enerPLUS

# Q1 2017 First Quarter Report
Three Months Ended March 31, 2017

## SELECTED FINANCIAL RESULTS

| | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| **Financial (000's)** | | |
| Adjusted Funds Flow[4] | $ 119,920 | $ 41,727 |
| Dividends to Shareholders | 7,242 | 14,464 |
| Net Income/(Loss) | 76,293 | (173,666) |
| Debt Outstanding – net of Cash and Restricted Cash | 350,401 | 992,837 |
| Capital Spending | 120,351 | 43,276 |
| Property and Land Acquisitions | 2,536 | 3,554 |
| Property Divestments | (899) | 187,768 |
| Net Debt to Adjusted Funds Flow Ratio[4] | 0.9x | 2.3x |
| **Financial per Weighted Average Shares Outstanding** | | |
| Net Income/(Loss) | $ 0.32 | $ (0.84) |
| Weighted Average Number of Shares Outstanding (000's) | 241,285 | 206,716 |
| **Selected Financial Results per BOE[1][2]** | | |
| Oil & Natural Gas Sales[3] | $ 36.33 | $ 19.14 |
| Royalties and Production Taxes | (7.89) | (3.95) |
| Commodity Derivative Instruments | 0.86 | 4.45 |
| Cash Operating Expenses | (6.57) | (8.12) |
| Transportation Costs | (3.88) | (2.89) |
| General and Administrative Expenses | (1.87) | (2.07) |
| Cash Share-Based Compensation | (0.02) | (0.08) |
| Interest, Foreign Exchange and Other Expenses | (1.26) | (1.81) |
| Current Income Tax Recovery/(Expense) | (0.01) | 0.02 |
| Adjusted Funds Flow[4] | $ 15.69 | $ 4.69 |

## SELECTED OPERATING RESULTS

| | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| **Average Daily Production[2]** | | |
| Crude Oil (bbls/day) | 33,178 | 39,508 |
| Natural Gas Liquids (bbls/day) | 3,158 | 5,494 |
| Natural Gas (Mcf/day) | 291,607 | 317,150 |
| Total (BOE/day) | 84,937 | 97,860 |
| % Crude Oil and Natural Gas Liquids | 43% | 46% |
| **Average Selling Price [2][3]** | | |
| Crude Oil (per bbl) | $ 57.53 | $ 31.59 |
| Natural Gas Liquids (per bbl) | 37.76 | 11.34 |
| Natural Gas (per Mcf) | 3.63 | 1.77 |
| Net Wells Drilled | 15 | 12 |

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

| Average Benchmark Pricing | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| WTI crude oil (US$/bbl) | $ 51.92 | $ 33.45 |
| AECO natural gas– monthly index (CDN$/Mcf) | 2.94 | 2.11 |
| AECO natural gas – daily index (CDN$/Mcf) | 2.69 | 1.83 |
| NYMEX natural gas – last day (US$/Mcf) | 3.32 | 2.09 |
| USD/CDN average exchange rate | 1.32 | 1.37 |

| Share Trading Summary<br>For the three months ended March 31, 2017 | CDN[1] - ERF<br>(CDN$) | U.S.[2] - ERF<br>(US$) |
|---|---|---|
| High | $ 13.35 | $ 9.95 |
| Low | $ 9.72 | $ 7.26 |
| Close | $ 10.71 | $ 8.05 |

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

| 2017 Dividends per Share | CDN$ | US$[1] |
|---|---|---|
| First Quarter Total | $ 0.03 | $ 0.02 |

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

# NEWS RELEASE

**Highlights:**

- Generated strong adjusted funds flow of $119.9 million
- 24% operating netback improvement quarter-over-quarter
- 18% improvement in realized Bakken differential, 32% improvement in realized Marcellus differential compared to the previous quarter
- Operating expenses of $6.59 per BOE, an 8% reduction quarter-over-quarter
- Completed eight wells at Fort Berthold including three one-mile (short) lateral wells which had an average peak 30-day production rate per well of 1,528 BOE per day
- On track to grow total Company liquids production by 25% from the first quarter of 2017 to the fourth quarter

*"The rate of change in our financial metrics has been significant over the last twelve months,"* stated Ian C. Dundas, President and Chief Executive Officer. *"We continued to focus our portfolio around high-margin, high rate-of-return assets, implement meaningful cost reductions across our business, and strengthen our financial position, while seeing structural improvements to our realized pricing in the Bakken and Marcellus. Our first quarter results demonstrate this step change in the cash flow generating capability and financial sustainability of our business."*

*"We are on track with the execution of our 2017 capital program to deliver strong oil volumes and cash flow growth and are well positioned to drive sustained, long-term profitable growth,"* Dundas added.

**Financial and Operational Summary**

First quarter 2017 production averaged 84,937 BOE per day, including 36,336 barrels per day of crude oil and natural gas liquids. Total production was approximately 5% lower compared to the fourth quarter of 2016 due primarily to the divestment of non-operated North Dakota production in December 2016.

Subsequent to the quarter-end, Enerplus closed the final portion of the previously announced divestment of shallow gas assets in Canada, along with its Brooks waterflood property. The combined production associated with these divestments was approximately 7,300 BOE per day, of which 1,700 BOE per day closed during the first quarter, with the remaining 5,600 BOE per day having closed subsequent to the quarter-end.

Production in the Williston Basin began building momentum towards the end of the first quarter as the majority of wells completed during the quarter were brought on-stream in the latter half. Williston Basin production averaged 25,065 BOE per day during the quarter, with March production of approximately 27,000 BOE per day. Enerplus is well positioned to drive strong oil production growth through the year and achieve its fourth quarter total Company liquids production guidance of 43,000 to 48,000 barrels per day.

Enerplus generated first quarter 2017 adjusted funds flow of $119.9 million, an 11% increase from the previous quarter. The strong adjusted funds flow was a result of Enerplus' continued netback expansion from a combination of reductions to the Company's cost structure and improving realized pricing in the Bakken and Marcellus. Enerplus' first quarter 2017 operating netback, before hedging, was $17.99 per BOE, a 24% increase relative to the fourth quarter of 2016.

Enerplus' commodity hedging program realized cash gains of $6.6 million in the first quarter of 2017. The Company realized cash losses of $1.0 million on its crude oil contracts and cash gains of $7.6 million on its natural gas contracts, including unwinding a portion of its AECO-NYMEX basis physical contracts in connection with the previously announced sale of Canadian shallow gas properties.

Pricing dynamics in the Bakken and Marcellus have continued to improve with the buildout of pipeline infrastructure in both regions. Enerplus' realized Bakken crude oil price differential averaged US$5.59 per barrel below WTI in the first quarter of 2017, an 18% improvement relative to the previous quarter. Enerplus' realized Marcellus natural gas sales price differential averaged US$0.60 per Mcf below NYMEX in the first quarter of 2017, a 32% improvement relative to the previous quarter.

Enerplus has continued to reduce its operating expenses through savings from divesting higher cost assets and continuing to optimize its operating processes. First quarter 2017 operating expenses averaged $6.59 per BOE, 8% lower compared to the prior quarter. As a result, Enerplus is lowering its 2017 operating expense guidance to $6.85 per BOE, from $7.25 per BOE. Enerplus expects operating costs to increase during the second half of 2017 as a result of the increasing liquids production and scheduled turnarounds in Canada.

Transportation costs in the first quarter of 2017 averaged $3.88 per BOE, an increase from $3.44 per BOE in the fourth quarter of 2016. The increase in transportation cost per BOE is primarily due to the divestment of non-operated North Dakota volumes at the end of 2016, and higher Marcellus production in the first quarter of 2017.

Cash G&A expenses were $1.87 per BOE in the first quarter of 2017, compared to $1.63 per BOE in the previous quarter. The increase in cash G&A expenses per BOE was largely due to the lower production volumes in the first quarter of 2017.

Enerplus remains in a strong financial position. Total debt net of cash and restricted cash at March 31, 2017 was $350.4 million. Total debt was comprised of $4.0 million drawn on the Company's $800 million bank credit facility, and $740.0 million of senior notes outstanding. Enerplus' cash balance was $393.6 million, including restricted cash. At March 31, 2017, Enerplus' net debt to adjusted funds flow ratio was 0.9 times.

Exploration and development capital spending in the first quarter of 2017 was $120.4 million, with $85.1 million directed to North Dakota, $25.1 million directed to the Canadian waterfloods, and $9.8 million directed to the Marcellus. Enerplus' 2017 exploration and development capital budget of $450 million is unchanged.

### Average Daily Production[(1)]

| | Three months ended March 31, 2017 | | |
|---|---|---|---|
| | **Crude Oil and NGL** (Mbbl/day) | **Natural Gas** (MMcf/day) | **Total** (Mboe/day) |
| Williston Basin | 22.0 | 18.3 | 25.1 |
| Marcellus | — | 204.8 | 34.1 |
| Canadian Waterfloods[(2)] | 13.0 | 20.8 | 16.4 |
| Other[(2)] | 1.3 | 47.8 | 9.3 |
| **Total** | **36.3** | **291.6** | **84.9** |

(1) Table may not add due to rounding.
(2) First quarter production includes volumes from Canadian properties that were divested during and subsequent to the quarter.

