8.09 |

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 $121.5 million at June 30, 2018, compared to $117.7 million at December 31, 2017. For the three and six months ended June 30, 2018, asset retirement obligation settlements were $2.1 million and $5.4 million, respectively, compared to $1.5 million and $4.1 million during the same periods in 2017. See Note 9 to the Interim Financial Statements for further details.

## Income Taxes

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions) | 2018 | 2017 | 2018 | 2017 |
| Current tax expense/(recovery) | $ 0.1 | $ 2.0 | $ 0.1 | $ 2.1 |
| Deferred tax expenses/(recovery) | 3.2 | 38.3 | 15.7 | 67.1 |
| Total tax expense/(recovery) | $ 3.3 | $ 40.3 | $ 15.8 | $ 69.2 |

For the three and six months ended June 30, 2018, we recorded a total tax expense of $3.3 million and $15.8 million, respectively, compared to $40.3 million and $69.2 million for the same periods in 2017. The decrease in the total tax expense is due to lower income in 2018, as well as a reduction to the U.S. federal income tax rate to 21% from 35% effective January 1, 2018 with the enactment of the U.S. Tax Cuts and Jobs Act. See Note 13 to the Interim Financial Statements for further details.

## LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage, including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging and dividend levels. We also assess our leverage relative to our most restrictive debt covenant under our bank credit facility and senior notes, which is a maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At June 30, 2018, our senior debt to adjusted EBITDA ratio was 1.2x and our net debt to adjusted funds flow ratio was 0.5x. Although it is not included in our debt covenants, the net debt to adjusted funds flow ratio is often used by investors and analysts to evaluate our liquidity.

Total debt net of cash at June 30, 2018 was $311.8 million, a decrease of 4% compared to $325.8 million at December 31, 2017. Total debt was comprised of $672.2 million of senior notes less $360.4 million in cash. At June 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 107% and 106% for the three and six months ended June 30, 2018, respectively, compared to 96% and 101% for the same periods in 2017.

Our working capital deficiency, excluding cash and current deferred financial assets and liabilities, increased to $144.3 million at June 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.

At June 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 June 30, 2018:

| Covenant Description | | June 30, 2018 |
|---|---|---|
| **Bank Credit Facility:** | **Maximum Ratio** | |
| Senior debt to adjusted EBITDA (1) | 3.5x | 1.2x |
| Total debt to adjusted EBITDA (1) | 4.0x | 1.2x |
| Total debt to capitalization | 50% | 20% |
| | | |
| **Senior Notes:** | **Maximum Ratio** | |
| Senior debt to adjusted EBITDA (1)(2) | 3.0x - 3.5x | 1.2x |
| Senior debt to consolidated present value of total proved reserves(3) | 60% | 25% |
| | **Minimum Ratio** | |
| Adjusted EBITDA to interest | 4.0x | 16.5 |

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 June 30, 2018 was $186.7 million and $605.6 million, respectively.

"Total debt" is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.

"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes

(1) See "Non-GAAP Measures" in this MD&A for a reconciliation of adjusted EBITDA to net income.

(2) Senior debt to adjusted EBITDA for the senior notes may increase to 3.5x for a period of 6 months 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 June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ millions, except per share amounts) | 2018 | 2017 | 2018 | 2017 |
| Dividends to shareholders | $ 7.3 | $ 7.3 | $ 14.7 | $ 14.5 |
| Per weighted average share (Basic) | $ 0.03 | $ 0.03 | $ 0.06 | $ 0.06 |

During the three and six months ended June 30, 2018, we reported total dividends of $7.3 million or $0.03 per share and $14.7 million or $0.06 per share, respectively, compared to $7.3 million or $0.03 per share and $14.5 million or $0.06 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

| | Six months ended June 30, | |
|---|---|---|
| | 2018 | 2017 |
| Share capital ($ millions) | $ 3,415.0 | $ 3,386.9 |
| | | |
| Common shares outstanding (thousands) | 244,984 | 242,129 |
| Weighted average shares outstanding – basic (thousands) | 244,369 | 241,710 |
| Weighted average shares outstanding – diluted (thousands) | 249,367 | 246,566 |

For the six months ended June 30, 2018, a total of 315,843 shares were issued pursuant to our stock option plan resulting in additional share capital of $4.3 million, and a $0.4 million transfer from paid-in capital to share capital (2017 – nil). For the six months ended June 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). For further details, see Note 14 to the Interim Financial Statements.

At August 9, 2018, we had 245,293,306 common shares outstanding. In addition, an aggregate of 11,376,433 common shares may be issued to settle outstanding grants under the Performance Share Unit ("PSU"), Restricted Share Unit, and stock option plans, assuming the maximum payout multiplier of 2.0 times for the PSUs.

## SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

| | Three months ended June 30, 2018 | | | Three months ended June 30, 2017 | | |
|---|---|---|---|---|---|---|
| ($ millions, except per unit amounts) | Canada | U.S. | Total | Canada | U.S. | Total |
| **Average Daily Production Volumes[1]** | | | | | | |
| Crude oil (bbls/day) | 9,212 | 36,030 | 45,242 | 10,853 | 26,008 | 36,861 |
| Natural gas liquids (bbls/day) | 1,055 | 3,753 | 4,808 | 1,199 | 2,934 | 4,133 |
| Natural gas (Mcf/day) | 29,151 | 227,844 | 256,995 | 46,729 | 224,563 | 271,292 |
| Total average daily production (BOE/day) | 15,126 | 77,757 | 92,883 | 19,840 | 66,369 | 86,209 |
| **Pricing[2]** | | | | | | |
| Crude oil (per bbl) | $ 66.58 | $ 83.41 | $ 79.98 | $ 50.45 | $ 57.83 | $ 55.66 |
| Natural gas liquids (per bbl) | 50.20 | 27.18 | 32.23 | 37.35 | 20.14 | 25.14 |
| Natural gas (per Mcf) | 2.07 | 2.76 | 2.68 | 3.59 | 3.46 | 3.48 |
| **Capital Expenditures** | | | | | | |
| Capital spending | $ 11.4 | $ 165.7 | $ 177.1 | $ 10.6 | $ 91.1 | $ 101.7 |
| Acquisitions | 1.0 | 1.4 | 2.4 | 1.1 | 3.6 | 4.7 |
| Divestments | 0.2 | — | 0.2 | (59.6) | (0.2) | (59.8) |
| **Netback[3] Before Hedging** | | | | | | |
| Oil and natural gas sales | $ 66.9 | $ 339.9 | $ 406.8 | $ 69.2 | $ 212.9 | $ 282.1 |
| Royalties | (10.7) | (68.7) | (79.4) | (14.3) | (42.1) | (56.4) |
| Production taxes | (0.7) | (21.9) | (22.6) | (0.8) | (13.0) | (13.8) |
| Cash operating expenses | (17.7) | (43.3) | (61.0) | (19.4) | (26.8) | (46.2) |
| Transportation costs | (2.8) | (27.3) | (30.1) | (3.1) | (26.1) | (29.2) |
| Netback before hedging | $ 35.0 | $ 178.7 | $ 213.7 | $ 31.6 | $ 104.9 | $ 136.5 |
| **Other Expenses** | | | | | | |
| Commodity derivative instruments loss/(gain) | $ 91.0 | $ — | $ 91.0 | $ (31.9) | $ — | $ (31.9) |
| General and administrative expense[4] | 6.3 | 10.9 | 17.2 | 7.9 | 7.4 | 15.3 |
| Current income tax expense/(recovery) | — | 0.1 | 0.1 | — | 2.0 | 2.0 |

| | Six months ended June 30, 2018 | | | Six months ended June 30, 2017 | | |
|---|---|---|---|---|---|---|
| ($ millions, except per unit amounts) | Canada | U.S. | Total | Canada | U.S. | Total |
| **Average Daily Production Volumes[1]** | | | | | | |
| Crude oil (bbls/day) | 9,362 | 32,002 | 41,364 | 11,875 | 23,155 | 35,030 |
| Natural gas liquids (bbls/day) | 1,151 | 3,298 | 4,449 | 1,301 | 2,347 | 3,648 |
| Natural gas (Mcf/day) | 31,131 | 228,010 | 259,141 | 57,575 | 223,818 | 281,393 |
| Total average daily production (BOE/day) | 15,701 | 73,302 | 89,003 | 22,772 | 62,805 | 85,577 |
| **Pricing[2]** | | | | | | |
| Crude oil (per bbl) | $ 59.63 | $ 79.94 | $ 75.34 | $ 51.11 | $ 59.32 | $ 56.54 |
| Natural gas liquids (per bbl) | 47.46 | 24.39 | 30.36 | 37.21 | 26.88 | 30.57 |
| Natural gas (per Mcf) | 2.63 | 3.16 | 3.09 | 3.62 | 3.54 | 3.56 |
| **Capital Expenditures** | | | | | | |
| Capital spending | $ 24.6 | $ 304.0 | $ 328.6 | $ 35.6 | $ 186.5 | $ 222.1 |
| Acquisitions | 2.1 | 12.6 | 14.7 | 2.7 | 4.5 | 7.2 |
| Divestments | (0.7) | (6.1) | (6.8) | (58.7) | (0.2) | (58.9) |
| **Netback[3] Before Hedging** | | | | | | |
| Oil and natural gas sales | $ 127.6 | $ 607.7 | $ 735.3 | $ 156.3 | $ 403.5 | $ 559.8 |
| Royalties | (20.7) | (122.2) | (142.9) | (26.2) | (80.1) | (106.3) |
| Production taxes | (1.5) | (37.3) | (38.8) | (1.9) | (22.3) | (24.2) |
| Cash operating expenses | (38.2) | (76.5) | (114.7) | (45.9) | (50.5) | (96.4) |
| Transportation costs | (5.8) | (51.2) | (57.0) | (7.5) | (51.3) | (58.8) |
| Netback before hedging | $ 61.4 | $ 320.5 | $ 381.9 | $ 74.8 | $ 199.3 | $ 274.1 |
| **Other Expenses** | | | | | | |
| Commodity derivative instruments loss/(gain) | $ 111.4 | $ — | $ 111.4 | $ (89.5) | $ — | $ (89.5) |
| General and administrative expense[4] | 21.7 | 18.7 | 40.4 | 25.7 | 13.1 | 38.8 |
| Current income tax expense/(recovery) | — | 0.1 | 0.1 | — | 2.1 | 2.1 |

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

## QUARTERLY FINANCIAL INFORMATION

| ($ millions, except per share amounts) | Oil and Natural Gas Sales, Net of Royalties | Net Income/(Loss) | Net Income/(Loss) Per Share Basic | Net Income/(Loss) Per Share Diluted |
|---|---|---|---|---|
| **2018** | | | | |
| Second Quarter | $ 327.4 | $ 12.4 | $ 0.05 | $ 0.05 |
| First Quarter | 265.0 | 29.6 | 0.12 | 0.12 |
| Total 2018 | $ 592.4 | $ 42.0 | $ 0.17 | $ 0.17 |
| **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 second quarter of 2018 compared to the first quarter of 2018 due to increased production volumes and higher realized crude oil prices. Net income decreased in the second quarter of 2018 compared to the first quarter of 2018 due to a $91.0 million loss on commodity hedges. 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 production. Net income has stabilized in 2018, after a gain was recorded on asset divestments in the second quarter of 2017 and reversal of the valuation allowance on our deferred tax asset in the fourth quarter of 2016.