### Summary of Wells Brought On-Stream

| | Three months ended March 31, 2017 | | | |
|---|---|---|---|---|
| | **Operated** | | **Non Operated** | |
| | Gross | Net | Gross | Net |
| Williston Basin | 8.0 | 6.7 | — | — |
| Marcellus | — | — | 9.0 | 0.8 |
| Canadian Waterfloods | 2.0 | 2.0 | — | — |
| **Total** | **10.0** | **8.7** | **9.0** | **0.8** |

### Asset Activity

WILLISTON BASIN

Williston Basin production averaged 25,065 BOE per day (88% liquids) during the first quarter of 2017, a 22% decrease compared to the fourth quarter of 2016 largely due to the Company's divestment of non-operated North Dakota production in December 2016. First quarter Williston Basin production was comprised of 20,842 BOE per day in North Dakota and 4,223 BOE per day in Montana.

During the first quarter of 2017, Enerplus completed and brought on-stream eight gross operated wells (84% average working interest) at Fort Berthold. On the Elements pad, Enerplus completed a two-mile lateral Middle Bakken well that had a peak 30-day production rate of 1,723 BOE per day. On the Cactus pad, Enerplus completed four two-mile lateral wells (three Middle Bakken, one Three Forks) that had extended cleanout operations impacting initial production rates. The wells established an average peak 30-day production rate per well of 1,111 BOE per day. Enerplus completed three one-mile lateral wells (two Middle Bakken, one Three Forks) that had an average peak 30-day production rate per well of 1,528 BOE per day.

Enerplus added a second operated drilling rig at Fort Berthold in January 2017. The Company drilled seven gross operated wells in the first quarter. Current gross Enerplus operated drilled and completed well costs for a two-mile lateral, assuming Enerplus' base completion design of 1,000 pounds of proppant per lateral foot, are US$6.7 million, with associated facilities costs of US$1.1 million per well.

Bakken price differentials have continued to strengthen over the past year due to regional production declines, strong regional demand, and the anticipated start-up of the Dakota Access Pipeline project in the second quarter of 2017. This project will result in regional pipeline capacity exceeding current production levels and is expected to support stronger Bakken prices going forward. Enerplus' realized Bakken crude oil price differential averaged US$5.59 per barrel below WTI in the first quarter of 2017, an 18% improvement relative to the fourth quarter of 2016. Enerplus continues to expect its Bakken crude oil differential to average approximately US$4.50 per barrel below WTI during 2017.

MARCELLUS

Marcellus production averaged 205 MMcf per day during the first quarter of 2017, a 7% increase compared to the previous quarter. Improving regional natural gas prices in the Marcellus have led to an increase in activity levels compared to 2016. Enerplus participated in nine gross non-operated wells (9% average working interest) that were brought on-stream during the first quarter of 2017. Six of these wells had more than 30 days on production as of the date of this news release with an average lateral length of 6,100 feet per well and an average peak 30-day production rate per well of 18.8 MMcf per day.

The Company participated in drilling 10 gross non-operated wells (17% average working interest) during the first quarter.

Enerplus' realized Marcellus sales price differential, excluding transportation and gathering, averaged US$0.60 per Mcf below NYMEX during the first quarter of 2017. Continued growth in regional natural gas power plant demand and the steady addition of new pipeline projects in 2016 has resulted in demand exceeding supply in the Northeast U.S. This has resulted in much stronger regional natural gas prices relative to prior periods. Enerplus estimates that the Northeast Pennsylvania region currently has excess egress pipeline capacity, and with additional infrastructure expected to be brought online over the next few years, Enerplus expects Marcellus price differentials will continue to remain strong in 2017 and improve further into 2018. As a result, Enerplus now expects its Marcellus natural gas realized price differential to average US$0.60 per Mcf below NYMEX during 2017.

CANADIAN WATERFLOODS

Canadian waterflood production averaged 16,438 BOE per day (79% liquids) during the first quarter of 2017, an increase of 4% from the previous quarter largely due to Ante Creek volumes which were acquired midway through the fourth quarter of 2016. First quarter volumes include production from the Brooks asset which was divested subsequent to the quarter-end. Excluding Brooks volumes, Canadian waterflood production averaged 13,570 BOE per day (80% liquids) during the first quarter.

Activity at Ante Creek was focused on expanding the supply of source water for injection, and optimizing facilities in preparation for increasing water injection. Other activity in the quarter was focused in Southeast Saskatchewan and at Cadogan where the Company drilled nine gross wells including two injector wells. The drilling programs were completed on time and budget with initial well results meeting or exceeding type curve expectations.

**Risk Management**

Enerplus continues to manage risk through commodity hedging. Using swaps and collar structures, Enerplus has an average of 18,680 barrels per day of crude oil protected for the remainder of 2017 (approximately 69% of forecast crude oil production net of royalties), 12,500 barrels per day of crude oil protected in 2018, and 4,000 barrels per day of crude oil protected in 2019.

For natural gas, Enerplus has 50,000 Mcf per day protected for the remainder of 2017 (approximately 25% of forecast natural gas production net of royalties) using collar structures.

**Commodity Hedging Detail (As at May 4, 2017)**

| | WTI Crude Oil (US$/bbl) | | | | | NYMEX Natural Gas (US$/Mcf) |
|---|---|---|---|---|---|---|
| | Apr 1, 2017 – Jun 30, 2017 | Jul 1, 2017 – Dec 31, 2017 | Jan 1, 2018 – Dec 31, 2018 | Jan 1, 2019 – Mar 31, 2019 | Apr 1, 2019 – Dec 31, 2019 | Apr 1, 2017 – Dec 31, 2017 |
| **Swaps** | | | | | | |
| Sold Swaps | $ 53.50 | $ 53.50 | $ 53.73 | $ 53.73 | $ — | $ — |
| Volume (bbls/day or Mcf/day) | 2,000 | 2,000 | 3,000 | 3,000 | — | — |
| **Three Way Collars** | | | | | | |
| Sold Puts | $ 38.94 | $ 39.62 | $ 43.13 | $ 45.00 | $ 43.75 | $ 2.06 |
| Volume (bbls/day or Mcf/day) | 14,000 | 18,000 | 9,500 | 1,000 | 4,000 | 50,000 |
| Purchased Puts | $ 50.29 | $ 50.61 | $ 54.00 | $ 56.00 | $ 54.69 | $ 2.75 |
| Volume (bbls/day or Mcf/day) | 14,000 | 18,000 | 9,500 | 1,000 | 4,000 | 50,000 |
| Sold Calls | $ 61.14 | $ 60.33 | $ 63.09 | $ 70.00 | $ 66.18 | $ 3.41 |
| Volume (bbls/day or Mcf/day) | 14,000 | 18,000 | 9,500 | 1,000 | 4,000 | 50,000 |

## 2017 Updated Guidance

Enerplus is reducing its 2017 operating expense guidance to $6.85 per BOE from $7.25 per BOE and narrowing its expected 2017 average Marcellus differential to US$0.60 per Mcf below NYMEX from US$0.90 per Mcf below NYMEX. All other guidance is unchanged.

| | Guidance |
|---|---|
| Capital spending | $450 million |
| Average annual production | 81,000 – 85,000 BOE/day |
| Fourth quarter average production | 86,000 – 91,000 BOE/day |
| Average annual crude oil and natural gas liquids production | 38,500 – 41,500 barrels/day |
| Fourth quarter average crude oil and natural gas liquids production | 43,000 – 48,000 barrels/day |
| Average royalty and production tax rate | 24% |
| Operating expense | $6.85/BOE (from $7.25/BOE) |
| Transportation expense | $4.00/BOE |
| Cash G&A expense | $1.85/BOE |

| **Differential/Basis Outlook**[(1)] | |
|---|---|
| 2017 Average U.S. Bakken crude oil differential (compared to WTI crude oil) | US$(4.50)/bbl |
| 2017 Average Marcellus natural gas sales price differential (compared to NYMEX natural gas) | US$(0.60)/Mcf (from US$(0.90)/Mcf) |

(1) Excluding transportation costs.

*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 gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs. BOEs may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading.*

*Presentation of Production Information*

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

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

**Forward-Looking Information and Statements**

*This news release contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "should", "believe", "plans", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this news release contains forward-looking information pertaining to the following: expected average production volumes in 2017 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 differentials and our commodity risk management programs in 2017 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 2017 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 2017 guidance contained in this news release is based on the following: a WTI price of US$55.00/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.75/GJ and a USD/CDN exchange rate of 1.35. 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 future decline, 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 and Form 40-F at December 31, 2016).*

**Non-GAAP Measures**

*In this news release, we use the terms "adjusted funds flow" and "net debt to adjusted funds flow ratio" as measures to analyze operating performance, leverage and liquidity. "Adjusted funds flow" is calculated as net cash generated from operating activities but before changes in non-cash operating working capital and asset retirement obligation expenditures. "Net debt to adjusted funds flow ratio" is calculated as total debt net of cash and restricted cash, divided by a trailing 12 months of adjusted funds flow. Calculation of these terms is described in Enerplus' MD&A under the "Liquidity and Capital Resources" section.*

*Enerplus believes that, in addition to net earnings and other measures prescribed by U.S. GAAP, the terms "adjusted funds flow" and "net debt to adjusted funds flow" are useful supplemental measures as they provide an indication of the results generated by Enerplus' principal business activities. However, these measures are not measures recognized by U.S. GAAP and do not have a standardized meaning prescribed by U.S.GAAP. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers. For reconciliation of these measures to the most directly comparable measure calculated in accordance with U.S. GAAP, and further information about these measures, see disclosure under "Non-GAAP Measures" in Enerplus' First Quarter 2017 MD&A.*

Electronic copies of Enerplus Corporation's First Quarter 2017 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 our audited financial statements at any time. For further information, please contact Investor Relations at 1-800-319-6462 or email investorrelations@enerplus.com.