### U.S. Filing Status

Pursuant to U.S. securities regulations, we are required to reassess our U.S. securities filing status annually at June 30. As at June 30, 2018, we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

## 2018 UPDATED GUIDANCE

We are increasing our average annual production guidance range to 91,000 – 93,000 BOE/day from 86,000 – 91,000 BOE/day and narrowing our average annual crude oil and natural gas liquids production range to 49,000 – 50,000 bbls/day from 46,000 – 50,000 bbls/day. We are revising our annual capital spending guidance to $585 million, from our previous guidance range of $535 – $585 million, and reducing our annual cash G&A to $1.55/BOE from $1.65/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 (from $535 – $585 million) |
| Average annual production | 91,000 – 93,000 BOE/day (from 86,000 – 91,000 BOE/day) |
| Average annual crude oil and natural gas liquids production | 49,000 – 50,000 bbls/day (from 46,000 – 50,000 bbls/day) |
| Average royalty and production tax rate (% of gross sales, before transportation) | 25% |
| Operating expenses | $7.00/BOE |
| Transportation costs | $3.60/BOE |
| Cash G&A expenses | $1.55/BOE (from $1.65/BOE) |

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

(1) Excludes transportation costs.

## NON-GAAP MEASURES

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

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

| **Calculation of Netback** | **Three months ended June 30,** | | **Six months ended June 30,** | |
|---|---|---|---|---|
| ($ millions) | **2018** | **2017** | **2018** | **2017** |
| Oil and natural gas sales | $ 406.8 | $ 282.1 | $ 735.3 | $ 559.8 |
| Less: | | | | |
| Royalties | (79.4) | (56.4) | (142.9) | (106.3) |
| Production taxes | (22.6) | (13.8) | (38.8) | (24.2) |
| Cash operating expenses[1] | (61.0) | (46.2) | (114.7) | (96.4) |
| Transportation costs | (30.1) | (29.2) | (57.0) | (58.8) |
| Netback before hedging | $ 213.7 | $ 136.5 | $ 381.9 | $ 274.1 |
| Cash gains/(losses) on derivative instruments | (19.3) | 2.2 | (9.1) | 8.8 |
| Netback after hedging | $ 194.4 | $ 138.7 | $ 372.8 | $ 282.9 |

(1) Total operating expenses have been adjusted to exclude a non-cash gain of $0.1 million for the three and six months ended June 30, 2018, and non-cash gains of $0.4 million and $0.3 million, respectively, in the three and six months ended June 30, 2017.

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

| **Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow** | **Three months ended June 30,** | | **Six months ended June 30,** | |
|---|---|---|---|---|
| ($ millions) | **2018** | **2017** | **2018** | **2017** |
| Cash flow from operating activities | $ 141.8 | $ 98.3 | $ 301.1 | $ 226.2 |
| Asset retirement obligation expenditures | 2.0 | 1.5 | 5.4 | 4.1 |
| Changes in non-cash operating working capital | 29.9 | 14.4 | 22.4 | 3.8 |
| Adjusted funds flow | $ 173.7 | $ 114.2 | $ 328.9 | $ 234.1 |

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

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

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

| **Calculation of Adjusted Payout Ratio** | **Three months ended June 30,** | | **Six months ended June 30,** | |
|---|---|---|---|---|
| ($ millions) | **2018** | **2017** | **2018** | **2017** |
| Dividends | $ 7.3 | $ 7.3 | $ 14.7 | $ 14.5 |
| Capital and office expenditures | 179.4 | 102.0 | 332.3 | 222.5 |
| Sub-total | $ 186.7 | $ 109.3 | $ 347.0 | $ 237.0 |
| Adjusted funds flow | $ 173.7 | $ 114.2 | $ 328.9 | $ 234.1 |
| Adjusted payout ratio (%) | 107% | 96% | 106% | 101% |

**"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) | | June 30, 2018 |
|---|---|---|
| Net income/(loss) | $ | 73.4 |
| Add: | | |
| Interest | | 36.7 |
| Current and deferred tax expense/(recovery) | | 28.7 |
| DD&A and asset impairment | | 262.6 |
| Other non-cash charges[2] | | 204.2 |
| Adjusted EBITDA | $ | 605.6 |

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at June 30, 2018 include the six months ended June 30, 2018 and the third and fourth quarters 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", "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 June 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 April 1, 2018 and ended June 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 and to negotiate relief if required; our future acquisitions and dispositions, expecting timing thereof and use of proceeds therefrom; and the amount of future cash dividends that we may pay to our shareholders.*

*The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued* *availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; our ability to negotiate debt covenant relief under our bank credit facility and outstanding senior notes if required; the availability of third party services; and the extent of our liabilities. In addition, our updated 2018 guidance contained in this MD&A is based on the following forward prices: a WTI price of US$66.00/bbl, a NYMEX price of US$2.84/Mcf, and a USD/CDN exchange rate of 1.30. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.*