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

The following discussion and analysis of financial results is dated May 5, 2017 and is to be read in conjunction with:

- the unaudited interim consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three months ended March 31, 2017 and 2016 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015 and 2014; and
- our MD&A for the year ended December 31, 2016 (the "Annual MD&A").

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information. The following MD&A also contains financial measures that do not have a standardized meaning as prescribed by accounting principles generally accepted in the United States of America ("U.S. GAAP"). See "Non-GAAP Measures" at the end of the MD&A for further information.

**BASIS OF PRESENTATION**

The Interim Financial Statements and notes have been prepared in accordance with U.S. GAAP, including the prior period comparatives. All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included in the Interim Financial Statements.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. 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 peers.

**OVERVIEW**

Average daily production for the first quarter was 84,937 BOE/day, in line with our annual average production guidance range of 81,000 – 85,000 BOE/day. Production decreased 5% or 4,023 BOE/day from the fourth quarter of 2016 largely due to lower crude oil and liquids volumes following the December 30, 2016 sale of our non-operated North Dakota properties with production of approximately 5,000 BOE/day. The decrease in crude oil and liquids volume was offset by higher natural gas production from the Marcellus due to improved realized pricing. We are maintaining our annual average production guidance of 81,000 – 85,000 BOE/day, including approximately 38,500 – 41,500 bbls/day of crude oil and natural gas liquids. We continue to expect our average daily production and crude oil and liquids weighting to increase in the second half of the year as a result of significant capital spending in North Dakota, with expected fourth quarter average daily production of 86,000 – 91,000 BOE/day, including 43,000 – 48,000 bbls/day of crude oil and natural gas liquids.

Our capital spending for the first quarter was $120.4 million, in line with our expectation. Approximately 70% of spending directed to our North Dakota crude oil properties and 21% directed to our Canadian crude oil assets. We are maintaining our 2017 annual capital spending guidance of $450 million.

Operating expenses for the first quarter came in below annual guidance of $7.25/BOE, totaling $50.3 million or $6.59/BOE. The decrease in operating costs was mainly due to additional savings related to our previously announced Canadian non-core asset divestments, as well as lower than expected activity levels. As a result, we are reducing our annual guidance for operating expenses to $6.85/BOE from $7.25/BOE. Cash G&A expenses for the first quarter were $14.3 million or $1.87/BOE compared to annual guidance of $1.85/BOE. We are maintaining our cash G&A guidance of $1.85/BOE.

Our commodity hedging program continued to provide funds flow protection, contributing cash gains of $6.6 million in the first quarter. Since the prior quarter, we have added to our commodity hedge positions. As of May 4, 2017, we have approximately 69% of our forecasted crude oil production, net of royalties, hedged in 2017, and approximately 46% and 15% of our crude oil production, net of royalties, hedged in 2018 and 2019, respectively, based on 2017 forecasted production. We have also hedged approximately 25% of our forecasted natural gas production, net of royalties, in 2017. At March 31, 2017, the fair value of our crude oil and natural gas hedging contracts were in a net asset position of $12.7 million (December 31, 2016 - net liability of $38.3 million).

We recorded net income of $76.3 million and adjusted funds flow of $119.9 million in the first quarter, compared to $840.3 million and $107.7 million, respectively, in the fourth quarter of 2016. Both net income and adjusted funds flow benefited from improved pricing which offset the impact of reduced volumes, as well as an $8.8 million or 15% reduction in cash operating expenses.

At March 31, 2017, our total debt net of cash and restricted cash was $350.4 million and our net debt to adjusted funds flow ratio was 0.9x.

Subsequent to the first quarter, we closed the final portion of our previously announced Canadian divestment for proceeds of $60.8 million, after closing adjustments. Including the portion of the deal which closed in March 2017, the divested properties include the majority of our shallow gas assets as well as our Brooks waterflood property. These properties had combined production of approximately 7,300 BOE/day and accounted for $64.6 million of our future asset retirement obligation.

## RESULTS OF OPERATIONS

### Production

Average daily production for the first quarter totaled 84,937 BOE/day, in line with our annual average guidance range of 81,000 – 85,000 BOE/day. Compared to production in the fourth quarter of 2016 of 88,960 BOE/day, production decreased by 5% or 4,023 BOE/day. Crude oil and liquids production decreased by 5,200 BOE/day primarily due to the December 30, 2016 sale of our non-operated North Dakota properties with production of approximately 5,000 BOE/day (90% crude oil and liquids). Natural gas production increased 2% over the same period primarily due to higher production in the Marcellus as a result of improved realized prices.

Production in the first quarter of 2017 decreased by 13% from production levels of 97,860 BOE/day during the same period of the prior year primarily due to the sale of non-core properties throughout 2016 with production of approximately 13,500 BOE/day. With the exception of the North Dakota non-operated sale, divested volumes related to Canadian non-core assets (86% natural gas). Production levels compared to the prior period were also impacted by reduced capital spending throughout 2016.

Our crude oil and natural gas liquids production weighting decreased to 43% in the first quarter of 2017 compared to 46% in the same period of 2016 primarily due to the North Dakota non-operated divestment.

Average daily production volumes for the three months ended March 31, 2017 and 2016 are outlined below:

| | Three months ended March 31, | | |
|---|---|---|---|
| **Average Daily Production Volumes** | **2017** | **2016** | **% Change** |
| Crude oil (bbls/day) | 33,178 | 39,508 | (16%) |
| Natural gas liquids (bbls/day) | 3,158 | 5,494 | (43%) |
| Natural gas (Mcf/day) | 291,607 | 317,150 | (8%) |
| Total daily sales (BOE/day) | 84,937 | 97,860 | (13%) |

We are maintaining our annual average production guidance of 81,000 – 85,000 BOE/day and our crude oil and natural gas liquids guidance of 38,500 – 41,500 bbls/day. This guidance includes the impact of our recently announced divestment of shallow gas assets and our Brooks waterflood property with production of approximately 7,300 BOE/day. We continue to expect our average daily production and crude oil and liquids weighting to increase in the second half of the year as a result of significant capital spending in North Dakota, with fourth quarter average daily production expected to be between 86,000 – 91,000 BOE/day, including 43,000 – 48,000 bbls/day of crude oil and natural gas liquids.

### 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 quarter of 2017 to the previous four quarters:

| **Pricing** (average for the period) | Q1 2017 | Q4 2016 | Q3 2016 | Q2 2016 | Q1 2016 |
|---|---|---|---|---|---|
| **Benchmarks** | | | | | |
| WTI crude oil (US$/bbl) | $ 51.92 | $ 49.29 | $ 44.94 | $ 45.59 | $ 33.45 |
| AECO natural gas – monthly index ($/Mcf) | 2.94 | 2.81 | 2.20 | 1.25 | 2.11 |
| AECO natural gas – daily index ($/Mcf) | 2.69 | 3.09 | 2.32 | 1.40 | 1.83 |
| NYMEX natural gas – last day (US$/Mcf) | 3.32 | 2.98 | 2.81 | 1.95 | 2.09 |
| USD/CDN average exchange rate | 1.32 | 1.33 | 1.31 | 1.29 | 1.37 |
| USD/CDN period end exchange rate | 1.33 | 1.34 | 1.31 | 1.30 | 1.30 |
| **Enerplus selling price**(1) | | | | | |
| Crude oil ($/bbl) | $ 57.53 | $ 53.91 | $ 47.93 | $ 46.48 | $ 31.59 |
| Natural gas liquids ($/bbl) | 37.76 | 21.31 | 13.85 | 15.67 | 11.34 |
| Natural gas ($/Mcf) | 3.63 | 2.89 | 2.12 | 1.49 | 1.77 |
| **Average differentials** | | | | | |
| MSW Edmonton – WTI (US$/bbl) | $ (3.54) | $ (3.11) | $ (2.96) | $ (3.09) | $ (3.69) |
| WCS Hardisty – WTI (US$/bbl) | (14.58) | (14.32) | (13.50) | (13.30) | (14.24) |
| Transco Leidy monthly – NYMEX (US$/Mcf) | (0.63) | (1.58) | (1.35) | (0.70) | (0.99) |
| TGP Z4 300L monthly – NYMEX (US$/Mcf) | (0.70) | (1.64) | (1.40) | (0.73) | (1.07) |
| AECO monthly – NYMEX (US$/Mcf) | (1.10) | (0.86) | (1.13) | (0.99) | (0.56) |
| **Enerplus realized differentials** (1) | | | | | |
| Canada crude oil – WTI (US$/bbl) | $ (12.76) | $ (12.97) | $ (12.06) | $ (12.01) | $ (14.14) |
| Canada natural gas – NYMEX (US$/Mcf) | (0.56) | (0.63) | (0.92) | (0.86) | (0.63) |
| Bakken crude oil – WTI (US$/bbl) | (5.59) | (6.80) | (6.39) | (8.23) | (8.38) |
| Marcellus natural gas – NYMEX (US$/Mcf) | (0.60) | (0.88) | (1.19) | (0.76) | (0.91) |

(1) Excluding transportation costs, royalties and commodity derivative instruments.

CRUDE OIL AND NATURAL GAS LIQUIDS

Our average realized crude oil price during the quarter increased by 7% to $57.53/bbl, compared to a 5% increase in benchmark WTI prices. This increase was led mostly by stronger Bakken price differentials which improved by 18% during the quarter to average US$5.59/bbl below WTI. Bakken prices have continued to strengthen over the past year due to regional production declines, strong regional demand and the anticipated start-up of the Dakota Access Pipeline project in the second quarter of 2017. This project will result in regional pipeline capacity exceeding current production levels and should support stronger Bakken prices going forward. We continue to expect our Bakken crude oil differential to average US$4.50/bbl below WTI for all of 2017.

Our realized price differential for our Canadian crude oil production improved by 2% during the quarter compared to the previous quarter, due largely to our acquisition of a Canadian light crude oil waterflood property during November 2016.

Our realized price for natural gas liquids averaged $37.76/bbl during the quarter, an improvement of 77% compared to the fourth quarter of 2016, due to improvements in the underlying benchmark pricing as the supply-demand balance for natural gas liquids has improved.

NATURAL GAS

Our realized natural gas price during the first quarter improved by 26% compared to the fourth quarter of 2016 to average $3.63/Mcf. Benchmark NYMEX natural gas prices improved by 11% during the quarter, due to lower U.S. production and weather related demand increases in key regions of the U.S. through the latter part of the quarter.

Our realized Marcellus sales price differential excluding transportation and gathering improved by 32% during the quarter to average US$0.60/Mcf below NYMEX. Benchmark monthly Transco Leidy prices averaged US$0.63/Mcf below NYMEX during the first quarter. Continued growth in regional natural gas power plant demand and the steady addition of new pipeline projects in 2016 has resulted in demand exceeding supply in Northeast Pennsylvania. Our view remains that the Marcellus currently has excess pipeline capacity, and given the amount of additional infrastructure expected to be brought online over the next few years, we expect Marcellus price differentials to continue to strengthen into 2018. We now expect our Marcellus natural gas realized price differential to average US$0.60/Mcf below NYMEX during 2017.

Most of our Canadian gas production is sold under multi-year fixed AECO basis differential contracts at prices better than those currently realized in the spot market. Our realized Canadian gas price differential averaged US$0.56/Mcf below NYMEX compared to the AECO benchmark monthly price that averaged US$1.10/Mcf below NYMEX in the first quarter.

FOREIGN EXCHANGE

The USD/CDN exchange rate was 1.33 USD/CDN at March 31, 2017, and averaged 1.32 USD/CDN during the first quarter of 2017 compared to 1.33 USD/CDN during the fourth quarter of 2016. The majority of our oil and natural gas sales are based on U.S. dollar denominated indices, and a weaker Canadian dollar relative to the U.S. dollar increases the amount of our realized sales. Because we report in Canadian dollars, the fluctuations in the Canadian dollar also impact our U.S. dollar denominated costs, capital spending and the reported value of our U.S. dollar denominated debt.

**Price Risk Management**

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

As of May 4, 2017, we have hedged approximately 18,680 bbls/day of our crude oil production for the remainder of 2017, which represents approximately 69% of our forecasted crude oil production, after royalties. For 2018, we have hedged 12,500 bbls/day, which represents approximately 46% of our 2017 forecasted crude oil production, after royalties. For 2019, we have hedged 4,000 bbls/day, which represents approximately 15% of our 2017 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 over the contract term, 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 adjusted funds flow.

As of May 4, 2017, we have hedged approximately 50,000 Mcf/day of our natural gas production for the remainder of 2017 using NYMEX three way collars. This represents approximately 25% of our forecasted natural gas production, after royalties. When NYMEX prices settle below the sold put strike price over the contract term, the three way collars provide a limited amount of protection above the NYMEX index prices equal to the difference between the strike price of the purchased and sold puts.

The following is a summary of our financial contracts in place at May 4, 2017, expressed as a percentage of our 2017 net production volumes:

| | WTI Crude Oil (US$/bbl)(1) | | | | | NYMEX Natural Gas (US$/Mcf)(1) |
|---|---|---|---|---|---|---|
| | Apr 1, 2017 – Jun 30, 2017 | Jul 1, 2017 – Dec 31, 2017 | Jan 1, 2018 – Dec 31, 2018 | Jan 1, 2019 – Mar 31, 2019 | Apr 1, 2019 – Dec 31, 2019 | Apr 1, 2017 – Dec 31, 2017 |
| **Swaps** | | | | | | |
| Sold Swaps | $ 53.50 | $ 53.50 | $ 53.73 | $ 53.73 | — | — |
| % | 7% | 7% | 11% | 11% | — | — |
| **Three Way Collars** | | | | | | |
| Sold Puts | $ 38.94 | $ 39.62 | $ 43.13 | $ 45.00 | $ 43.75 | $ 2.06 |
| % | 52% | 67% | 35% | 4% | 15% | 25% |
| Purchased Puts | $ 50.29 | $ 50.61 | $ 54.00 | $ 56.00 | $ 54.69 | $ 2.75 |
| % | 52% | 67% | 35% | 4% | 15% | 25% |
| Sold Calls | $ 61.14 | $ 60.33 | $ 63.09 | $ 70.00 | $ 66.18 | $ 3.41 |
| % | 52% | 67% | 35% | 4% | 15% | 25% |

(1) Based on weighted average price (before premiums) assuming average annual production of 83,000 BOE/day less royalties and production taxes of 24%.

ACCOUNTING FOR PRICE RISK MANAGEMENT

| **Commodity Risk Management Gains/(Losses)** | **Three months ended March 31,** | |
|---|---|---|
| ($ millions) | **2017** | **2016** |
| Cash gains/(losses): | | |
| Crude oil | $ (1.0) | $ 36.6 |
| Natural gas | 7.6 | 3.0 |
| Total cash gains/(losses) | $ 6.6 | $ 39.6 |
| Non-cash gains/(losses): | | |
| Crude oil | $ 44.4 | $ (31.2) |
| Natural gas | 6.6 | 5.1 |
| Total non-cash gains/(losses) | $ 51.0 | $ (26.1) |
| Total gains/(losses) | $ 57.6 | $ 13.5 |

| | **Three months ended March 31,** | |
|---|---|---|
| (Per BOE) | **2017** | **2016** |
| Total cash gains/(losses) | $ 0.86 | $ 4.45 |
| Total non-cash gains/(losses) | 6.67 | (2.94) |
| Total gains/(losses) | $ 7.53 | $ 1.51 |

During the first quarter of 2017 we realized cash losses of $1.0 million on our crude oil contracts and cash gains of $7.6 million on our natural gas contracts. In comparison, during the first quarter of 2016 we realized cash gains of $36.6 million on our crude oil contracts and $3.0 million on our natural gas contracts. Cash gains recorded in the quarter on our natural gas contracts included a gain of $8.5 million on the unwind of a portion of our AECO-NYMEX basis physical contracts in conjunction with the sale of our Canadian non-core natural gas properties. Cash losses on crude oil contracts were primarily due to premiums paid on our three way collars.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At the end of the first quarter of 2017, the fair value of our crude oil contracts was in a net asset position of $15.5 million, while the fair value of our natural gas contracts was in a net liability position of $2.8 million. For the three months ended March 31, 2017, the change in the fair value of our crude oil and natural gas contracts represented gains of $44.4 million and $6.6 million, respectively.

**Revenues**

| | **Three months ended March 31,** | |
|---|---|---|
| ($ millions) | **2017** | **2016** |
| Oil and natural gas sales | $ 277.7 | $ 170.5 |
| Royalties | (49.9) | (27.8) |
| Oil and natural gas sales, net of royalties | $ 227.8 | $ 142.7 |

Oil and natural gas sales for the three months ended March 31, 2017 were $277.7 million, an increase of 63% from the same period in 2016. The increase in revenue during the first quarter was primarily a result of higher commodity pricing compared to the same period in 2016, which more than offset the impact of lower production.