*The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued low commodity prices environment or further volatility in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our AIF, 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 | June 30, 2018 | December 31, 2017 |
|---|---|---|---|
| **Assets** | | | |
| Current Assets | | | |
| Cash and cash equivalents | | $ 360,422 | $ 346,548 |
| Accounts receivable | 4 | 178,785 | 129,386 |
| Income tax receivable | 13 | 53,577 | 1,190 |
| Deferred financial assets | 15 | 255 | 3,852 |
| Other current assets | | 2,743 | 5,902 |
| | | 595,782 | 486,878 |
| Property, plant and equipment: | | | |
| Oil and natural gas properties (full cost method) | 5 | 1,134,090 | 889,967 |
| Other capital assets, net | 5 | 12,129 | 10,064 |
| Property, plant and equipment | | 1,146,219 | 900,031 |
| Goodwill | | 647,272 | 638,878 |
| Deferred income tax asset | 13 | 569,623 | 569,937 |
| Income tax receivable | 13 | — | 50,108 |
| **Total Assets** | | $ 2,958,896 | $ 2,645,832 |
| **Liabilities** | | | |
| Current liabilities | | | |
| Accounts payable | 7 | $ 318,066 | $ 213,978 |
| Dividends payable | | 2,450 | 2,421 |
| Current portion of long-term debt | 8 | 58,893 | 27,656 |
| Deferred financial liabilities | 15 | 94,697 | 28,642 |
| | | 474,106 | 272,697 |
| Deferred financial liabilities | 15 | 41,090 | 9,907 |
| Long-term debt | 8 | 613,311 | 644,723 |
| Asset retirement obligation | 9 | 121,468 | 117,736 |
| | | 775,869 | 772,366 |
| **Total Liabilities** | | 1,249,975 | 1,045,063 |
| **Shareholders’ Equity** | | | |
| Share capital – authorized unlimited common shares, no par value | | | |
| Issued and outstanding: June 30, 2018 – 245 million shares | | | |
| December 31, 2017 – 242 million shares | 14 | 3,415,044 | 3,386,946 |
| Paid-in capital | | 65,697 | 75,375 |
| Accumulated deficit | | (2,097,302) | (2,124,676) |
| Accumulated other comprehensive income/(loss) | | 325,482 | 263,124 |
| | | 1,708,921 | 1,600,769 |
| **Total Liabilities & Shareholders' Equity** | | $ 2,958,896 | $ 2,645,832 |
| **Contingencies** | 16 | | |

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

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

| (CDN$ thousands, except per share amounts) unaudited | Note | Three months ended June 30, 2018 | Three months ended June 30, 2017 | Six months ended June 30, 2018 | Six months ended June 30, 2017 |
|---|---|---|---|---|---|
| **Revenues** | | | | | |
| Oil and natural gas sales, net of royalties | 10 | $ 327,384 | $ 225,695 | $ 592,404 | $ 453,511 |
| Commodity derivative instruments gain/(loss) | 15 | (90,951) | 31,948 | (111,415) | 89,510 |
| | | 236,433 | 257,643 | 480,989 | 543,021 |
| **Expenses** | | | | | |
| Operating | | 60,879 | 45,768 | 114,640 | 96,149 |
| Transportation | | 30,123 | 29,205 | 57,044 | 58,833 |
| Production taxes | | 22,649 | 13,803 | 38,784 | 24,167 |
| General and administrative | 11 | 17,189 | 15,340 | 40,413 | 38,833 |
| Depletion, depreciation and accretion | | 73,165 | 64,779 | 137,211 | 125,359 |
| Interest | | 9,249 | 10,211 | 18,352 | 20,352 |
| Foreign exchange (gain)/loss | 12 | 8,911 | (12,150) | 19,282 | (16,008) |
| Gain on divestment of assets | 5 | — | (78,400) | — | (78,400) |
| Other expense/(income) | | (1,447) | (558) | (2,630) | (1,043) |
| | | 220,718 | 87,998 | 423,096 | 268,242 |
| **Income/(Loss) before taxes** | | 15,715 | 169,645 | 57,893 | 274,779 |
| Current income tax expense/(recovery) | 13 | 72 | 2,040 | 138 | 2,114 |
| Deferred income tax expense/(recovery) | 13 | 3,239 | 38,303 | 15,714 | 67,070 |
| **Net Income/(Loss)** | | $ 12,404 | $ 129,302 | $ 42,041 | $ 205,595 |
| **Other Comprehensive Income/(Loss)** | | | | | |
| Change in cumulative translation adjustment | | 27,990 | (36,354) | 62,358 | (46,656) |
| **Total Comprehensive Income/(Loss)** | | $ 40,394 | $ 92,948 | $ 104,399 | $ 158,939 |
| **Net income/(Loss) per share** | | | | | |
| Basic | 14 | $ 0.05 | $ 0.53 | $ 0.17 | $ 0.85 |
| Diluted | 14 | $ 0.05 | $ 0.52 | $ 0.17 | $ 0.83 |

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 | Six months ended June 30, 2018 | 2017 |
|---|---|---|
| **Share Capital** | | |
| Balance, beginning of year | $ 3,386,946 | $ 3,365,962 |
| Share-based compensation – settled | 23,389 | 20,984 |
| Stock Option Plan – cash | 4,344 | — |
| Stock Option Plan – exercised | 365 | — |
| Balance, end of period | $ 3,415,044 | $ 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 | 14,076 | 11,430 |
| Stock Option Plan – exercised | (365) | — |
| Balance, end of period | $ 65,697 | $ 64,229 |
| **Accumulated Deficit** | | |
| Balance, beginning of year | $ (2,124,676) | $ (2,332,641) |
| Net income/(loss) | 42,041 | 205,595 |
| Dividends declared | (14,667) | (14,505) |
| Balance, end of period | $ (2,097,302) | $ (2,141,551) |
| **Accumulated Other Comprehensive Income/(Loss)** | | |
| Balance, beginning of year | $ 263,124 | $ 353,401 |
| Change in cumulative translation adjustment | 62,358 | (46,656) |
| Balance, end of period | $ 325,482 | $ 306,745 |
| **Total Shareholders' Equity** | $ 1,708,921 | $ 1,616,369 |