### Royalties and Production Taxes

| ($ millions, except per BOE amounts) | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| Royalties | $ 49.9 | $ 27.8 |
| Per BOE | $ 6.53 | $ 3.12 |
| Production taxes | $ 10.4 | $ 7.4 |
| Per BOE | $ 1.36 | $ 0.83 |
| Royalties and production taxes | $ 60.3 | $ 35.2 |
| Per BOE | $ 7.89 | $ 3.95 |
| Royalties and production taxes (% of oil and natural gas sales) | 22% | 21% |

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges. A large percentage of our production is from U.S. properties where royalty rates are generally less sensitive to commodity price levels. During the three months ended March 31, 2017, royalties and production taxes increased to $60.3 million, from $35.2 million for the same period in 2016 primarily due to higher commodity prices. Royalties and production taxes averaged 22% of oil and natural gas sales before transportation costs in the first quarter of 2017 compared to 21% for the same period in 2016 due to a greater portion of our production coming from our U.S. properties with higher overall royalty rates. Alberta’s Modernized Royalty Framework, which came into effect on January 1, 2017, has not had a significant impact on our Canadian royalties.

We are maintaining our average royalty and production tax rate guidance of 24% in 2017. We continue to expect our royalty rate to increase in the latter half of the year as a result of a higher U.S. production weighting.

### Operating Expenses

| ($ millions, except per BOE amounts) | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| Cash operating expenses | $ 50.3 | $ 72.3 |
| Non-cash (gains)/losses(1) | 0.1 | 0.3 |
| Total operating expenses | $ 50.4 | $ 72.6 |
| Per BOE | $ 6.59 | $ 8.15 |

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

Operating expenses for the first quarter of 2017 totaled $50.4 million or $6.59/BOE, below our annual guidance of $7.25/BOE. Operating costs decreased by 31% from $72.6 million or $8.15/BOE during the same period of the prior year due to the divestment of higher operating cost Canadian properties throughout 2016, along with lower repairs and maintenance, fluid handling and gas facility charges compared to the prior period.

During the first quarter of 2017, we realized additional savings from our previously announced non-core divestments and cost reductions due to lower than expected activity levels. As a result, we are lowering our 2017 guidance for operating expenses to $6.85/BOE from $7.25/BOE. Although our operating costs were below guidance during the first quarter, we expect costs to increase on a per BOE basis during the second half of the year with our higher liquids weighting and scheduled turnarounds in Canada.

### Transportation Costs

| ($ millions, except per BOE amounts) | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| Transportation costs | $ 29.6 | $ 25.7 |
| Per BOE | $ 3.88 | $ 2.89 |

For the three months ended March 31, 2017, transportation costs were $29.6 million or $3.88/BOE, below our annual guidance of $4.00/BOE. Transportation costs have increased by $3.9 million from $25.7 million or $2.89/BOE during the same period in 2016. The increase in the cost per BOE is primarily due to additional firm transportation commitments, including 30,000 Mcf/day of additional interstate pipeline capacity from the Marcellus region to downstream connections that came into effect in August 2016.

We are maintaining our 2017 guidance for transportation costs of $4.00/BOE, as our growing U.S. production volumes have higher associated transportation costs.

**Netbacks**

The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section of this MD&A.

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

| | Three months ended March 31, 2016 | | |
|---|---|---|---|
| **Netbacks by Property Type** | **Crude Oil** | **Natural Gas** | **Total** |
| Average Daily Production | 48,280 BOE/day | 297,480 Mcfe/day | 97,860 BOE/day |
| Netback[1] $ per BOE or Mcfe | (per BOE) | (per Mcfe) | (per BOE) |
| Oil and natural gas sales | $ 27.54 | $ 1.83 | $ 19.14 |
| Royalties and production taxes | (6.43) | (0.26) | (3.95) |
| Cash operating expenses | (10.17) | (1.02) | (8.12) |
| Transportation costs | (1.87) | (0.65) | (2.89) |
| Netback before hedging | $ 9.07 | $ (0.10) | $ 4.18 |
| Cash gains/(losses) | 8.32 | 0.11 | 4.45 |
| Netback after hedging | $ 17.39 | $ 0.01 | $ 8.63 |
| Netback before hedging ($ millions) | $ 39.9 | $ (2.6) | $ 37.3 |
| Netback after hedging ($ millions) | $ 76.5 | $ 0.4 | $ 76.9 |

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

Crude oil and natural gas netbacks per BOE after hedging were higher for the three months ended March 31, 2017 compared to the same period in 2016 primarily due to significantly higher oil and natural gas sales as a result of improvements in commodity prices and differentials in North Dakota and Marcellus regions, along with reductions to our operating expenses. In 2017, our crude oil properties accounted for 63% of our netback before hedging compared to 100% of our netback during the first quarter of 2016.

## 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 10 and Note 13 to the Interim Financial Statements for further details.

| | Three months ended March 31, | |
|---|---|---|
| ($ millions) | 2017 | 2016 |
| Cash: | | |
| G&A expense | $ 14.3 | $ 18.4 |
| Share-based compensation expense | 0.2 | 0.7 |
| Non-Cash: | | |
| Share-based compensation expense | 8.1 | 3.4 |
| Equity swap loss/(gain) | 0.9 | (0.1) |
| Total G&A expenses | $ 23.5 | $ 22.4 |

| | Three months ended March 31, | |
|---|---|---|
| (Per BOE) | 2017 | 2016 |
| Cash: | | |
| G&A expense | $ 1.87 | $ 2.07 |
| Share-based compensation expense | 0.02 | 0.08 |
| Non-Cash: | | |
| Share-based compensation expense | 1.06 | 0.39 |
| Equity swap loss/(gain) | 0.12 | (0.02) |
| Total G&A expenses | $ 3.07 | $ 2.52 |

For the three months ended March 31, 2017, cash G&A expenses were $14.3 million or $1.87/BOE, in line with our annual guidance of $1.85/BOE. The decrease in cash G&A expenses from $18.4 million or $2.07/BOE in the same period in 2016 was primarily due to continued cost savings initiatives and the impact of reductions in staff levels throughout 2016 as we continue to divest of non-core properties and focus our business.

During the quarter, we reported cash SBC expense of $0.2 million or $0.02/BOE, a decrease of 71% compared to $0.7 million or $0.08/BOE during the same period in 2016. During the first quarter of 2016, we recorded expenses related to our Director Share Unit ("DSU") plan and the final settlement of our cash-settled Restricted Share Unit ("RSU") plan, while the current quarter expense relates solely to the annual grant of our DSU plan offset by the impact of a lower share price on outstanding units. Our DSU plan is the only remaining LTI plan that we intend to settle in cash. We recorded non-cash SBC of $8.1 million or $1.06/BOE in the first quarter of 2017 compared to $3.4 million or $0.39/BOE during the same period in 2016. The increase in non-cash SBC was a result of an improvement in our performance multiplier based on our relative return in the Toronto Stock Exchange Oil and Gas Producers Index.

We have hedges in place on the outstanding cash-settled grants under our LTI plans. In the first quarter we recorded a non-cash mark-to-market loss of $0.9 million on these hedges. As of March 31, 2017 we had 470,000 units hedged at a weighted average price of $16.89 per share.

We are maintaining our cash G&A guidance of $1.85/BOE.

## Interest Expense

For the three months ended March 31, 2017, we recorded total interest expense of $10.1 million, compared to $14.5 million for the same period in 2016. The decrease in interest expense corresponds to a decrease in the aggregate principal amount of our outstanding senior notes following our repurchase of US$267 million of senior notes during the first half of 2016, along with a decrease in our drawn bank credit facility compared to the same period in 2016.

At March 31, 2017, we were essentially undrawn on our $800 million bank credit facility, and our debt balance consisted primarily of fixed interest rate senior notes with a weighted average interest rate of 5.0%. See Note 7 in the Interim Financial Statements for further details.

### Foreign Exchange

| ($ millions) | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| Realized loss/(gain) | $ 0.1 | $ 1.8 |
| Unrealized loss/(gain) | (3.9) | (56.2) |
| Total foreign exchange loss/(gain) | $ (3.8) | $ (54.4) |
| USD/CDN average exchange rate | 1.32 | 1.37 |
| USD/CDN period end exchange rate | 1.33 | 1.30 |

For the three months ended March 31, 2017, we recorded a net foreign exchange gain of $3.8 million, compared to a gain of $54.4 million for the same period in 2016. Realized gains and losses relate primarily to day-to-day transactions recorded in foreign currencies, 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 March 31, 2017 to December 31, 2016, the Canadian dollar strengthened relative to the U.S. dollar resulting in unrealized gains of $3.9 million. See Note 11 to the Interim Financial Statements for further details.

### Capital Investment

| ($ millions) | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| Capital spending | $ 120.4 | $ 43.3 |
| Office capital | 0.1 | — |
| Sub-total | 120.5 | 43.3 |
| Property and land acquisitions | $ 2.5 | $ 3.6 |
| Property divestments | 0.9 | (187.8) |
| Sub-total | 3.4 | (184.2) |
| Total | $ 123.9 | $ (140.9) |

Capital spending for the three months ended March 31, 2017, totaled $120.4 million, compared to $43.3 million for the same period in 2016. The increase is in line with our strategy to re-initiate growth through an increased capital program in 2017. During the first quarter we spent $85.1 million on our North Dakota crude oil properties, $25.1 million on our Canadian crude oil properties and $9.8 million on our Marcellus natural gas assets.