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 June 30, 2018 | Three months ended June 30, 2017 | Six months ended June 30, 2018 | Six months ended June 30, 2017 |
|---|---|---|---|---|---|
| **Operating Activities** | | | | | |
| Net income/(loss) | | $ 12,404 | $ 129,302 | $ 42,041 | $ 205,595 |
| Non-cash items add/(deduct): | | | | | |
| Depletion, depreciation and accretion | | 73,165 | 64,779 | 137,211 | 125,359 |
| Changes in fair value of derivative instruments | 15 | 71,213 | (30,031) | 100,835 | (79,960) |
| Deferred income tax expense/(recovery) | 13 | 3,239 | 38,303 | 15,714 | 67,070 |
| Foreign exchange (gain)/loss on debt and working capital | 12 | 12,386 | (13,064) | 30,035 | (16,975) |
| Share-based compensation | 14 | 4,997 | 3,310 | 14,076 | 11,430 |
| Translation of U.S. dollar cash held in Canada | 12 | (3,696) | — | (11,042) | — |
| Gain on divestment of assets | 5 | — | (78,400) | — | (78,400) |
| Asset retirement obligation expenditures | 9 | (2,053) | (1,523) | (5,384) | (4,064) |
| Changes in non-cash operating working capital | 17 | (29,888) | (14,382) | (22,419) | (3,838) |
| Cash flow from/(used in) operating activities | | 141,767 | 98,294 | 301,067 | 226,217 |
| **Financing Activities** | | | | | |
| Dividends | 14,17 | (7,344) | (7,264) | (14,638) | (14,489) |
| Bank credit facility | | — | (4,043) | — | (23,272) |
| Senior notes | 8 | (29,044) | (29,084) | (29,044) | (29,084) |
| Proceeds from the issuance of shares | 14 | 2,915 | — | 4,344 | — |
| Cash flow from/(used in) financing activities | | (33,473) | (40,391) | (39,338) | (66,845) |
| **Investing Activities** | | | | | |
| Capital and office expenditures | 17 | (147,898) | (112,093) | (256,110) | (206,264) |
| Property and land acquisitions | | (2,392) | (4,713) | (8,582) | (7,249) |
| Property divestments | | (182) | 59,842 | 706 | 58,942 |
| Cash flow from/(used in) investing activities | | (150,472) | (56,964) | (263,986) | (154,571) |
| Effect of exchange rate changes on cash and cash equivalents | | 6,205 | (9,479) | 16,131 | (13,048) |
| Change in cash and cash equivalents | | (35,973) | (8,540) | 13,874 | (8,247) |
| Cash and cash equivalents, beginning of period | | 396,395 | 393,598 | 346,548 | 393,305 |
| **Cash and cash equivalents, end of period** | | **$ 360,422** | **$ 385,058** | **$ 360,422** | **$ 385,058** |

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 six months ended June 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 asset and related lease liability on the balance sheet for all leases, including operating leases. The standard does not apply to oil and gas exploration rights, intangible assets or inventory. The new standard also expands disclosures related to the amount, timing and uncertainty of cash flows arising from leases. The standard will be applied using a modified retrospective approach and provides for certain practical expedients at the date of adoption. The ASU is effective January 1, 2019. Enerplus does not expect to early adopt the standard. The Company is continuing to review existing contracts to determine the impact to the Consolidated Financial Statements of adopting the new standard. The Company is also addressing system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new standard.

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

In January 2017, the FASB issued ASU 2017-04, *Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment (Topic 350)*. This standard eliminates Step 2 of the goodwill impairment test and requires a goodwill impairment charge for the amount that the carrying amount of the reporting unit exceeds the reporting unit's fair value. The updated guidance is effective January 1, 2020, and will be applied prospectively. Enerplus does not expect to early adopt the standard. The amended standard may affect goodwill impairment tests past the adoption date, the impact of which is not known.

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

## 4) ACCOUNTS RECEIVABLE

| ($ thousands) | June 30, 2018 | December 31, 2017 |
|---|---|---|
| Accrued revenue | $ 148,450 | $ 102,051 |
| Accounts receivable – trade | 34,314 | 30,787 |
| Allowance for doubtful accounts | (3,979) | (3,452) |
| Total accounts receivable, net of allowance for doubtful accounts | $ 178,785 | $ 129,386 |

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

| As of June 30, 2018<br>($ thousands) | Cost | Accumulated Depletion, Depreciation, and Impairment | Net Book Value |
|---|---|---|---|
| Oil and natural gas properties | $ 14,233,685 | $ (13,099,595) | $ 1,134,090 |
| Other capital assets | 112,012 | (99,883) | 12,129 |
| Total PP&E | $ 14,345,697 | $ (13,199,478) | $ 1,146,219 |

| As of December 31, 2017<br>($ 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 six months ended June 30, 2018. During the six months ended June 30, 2017, Enerplus recorded a gain on asset divestments of $78.4 million on the sale of certain Canadian assets for proceeds of $59.6 million, after closing adjustments.

## 6) ASSET IMPAIRMENT

There was no impairment recorded for the six months ended June 30, 2018 and 2017.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from June 30, 2017 through June 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 |
|---|---|---|---|---|---|
| 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 |
| Q2 2017 | 48.95 | 1.33 | 60.79 | 3.05 | 2.79 |

## 7) ACCOUNTS PAYABLE

| ($ thousands) | June 30, 2018 | December 31, 2017 |
|---|---|---|
| Accrued payables | $ 153,960 | $ 96,743 |
| Accounts payable – trade | 164,106 | 117,235 |
| Total accounts payable | $ 318,066 | $ 213,978 |

## 8) DEBT

| ($ thousands) | June 30, 2018 | December 31, 2017 |
|---|---|---|
| Current: | | |
| Senior notes | $ 58,893 | $ 27,656 |
| Long-term: | | |
| Bank credit facility | — | — |
| Senior notes | 613,311 | 644,723 |
| Total debt | $ 672,204 | $ 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 | $ 137,897 |
| May 15, 2012 | May 15 and Nov 15 | Bullet payment on May 15, 2019 | 4.34% | CDN$30,000 | CDN$30,000 | 30,000 |
| May 15, 2012 | May 15 and Nov 15 | Bullet payment on May 15, 2022 | 4.40% | US$20,000 | US$20,000 | 26,266 |
| May 15, 2012 | May 15 and Nov 15 | 5 equal annual installments beginning May 15, 2020 | 4.40% | US$355,000 | US$298,000 | 391,363 |
| June 18, 2009 | June 18 and Dec 18 | 3 equal annual installments June 18, 2019 - 2021 | 7.97% | US$225,000 | US$66,000 | 86,678 |
| | | | | | **Total carrying value** | $ 672,204 |

During the three months ended June 30, 2018 and 2017, Enerplus made its first and second US$22 million principal repayments on its 2009 senior notes.

## 9) ASSET RETIREMENT OBLIGATION

| ($ thousands) | Six months ended June 30, 2018 | Year ended December 31, 2017 |
|---|---|---|
| Balance, beginning of year | $ 117,736 | $ 181,700 |
| Change in estimates | 9,041 | 13,064 |
| Property acquisitions and development activity | 827 | 1,322 |
| Dispositions | (3,724) | (72,306) |
| Settlements | (5,384) | (12,907) |
| Accretion expense | 2,972 | 6,863 |
| Balance, end of period | $ 121,468 | $ 117,736 |

Enerplus has estimated the present value of its asset retirement obligation to be $121.5 million at June 30, 2018 based on a total undiscounted liability of $325.4 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 5.67% (December 31, 2017 – 5.73%).

### 10) OIL AND NATURAL GAS SALES

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ thousands) | 2018 | 2017 | 2018 | 2017 |
| Oil and natural gas sales | $ 406,823 | $ 282,090 | $ 735,375 | $ 559,835 |
| Royalties[1] | (79,439) | (56,395) | (142,971) | (106,324) |
| Oil and natural gas sales, net of royalties | $ 327,384 | $ 225,695 | $ 592,404 | $ 453,511 |

(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 six months ended June 30, 2018 are as follows:

| Three months ended June 30, 2018<br>($ thousands) | Total revenue, net of royalties[1] | Crude oil[2] | Natural gas[2] | Natural gas liquids[2] | Other[3] |
|---|---|---|---|---|---|
| Canada | $ 56,128 | $ 45,023 | $ 6,581 | $ 3,774 | $ 750 |
| United States | 271,256 | 218,039 | 45,692 | 7,525 | — |
| Total | $ 327,384 | $ 263,062 | $ 52,273 | $ 11,299 | $ 750 |

| Six months ended June 30, 2018<br>($ thousands) | Total revenue, net of royalties[1] | Crude oil[2] | Natural gas[2] | Natural gas liquids[2] | Other[3] |
|---|---|---|---|---|---|
| Canada | $ 106,903 | $ 81,009 | $ 16,221 | $ 7,833 | $ 1,840 |
| United States | 485,501 | 369,262 | 104,287 | 11,952 | — |
| Total | $ 592,404 | $ 450,271 | $ 120,508 | $ 19,785 | $ 1,840 |

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

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

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

### 11) GENERAL AND ADMINISTRATIVE EXPENSE

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ thousands) | 2018 | 2017 | 2018 | 2017 |
| General and administrative expense | $ 12,131 | $ 11,981 | $ 25,336 | $ 26,252 |
| Share-based compensation expense[1] | 5,058 | 3,359 | 15,077 | 12,581 |
| General and administrative expense | $ 17,189 | $ 15,340 | $ 40,413 | $ 38,833 |

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

### 12) FOREIGN EXCHANGE

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ thousands) | 2018 | 2017 | 2018 | 2017 |
| Realized: | | | | |
| Foreign exchange (gain)/loss | $ 221 | $ 914 | $ 289 | $ 967 |
| Translation of U.S. dollar cash held in Canada (gain)/loss | (3,696) | — | (11,042) | — |
| Unrealized: | | | | |
| Translation of U.S. dollar debt and working capital (gain)/loss | 12,386 | (13,064) | 30,035 | (16,975) |
| Foreign exchange (gain)/loss | $ 8,911 | $ (12,150) | $ 19,282 | $ (16,008) |

## 13) INCOME TAXES

| ($ thousands) | Three months ended June 30, 2018 | Three months ended June 30, 2017 | Six months ended June 30, 2018 | Six months ended June 30, 2017 |
|---|---|---|---|---|
| Current tax expense/(recovery) | | | | |
| United States | $ 72 | $ 2,040 | $ 138 | $ 2,114 |
| Deferred tax expense/(recovery) | | | | |
| Canada | (20,460) | 25,563 | (25,970) | 39,182 |
| United States | 23,699 | 12,740 | 41,684 | 27,888 |
| | $ 3,239 | $ 38,303 | $ 15,714 | $ 67,070 |
| Income tax expense/(recovery) | $ 3,311 | $ 40,343 | $ 15,852 | $ 69,184 |

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 $569.6 million at June 30, 2018 (December 31, 2017 – $569.9 million).

At June 30, 2018, the current income tax receivable included $52.3 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

| **Authorized unlimited number of common shares issued:** (thousands) | Six months ended June 30, 2018 Shares | Six months ended June 30, 2018 Amount | Year ended December 31, 2017 Shares | Year ended December 31, 2017 Amount |
|---|---|---|---|---|
| Balance, beginning of year | 242,129 | $ 3,386,946 | 240,483 | $ 3,365,962 |
| Issued for cash: | | | | |
| Stock Option Plan | 316 | 4,344 | — | — |
| Non-cash: | | | | |
| Share-based compensation – settled | 2,539 | 23,389 | 1,646 | 20,984 |
| Stock Option Plan – exercised | — | 365 | — | — |
| Balance, end of period | 244,984 | $ 3,415,044 | 242,129 | $ 3,386,946 |

Dividends declared to shareholders for the three and six months ended June 30, 2018 were $7.3 million and $14.7 million, respectively (2017 – $7.3 million and $14.5 million, respectively).

### b) Share-based Compensation

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

| ($ thousands) | Three months ended June 30, 2018 | Three months ended June 30, 2017 | Six months ended June 30, 2018 | Six months ended June 30, 2017 |
|---|---|---|---|---|
| Cash: | | | | |
| Long-term incentive plans expense | $ 435 | $ (15) | $ 2,381 | $ 140 |
| Non-cash: | | | | |
| Long-term incentive plans | 4,997 | 3,310 | 14,076 | 11,430 |
| Equity swap (gain)/loss | (374) | 64 | (1,380) | 1,011 |
| Share-based compensation expense | $ 5,058 | $ 3,359 | $ 15,077 | $ 12,581 |

### 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 six months ended June 30, 2018:

| For the six months ended June 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 | 1,454 | 800 | 2,331 |
| Vested | (55) | (1,459) | (1,080) | (2,594) |
| Forfeited | — | (6) | (42) | (48) |
| Balance, end of period | 390 | 2,702 | 1,787 | 4,879 |

**Cash-settled LTI Plans**

For the three and six months ended June 30, 2018, the Company recorded cash share-based compensation expense of $0.4 million and $2.4 million, respectively (June 30, 2017 – nil and $0.1 million, respectively). For the three and six months ended June 30, 2018, the Company made cash payments of $0.4 million related to its cash-settled plans (June 30, 2017 – nil and $0.1 million, respectively).

As of June 30, 2018, a liability of $6.4 million (December 31, 2017 – $4.5 million) with respect to the DSU plan has been recorded to Accounts Payable on the Consolidated Balance Sheets.

**Equity-settled LTI Plans**

For the three and six months ended June 30, 2018, the Company recorded non-cash share-based compensation expense of $5.0 million and $14.1 million, respectively (2017 – $3.3 million and $11.4 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 June 30, 2018 ($ thousands, except for years) | PSU(1) | RSU | Total |
|---|---|---|---|
| Cumulative recognized share-based compensation expense | $ 22,339 | $ 8,726 | $ 31,065 |
| Unrecognized share-based compensation expense | 13,108 | 8,978 | 22,086 |
| Fair value | $ 35,447 | $ 17,704 | $ 53,151 |
| Weighted-average remaining contractual term (years) | 1.8 | 1.6 | |

(1) Includes estimated performance multipliers.

### ii) Stock Option Plan

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

| Period ended June 30, 2018 | Number of Options (thousands) | Weighted Average Exercise Price |
|---|---|---|
| Options outstanding, beginning of year | 5,486 | $ 18.25 |
| Exercised | (316) | 13.75 |
| Forfeited | (39) | 21.95 |
| Expired | (638) | 30.20 |
| Options outstanding, end of period | 4,493 | $ 16.84 |
| Options exercisable, end of period | 4,493 | $ 16.84 |

At June 30, 2018, Enerplus had 4,493,119 options that were exercisable at a weighted average exercise price of $16.84 with a weighted average remaining contractual term of 1.3 years, giving an aggregate intrinsic value of $8.0 million (June 30, 2017 – 2.1 years and nil). The intrinsic value of options exercised for the three and six months ended June 30, 2018 was $0.5 million and $0.7 million, respectively (June 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 June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| (thousands, except per share amounts) | 2018 | 2017 | 2018 | 2017 |
| Net income/(loss) | $ 12,404 | $ 129,302 | $ 42,041 | $ 205,595 |
| Weighted average shares outstanding – Basic | 244,862 | 242,127 | 244,369 | 241,710 |
| Dilutive impact of share-based compensation | 5,260 | 4,856 | 4,998 | 4,856 |
| Weighted average shares outstanding – Diluted | 250,122 | 246,983 | 249,367 | 246,566 |
| Net income/(loss) per share | | | | |
| Basic | $ 0.05 | $ 0.53 | $ 0.17 | $ 0.85 |
| Diluted | $ 0.05 | $ 0.52 | $ 0.17 | $ 0.83 |

## 15) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

### a) Fair Value Measurements

At June 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 June 30, 2018, the senior notes had a carrying value of $672.2 million and a fair value of $671.2 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 six months ended June 30, 2018 and 2017:

| | Three months ended June 30, | | Six months ended June 30, | | |
|---|---|---|---|---|---|
| **Gain/(Loss)** ($ thousands) | 2018 | 2017 | 2018 | 2017 | Income Statement Presentation |
| Electricity Swaps | $ 78 | $ 387 | $ 62 | $ 270 | Operating expense |
| Equity Swaps | 374 | (64) | 1,380 | (1,011) | G&A expense |
| Commodity Derivative Instruments: | | | | | |
| Oil | (70,905) | 27,280 | (100,760) | 71,638 | Commodity derivative instruments |
| Gas | (760) | 2,428 | (1,517) | 9,063 | |
| Total | $ (71,213) | $ 30,031 | $ (100,835) | $ 79,960 | |

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

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ thousands) | 2018 | 2017 | 2018 | 2017 |
| Change in fair value gain/(loss) | $ (71,665) | $ 29,708 | $ (102,277) | $ 80,701 |
| Net realized cash gain/(loss) | (19,286) | 2,240 | (9,138) | 8,809 |
| Commodity derivative instruments gain/(loss) | $ (90,951) | $ 31,948 | $ (111,415) | $ 89,510 |

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

| | June 30, 2018 | | | December 31, 2017 | | |
|---|---|---|---|---|---|---|
| | Assets | Liabilities | | Assets | Liabilities | |
| ($ thousands) | Current | Current | Long-term | Current | Current | Long-term |
| Electricity Swaps | $ 62 | $ — | $ — | $ — | $ — | $ — |
| Equity Swaps | — | 739 | — | — | 2,119 | — |
| Commodity Derivative Instruments: | | | | | | |
| Oil | — | 93,958 | 41,090 | 2,142 | 26,523 | 9,907 |
| Gas | 193 | — | — | 1,710 | — | — |
| Total | $ 255 | $ 94,697 | $ 41,090 | $ 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 August 9, 2018:

*Crude Oil Instruments:*

| Instrument Type(1)(2) | bbls/day | US$/bbl |
|---|---|---|
| Jul 1, 2018 – Sep 30, 2018 | | |
| WTI Swap | 3,000 | 53.73 |
| WTI Purchased Put | 18,000 | 52.53 |
| WTI Sold Call | 18,000 | 61.22 |
| WTI Sold Put | 18,000 | 42.71 |
| WCS Differential Swap (Sale) | 3,000 | (14.46) |
| Oct 1, 2018 – Dec 31, 2018 | | |
| WTI Swap | 3,000 | 53.73 |
| WTI Purchased Put | 20,000 | 52.48 |
| WTI Sold Call | 20,000 | 61.10 |
| WTI Sold Put | 20,000 | 42.74 |
| WCS Differential Swap (Sale) | 3,000 | (14.46) |
| Jan 1, 2019 – Mar 31, 2019 | | |
| WTI Swap | 3,000 | 53.73 |
| WTI Purchased Put | 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) |
| 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 | 14,000 | 57.14 |
| WTI Sold Call | 14,000 | 72.07 |
| WTI Sold Put | 14,000 | 46.71 |

(1) Transactions with a common term have been aggregated and presented at a weighted average price/bbl before premiums.
(2) The total average deferred premium on three way collars is US$1.59/bbl from July 1, 2018 to December 31, 2020.

*Natural Gas Instruments:*

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

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

*Electricity Instruments:*

| Instrument Type | MWh | CDN$/Mwh |
|---|---|---|
| Jul 1, 2018 – Aug 30, 2018 | | |
| AESO Power Swap[(1)] | 2.0 | 55.00 |

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

### Foreign Exchange Risk:

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

### Interest Rate Risk:

At June 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 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 June 30, 2018, approximately 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 June 30, 2018 was $4.0 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 June 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 June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ thousands) | 2018 | 2017 | 2018 | 2017 |
| Accounts receivable | $ (44,863) | $ (3,617) | $ (51,500) | $ 18,055 |
| Other current assets | 1,539 | 1,770 | 3,160 | (2,541) |
| Accounts payable | 13,436 | (12,535) | 25,921 | (19,352) |
| | $ (29,888) | $ (14,382) | $ (22,419) | $ (3,838) |

### b) Changes in Other Non-Cash Working Capital

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ thousands) | 2018 | 2017 | 2018 | 2017 |
| Non-cash financing activities(1) | $ 3 | $ — | $ 29 | $ 16 |
| Non-cash investing activities(2) | 31,463 | (10,071) | 76,123 | 16,251 |

(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

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ thousands) | 2018 | 2017 | 2018 | 2017 |
| Income taxes paid/(received) | $ 2 | $ 1,875 | $ (83) | $ 1,939 |
| Interest paid | 14,937 | 16,807 | 18,193 | 20,451 |

## BOARD OF DIRECTORS

**Elliott Pew**(1)(2)
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)
Corporate Director
Calgary, Alberta

**Robert B. Hodgins**(3)(6)(9)
Corporate Director
Calgary, Alberta

**Susan M. MacKenzie**(5)(7)(12)
Corporate Director
Calgary, Alberta

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

**Jeffrey W. Sheets**(5)(9)(11)
Corporate Director
Houston, Texas

**Sheldon B. Steeves**(8)(11)
Corporate Director
Calgary, Alberta

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

## OFFICERS

### ENERPLUS CORPORATION

**Ian C. Dundas**
President & Chief Executive Officer

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

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

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

**Daniel J. Fitzgerald**
Vice President, Business Development

**John E. Hoffman**
Vice President, Canadian Operations

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

**Edward L. McLaughlin**
President, U.S. Operations

**Shaina B. Morihira**
Vice President, Finance

# CORPORATE INFORMATION

### OPERATING COMPANIES OWNED BY ENERPLUS CORPORATION

Enerplus Resources (USA) Corporation

### LEGAL COUNSEL

Blake, Cassels & Graydon LLP
Calgary, Alberta

### AUDITORS

KPMG LLP
Calgary, Alberta

### TRANSFER AGENT

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

### U.S. CO-TRANSFER AGENT

Computershare Trust Company, N.A.
Golden, Colorado

### INDEPENDENT RESERVE ENGINEERS

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

### STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS

Toronto Stock Exchange: ERF
New York Stock Exchange: ERF

### U.S. OFFICE

950 17th Street, Suite 2200
Denver, Colorado 80202

Telephone: 720.279.5500
Fax: 720.279.5550

# ABBREVIATIONS

| | |
|---|---|
| **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 |

Toll Free 1-800-319-6462
www.enerplus.com
investorrelations@enerplus.com

The Dome Tower
3000, 333-7th Avenue SW
Calgary, Alberta T2P 2Z1

ERF LISTED ON TMX Toronto Stock Exchange

ERF LISTED NYSE