During the first quarter, we completed a portion of our previously announced Canadian asset divestments. Although we recorded nominal proceeds on the divestment, which had associated natural gas production of 1,700 BOE/day, it resulted in a $25.1 million decrease in our asset retirement obligation. This divestment was offset by adjustments pertaining to prior period divestments. In comparison, during the same period of 2016 we disposed of several properties including certain Canadian Deep Basin properties located in Alberta for proceeds of $187.8 million with production of 5,400 BOE/day.

Subsequent to the first quarter, we closed the remaining 5,600 BOE/day of our previously announced divestments of various non-core Canadian properties. This included the remainder of our shallow gas assets and our Brooks waterflood property, for aggregate proceeds of $60.8 million, after closing adjustments.

We continue to expect 2017 annual capital spending of $450 million.

### Gain on Asset Sales and Note Repurchases

Under full cost accounting rules, divestments of oil and natural gas properties are generally accounted for as adjustments to the full cost pool with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would significantly alter the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss must be recognized. Gains and losses are evaluated on a case by case basis for each asset sale, and future sales may or may not result in such treatment. We did not record any gains or losses on divestments completed during the first quarter of 2017. In comparison, we recorded a gain of $145.1 million on asset divestments during the first quarter of 2016.

During the comparative period ended March 31, 2016, we recorded a gain of $7.1 million on the repurchase of US$172 million in outstanding senior notes at a discount to par value.

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

| ($ millions, except per BOE amounts) | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| DD&A expense | $ 60.6 | $ 91.3 |
| Per BOE | $ 7.92 | $ 10.26 |

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three months ended March 31, 2017, DD&A decreased when compared to the same period of 2016 primarily due to the cumulative effects of asset impairments recorded during 2016 as well as lower overall production.

### Impairment

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country basis using estimated after-tax future net cash flows discounted at 10 percent from proved reserves using SEC constant prices ("Standardized Measure"). SEC prices are calculated as the unweighted average of the trailing twelve first-day-of-the-month commodity prices. The Standardized Measure is not related to Enerplus' investment criteria and is not a fair value based measurement, but rather a prescribed accounting calculation. Under U.S. GAAP, impairments are not reversed in future periods.

The trailing twelve month average crude oil and natural gas prices increased in the first quarter of 2017 compared to a decrease during the same period in 2016. There were no non-cash impairments recorded in the three months ended March 31, 2017, compared to $46.2 million in the same period of 2016.

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the value of impairment losses from future ceiling tests. The primary factors include future first-day-of-the-month commodity prices, reserves revisions, our capital expenditure levels and timing, acquisition and divestment activity, as well as production levels, which affect DD&A expense. Although the trailing twelve month average commodity prices are approximately in line with current levels, there is the potential for prices to decline, impacting the ceiling value and resulting in non-cash impairments. See Note 5 to the Interim Financial Statements for trailing twelve month prices.

### Asset Retirement Obligation

In connection with our operations we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are based on our net ownership interest and management's estimate of costs to abandon and reclaim such assets and the timing of the cost to be incurred in future periods. We have estimated the net present value of our asset retirement obligation to be $155.5 million at March 31, 2017, compared to $181.7 million at December 31, 2016. Asset retirement obligation settlements were $2.5 million during the first quarters of 2017 and 2016. As a result of our divestments in the first quarter of 2017, we have reduced our asset retirement obligation by $25.1 million or 14%.

### Income Taxes

| ($ millions) | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| Current tax expense/(recovery) | $ 0.1 | $ (0.2) |
| Deferred tax expenses/(recovery) | 28.8 | 256.5 |
| Total tax expense/(recovery) | $ 28.9 | $ 256.3 |

We recorded a total tax expense of $28.9 million during the first quarter of 2017 compared to $256.3 million for the same period in 2016. The current quarter tax expense is primarily based on income reported in Canada and the U.S. compared to the first quarter of 2016 where we recorded an additional valuation allowance. We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not all or a portion of our deferred income tax assets will be realized. This assessment is primarily the result of projecting future taxable income using benchmark forward prices for 2017, held constant and adjusted for other significant items affecting taxable income. Our overall net deferred income tax asset was $700.2 million at March 31, 2017 (December 31, 2016 - $733.4 million).

## LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage, including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging and dividend levels. We also assess our leverage relative to our most restrictive debt covenant under our bank credit facility and senior notes, which is a maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At March 31, 2017, our senior debt to adjusted EBITDA ratio was 0.9x and our net debt to adjusted funds flow ratio was 0.9x. 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 and restricted cash at March 31, 2017 was $350.4 million, a decrease of 7% compared to $375.5 million at December 31, 2016. Total debt was comprised of $4.0 million of bank indebtedness and $740.0 million of senior notes less $393.6 million in cash, including restricted cash. Proceeds from the December, 2016 sale of our non-operated North Dakota properties are being held in escrow for a period of up to 180 days from the date of closing to facilitate possible future like-kind transactions in accordance with U.S. federal tax regulations. These proceeds have been classified as restricted cash on our balance sheet. At March 31, 2017, we were essentially 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% for the three months ended March 31, 2017, compared to 138% for the same period in 2016.

Our working capital deficiency, excluding cash, restricted cash and current deferred financial assets and liabilities, increased to $130.7 million at March 31, 2017 from $94.4 million at December 31, 2016. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, adjusted funds flow and our bank credit facility. We have sufficient liquidity to meet our financial commitments, as disclosed under "Commitments" in the Annual MD&A.

At March 31, 2017, 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 as material documents on our SEDAR profile at www.sedar.com.

The following table lists our financial covenants as at March 31, 2017:

| Covenant Description | | March 31, 2017 |
|---|---|---|
| **Bank Credit Facility:** | **Maximum Ratio** | |
| Senior debt to adjusted EBITDA(1) | 3.5x | 0.9x |
| Total debt to adjusted EBITDA | 4.0x | 0.9x |
| Total debt to capitalization | 50% | 22% |
| | | |
| **Senior Notes:** | **Maximum Ratio** | |
| Senior debt to adjusted EBITDA(2) | 3.0x - 3.5x | 0.9x |
| Senior debt to consolidated present value of total proved reserves(3) | 60% | 27% |
| | **Minimum Ratio** | |
| Adjusted EBITDA to interest | 4.0 x | 20.6x |

Definitions
"Senior debt" is calculated as the sum of drawn amounts on our bank credit facility, outstanding letters of credit and the principal amount of senior notes.
"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, impairment and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended March 31, 2017 were $130.1 million and $845.2 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 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

| ($ millions, except per share amounts) | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| Dividends to shareholders | $ 7.2 | $ 14.5 |
| Per weighted average share (Basic) | $ 0.03 | $ 0.07 |

During the three months ended March 31, 2017, we reported total dividends of $7.2 million or $0.03 per share, compared to $14.5 million or $0.07 per share for the same period in 2016. Effective with our April 2016 payment, we reduced our monthly dividend from $0.03 per share to $0.01 per share to provide additional financial flexibility and balance adjusted funds flow with capital and dividends.

The dividend is part of our strategy to create shareholder value; however, a sustained low price environment may impact our ability to pay dividends. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

### Shareholders' Capital

| | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| Share capital ($ millions) | $ 3,386.9 | $ 3,142.9 |
| Common shares outstanding (thousands) | 242,129 | 207,133 |
| Weighted average shares outstanding – basic (thousands) | 241,285 | 206,716 |
| Weighted average shares outstanding – diluted (thousands) | 246,358 | 206,716 |

During the first quarter of 2017, a total of 1,646,000 shares were issued pursuant to our LTI plans and accordingly, $21.0 million was transferred from paid-in capital to share capital (2016 – 594,000; $9.4 million). For further details, see Note 13 to the Interim Financial Statements.

On March 28, 2017, we filed a short form base shelf prospectus (the "Shelf Prospectus") with securities regulatory authorities in each of the provinces of Canada and a Registration Statement with the U.S. Securities Exchange Commission. The Shelf Prospectus allows us to offer and issue up to an aggregate amount of $2.0 billion of common shares, preferred shares, warrants, subscription receipts and units by way of one or more prospectus supplements during the 25-month period that the Shelf Prospectus remains in place.

At May 4, 2017, we had 242,128,944 shares outstanding.

## SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

| ($ millions, except per unit amounts) | Three months ended March 31, 2017 Canada | U.S. | Total | Three months ended March 31, 2016 Canada | U.S. | Total |
|---|---|---|---|---|---|---|
| **Average Daily Production Volumes[1]** | | | | | | |
| Crude oil (bbls/day) | 12,907 | 20,271 | 33,178 | 14,186 | 25,322 | 39,508 |
| Natural gas liquids (bbls/day) | 1,405 | 1,753 | 3,158 | 1,804 | 3,690 | 5,494 |
| Natural gas (Mcf/day) | 68,542 | 223,065 | 291,607 | 99,539 | 217,611 | 317,150 |
| Total average daily production (BOE/day) | 25,736 | 59,201 | 84,937 | 32,580 | 65,280 | 97,860 |
| **Pricing[2]** | | | | | | |
| Crude oil (per bbl) | $ 51.67 | $ 61.26 | $ 57.53 | $ 26.55 | $ 34.42 | $ 31.59 |
| Natural gas liquids (per bbl) | 37.09 | 38.30 | 37.76 | 24.98 | 4.68 | 11.34 |
| Natural gas (per Mcf) | 3.65 | 3.62 | 3.63 | 2.01 | 1.66 | 1.77 |
| **Capital Expenditures** | | | | | | |
| Capital spending | $ 25.0 | $ 95.4 | $ 120.4 | $ 19.1 | $ 24.2 | $ 43.3 |
| Acquisitions | 1.5 | 1.0 | 2.5 | 1.0 | 2.6 | 3.6 |
| Divestments | 0.9 | — | 0.9 | (188.3) | 0.5 | (187.8) |
| **Netback[3] Before Hedging** | | | | | | |
| Oil and natural gas sales | $ 87.2 | $ 190.5 | $ 277.7 | $ 56.7 | $ 113.8 | $ 170.5 |
| Royalties | (11.9) | (38.0) | (49.9) | (5.4) | (22.4) | (27.8) |
| Production taxes | (1.1) | (9.3) | (10.4) | (0.8) | (6.6) | (7.4) |
| Cash operating expenses | (26.6) | (23.7) | (50.3) | (43.5) | (28.8) | (72.3) |
| Transportation costs | (4.4) | (25.2) | (29.6) | (3.6) | (22.1) | (25.7) |
| Netback before hedging | $ 43.2 | $ 94.3 | $ 137.5 | $ 3.4 | $ 33.9 | $ 37.3 |
| **Other Expenses** | | | | | | |
| Commodity derivative instruments loss/(gain) | $ (57.6) | $ — | $ (57.6) | $ (13.5) | $ — | $ (13.5) |
| General and administrative expense[4] | 17.8 | 5.7 | 23.5 | 18.3 | 4.1 | 22.4 |
| Current income tax expense/(recovery) | — | 0.1 | 0.1 | (0.3) | 0.1 | (0.2) |

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

## 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 | Diluted |
|---|---|---|---|---|
| **2017** | | | | |
| First Quarter | $ 227.8 | $ 76.3 | $ 0.32 | $ 0.31 |
| **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 |
| **2015** | | | | |
| Fourth Quarter | $ 199.4 | $ (625.0) | $ (3.03) | $ (3.03) |
| Third Quarter | 228.3 | (292.7) | (1.42) | (1.42) |
| Second Quarter | 251.7 | (312.5) | (1.52) | (1.52) |
| First Quarter | 205.0 | (293.2) | (1.42) | (1.42) |
| Total 2015 | $ 884.4 | $ (1,523.4) | $ (7.39) | $ (7.39) |

Oil and natural gas sales, net of royalties, increased slightly in the first quarter of 2017 compared to the fourth quarter of 2016 due to higher realized crude oil and natural gas prices partially offset by lower oil and natural gas liquids production volumes. Oil and gas sales, net of royalties, decreased throughout 2015 and 2016 as commodity prices declined. During 2015, the impact of weak commodity prices was somewhat offset by increasing production. Net losses reported in 2015 and 2016 were primarily due to non-cash asset impairments and valuation allowances on our deferred tax asset related to the decrease in the trailing twelve month average commodity prices, along with reduced revenues. Net income in the fourth quarter of 2016 related primarily to the reversal of the valuation allowance on our deferred tax asset.

## 2017 UPDATED GUIDANCE

We are reducing our operating expense guidance to $6.85/BOE from $7.25/BOE and narrowing our expected 2017 average Marcellus differential to US$0.60/Mcf below NYMEX from US$0.90/Mcf. All other guidance is unchanged and is summarized below. This guidance includes our previously announced divestments of certain non-core Canadian properties, but does not include any additional acquisitions or divestments.

| Summary of 2017 Expectations | Target |
|---|---|
| Capital spending | $450 million |
| Average annual production | 81,000 – 85,000 BOE/day |
| Fourth quarter average production | 86,000 – 91,000 BOE/day |
| Average annual crude oil and natural gas liquids production | 38,500 – 41,500 bbls/day |
| Fourth quarter average annual crude oil and natural gas liquids production | 43,000 – 48,000 bbls/day |
| Average royalty and production tax rate (% of gross sales, before transportation) | 24% |
| Operating expenses | $6.85/BOE (from $7.25/BOE) |
| Transportation costs | $4.00/BOE |
| Cash G&A expenses | $1.85/BOE |

| 2017 Differential/Basis Outlook(1) | |
|---|---|
| Average U.S. Bakken crude oil differential (compared to WTI crude oil) | US$(4.50)/bbl |
| Average Marcellus natural gas sales price differential (compared to NYMEX natural gas) | US$(0.60)/Mcf (from US$(0.90)/Mcf) |

(1) Excluding transportation costs.

## NON-GAAP MEASURES

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

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

| Calculation of Netback | Three months ended March 31, | |
|---|---|---|
| ($ millions) | 2017 | 2016 |
| Oil and natural gas sales | $ 277.7 | $ 170.5 |
| Less: | | |
| Royalties | (49.9) | (27.8) |
| Production taxes | (10.4) | (7.4) |
| Cash operating expenses(1) | (50.3) | (72.3) |
| Transportation costs | (29.6) | (25.7) |
| Netback before hedging | $ 137.5 | $ 37.3 |
| Cash gains/(losses) on derivative instruments | 6.6 | 39.6 |
| Netback after hedging | $ 144.1 | $ 76.9 |

(1) Total operating expenses adjusted to exclude non-cash losses on fixed price electricity swaps of $0.1 million and $0.3 million in the three months ended March 31, 2017 and 2016, respectively.

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

| Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow | Three months ended March 31, | |
|---|---|---|
| ($ millions) | 2017 | 2016 |
| Cash flow from operating activities | $ 127.9 | $ 69.7 |
| Asset retirement obligation expenditures | 2.5 | 2.5 |
| Changes in non-cash operating working capital | (10.5) | (30.5) |
| Adjusted funds flow | $ 119.9 | $ 41.7 |

"**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 and restricted cash divided by a trailing twelve months of adjusted funds flow. This measure is not equivalent to debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") and is not a debt covenant.

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

| Calculation of Adjusted Payout Ratio | Three months ended March 31, | |
|---|---|---|
| ($ millions) | 2017 | 2016 |
| Dividends | $ 7.2 | $ 14.5 |
| Capital and office expenditures | 120.5 | 43.3 |
| Sub-total | $ 127.7 | $ 57.8 |
| Funds flow | $ 119.9 | $ 41.7 |
| Adjusted payout ratio (%) | 107% | 138% |

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

| Reconciliation of Net Income to Adjusted EBITDA(1) | |
|---|---|
| ($ millions) | March 31, 2017 |
| Net income | $ 647.4 |
| Add: | |
| Interest | 40.9 |
| Current and deferred tax expense/(recovery) | (464.7) |
| DD&A and asset impairment | 553.4 |
| Other non-cash charges(2) | 72.1 |
| Sub-total | $ 849.1 |
| Adjustment for material acquisitions and divestments(3) | (3.9) |
| Adjusted EBITDA | $ 845.2 |

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at March 31, 2017 include the three months ended March 31, 2017 and the second, third and fourth quarters of 2016.
(2) Includes the change in fair value of commodity derivatives, fixed price electricity swaps and equity swaps, non-cash SBC, and unrealized foreign exchange gains/losses.
(3) EBITDA is adjusted for material acquisitions or divestments during the period with net proceeds greater than $50 million as if that acquisition or disposition had been made at the beginning of the period.

In addition, the Company uses certain financial measures within the "Overview" and "Liquidity and Capital Resources" sections of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "total debt net of cash and restricted cash", "senior debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "maximum debt to consolidated present value of total proved reserves" and "adjusted EBITDA to interest" and are used to determine the Company's compliance with financial covenants under its bank credit facility and outstanding senior notes. Calculation of such terms is described under the "Liquidity and Capital Resources" section of this MD&A.

## INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a - 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109 - Certification of Disclosure in Issuer's Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at March 31, 2017, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on January 1, 2017 and ended March 31, 2017 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 2017 total, second half 2017, and fourth quarter 2017 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; 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 2017 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 2017 and impact thereof on our production levels and land holdings; potential future asset and goodwill impairments, as well as relevant factors that may affect such impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes 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; 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 2017 guidance contained in this MD&A is based on the following: a WTI price of US$55.00/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.75/GJ and a USD/CDN exchange rate of 1.35. 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 decline of 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 and Form 40-F as at December 31, 2016).*

## Condensed Consolidated Balance Sheets

| (CDN$ thousands) unaudited | Note | March 31, 2017 | December 31, 2016 |
|---|---|---|---|
| **Assets** | | | |
| Current Assets | | | |
| Cash | | $ 4,162 | $ 1,257 |
| Restricted Cash | | 389,436 | 392,048 |
| Accounts receivable | 3 | 93,232 | 115,368 |
| Deferred financial assets | 14 | 8,236 | — |
| Other current assets | | 10,803 | 6,721 |
| | | 505,869 | 515,394 |
| Property, plant and equipment: | | | |
| Oil and natural gas properties (full cost method) | 4 | 764,355 | 726,452 |
| Other capital assets, net | 4 | 11,005 | 11,978 |
| Property, plant and equipment | | 775,360 | 738,430 |
| Goodwill | | 650,095 | 651,663 |
| Deferred financial assets | 14 | 8,261 | — |
| Deferred income tax asset | 12 | 700,191 | 733,363 |
| **Total Assets** | | $ 2,639,776 | $ 2,638,850 |
| **Liabilities** | | | |
| Current liabilities | | | |
| Accounts payable | 6 | $ 203,007 | $ 184,534 |
| Dividends payable | | 2,421 | 2,405 |
| Current portion of long-term debt | 7 | 29,308 | 29,539 |
| Deferred financial liabilities | 14 | 6,356 | 28,615 |
| | | 241,092 | 245,093 |
| Deferred financial liabilities | 14 | 1,093 | 12,266 |
| Long-term debt | 7 | 714,691 | 739,286 |
| Asset retirement obligation | 8 | 155,526 | 181,700 |
| | | 871,310 | 933,252 |
| **Total Liabilities** | | 1,112,402 | 1,178,345 |
| **Shareholders' Equity** | | | |
| Share capital – authorized unlimited common shares, no par value | | | |
| Issued and outstanding: March 31, 2017 – 242 million shares | | | |
| December 31, 2016 – 240 million shares | 13 | 3,386,946 | 3,365,962 |
| Paid-in capital | | 60,919 | 73,783 |
| Accumulated deficit | | (2,263,590) | (2,332,641) |
| Accumulated other comprehensive income/(loss) | | 343,099 | 353,401 |
| | | 1,527,374 | 1,460,505 |
| **Total Liabilities & Shareholders' Equity** | | $ 2,639,776 | $ 2,638,850 |

| | |
|---|---|
| **Contingencies** | 15 |
| **Subsequent event** | 17 |

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

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

| (CDN$ thousands, except per share amounts) unaudited | Note | Three months ended March 31, 2017 | 2016 |
|---|---|---|---|
| **Revenues** | | | |
| Oil and natural gas sales, net of royalties | 9 | $ 227,816 | $ 142,661 |
| Commodity derivative instruments gain/(loss) | 14 | 57,562 | 13,464 |
| | | 285,378 | 156,125 |
| **Expenses** | | | |
| Operating | | 50,381 | 72,590 |
| Transportation | | 29,628 | 25,718 |
| Production taxes | | 10,364 | 7,436 |
| General and administrative | 10 | 23,493 | 22,453 |
| Depletion, depreciation and accretion | | 60,580 | 91,343 |
| Asset impairment | 5 | — | 46,177 |
| Interest | | 10,141 | 14,534 |
| Foreign exchange (gain)/loss | 11 | (3,858) | (54,408) |
| Gain on divestment of assets | 4 | — | (145,100) |
| Gain on prepayment of senior notes | 7 | — | (7,118) |
| Other expense/(income) | | (485) | (160) |
| | | 180,244 | 73,465 |
| **Income/(Loss) before taxes** | | 105,134 | 82,660 |
| Current income tax expense/(recovery) | 12 | 74 | (159) |
| Deferred income tax expense/(recovery) | 12 | 28,767 | 256,485 |
| **Net Income/(Loss)** | | $ 76,293 | $ (173,666) |
| | | | |
| **Other Comprehensive Income/(Loss)** | | | |
| Change in cumulative translation adjustment | | (10,302) | (66,368) |
| **Other Comprehensive Income/(Loss)** | | (10,302) | (66,368) |
| **Total Comprehensive Income/(Loss)** | | $ 65,991 | $ (240,034) |
| | | | |
| **Net income/(Loss) per share** | | | |
| Basic | 13 | $ 0.32 | $ (0.84) |
| Diluted | 13 | $ 0.31 | $ (0.84) |

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

## Condensed Consolidated Statements of Changes in Shareholders' Equity

| **Three months ended March 31** (CDN$ thousands) unaudited | | **2017** | | **2016** |
|---|---|---|---|---|
| **Share Capital** | | | | |
| Balance, beginning of year | $ | 3,365,962 | $ | 3,133,524 |
| Share-based compensation – settled | | 20,984 | | 9,407 |
| Balance, end of period | $ | 3,386,946 | $ | 3,142,931 |
| | | | | |
| **Paid-in Capital** | | | | |
| Balance, beginning of year | $ | 73,783 | $ | 56,176 |
| Share-based compensation – settled | | (20,984) | | (9,407) |
| Share-based compensation – non-cash | | 8,120 | | 3,429 |
| Balance, end of period | $ | 60,919 | $ | 50,198 |
| | | | | |
| **Accumulated Deficit** | | | | |
| Balance, beginning of year | $ | (2,332,641) | $ | (2,694,618) |
| Net income/(loss) | | 76,293 | | (173,666) |
| Dividends | | (7,242) | | (14,464) |
| Balance, end of period | $ | (2,263,590) | $ | (2,882,748) |
| | | | | |
| **Accumulated Other Comprehensive Income/(Loss)** | | | | |
| Balance, beginning of year | $ | 353,401 | $ | 402,672 |
| Change in cumulative translation adjustment | | (10,302) | | (66,368) |
| Balance, end of period | $ | 343,099 | $ | 336,304 |
| **Total Shareholders' Equity** | $ | 1,527,374 | $ | 646,685 |

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

## Condensed Consolidated Statements of Cash Flows

| (CDN$ thousands) unaudited | Note | Three months ended March 31, 2017 | 2016 |
|---|---|---|---|
| **Operating Activities** | | | |
| Net income/(loss) | | $ 76,293 | $ (173,666) |
| Non-cash items add/(deduct): | | | |
| Depletion, depreciation and accretion | | 60,580 | 91,343 |
| Asset impairment | | — | 46,177 |
| Changes in fair value of derivative instruments | 14 | (49,929) | 26,335 |
| Deferred income tax expense/(recovery) | 12 | 28,767 | 256,485 |
| Foreign exchange (gain)/loss on debt and working capital | 11 | (3,911) | (56,158) |
| Share-based compensation | 13 | 8,120 | 3,429 |
| Gain on divestment of assets | 4 | — | (145,100) |
| Gain on prepayment of senior notes | 7 | — | (7,118) |
| Asset retirement obligation expenditures | 8 | (2,541) | (2,454) |
| Changes in non-cash operating working capital | 16 | 10,544 | 30,474 |
| Cash flow from/(used in) operating activities | | 127,923 | 69,747 |
| **Financing Activities** | | | |
| Cash dividends | | (7,242) | (14,464) |
| Increase/(decrease) in bank credit facility | | (19,229) | 70,849 |
| Proceeds/(repayment) of senior notes | 7 | — | (226,029) |
| Changes in non-cash financing working capital | | 16 | (4,125) |
| Cash flow from/(used in) financing activities | | (26,455) | (173,769) |
| **Investing Activities** | | | |
| Capital and office expenditures | | (120,493) | (43,292) |
| Property and land acquisitions | | (2,536) | (3,554) |
| Property divestments | 4 | (899) | 187,768 |
| Decrease/(increase) in restricted cash | | 2,612 | — |
| Changes in non-cash investing working capital | | 26,322 | (42,125) |
| Cash flow from/(used in) investing activities | | (94,994) | 98,797 |
| Effect of exchange rate changes on cash | | (3,569) | (992) |
| Change in cash | | 2,905 | (6,217) |
| Cash, beginning of period | | 1,257 | 7,498 |
| **Cash, end of period** | | $ 4,162 | $ 1,281 |

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. The interim Consolidated Financial Statements were authorized for issue by the Board of Directors on May 5, 2017.

### 2) BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under accounting principles generally accepted in the United States of America ("U.S. GAAP") for the three months ended March 31, 2017 and the 2016 comparative periods. Certain information and notes normally included with the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2016. There are no differences in the use of estimates or judgments between these interim Consolidated Financial Statements and the audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2016.

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) ACCOUNTS RECEIVABLE

| ($ thousands) | March 31, 2017 | December 31, 2016 |
|---|---|---|
| Accrued receivables | $ 72,112 | $ 83,774 |
| Accounts receivable – trade | 22,824 | 33,305 |
| Current income tax receivable | 1,560 | 1,564 |
| Allowance for doubtful accounts | (3,264) | (3,275) |
| Total accounts receivable, net of allowance for doubtful accounts | $ 93,232 | $ 115,368 |

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

| As of March 31, 2017<br>($ thousands) | Cost | Accumulated Depletion, Depreciation, and Impairment | Net Book Value |
|---|---|---|---|
| Oil and natural gas properties | $ 13,620,458 | $ (12,856,103) | $ 764,355 |
| Other capital assets | 106,078 | (95,073) | 11,005 |
| Total PP&E | $ 13,726,536 | $ (12,951,176) | $ 775,360 |

| As of December 31, 2016<br>($ thousands) | Cost | Accumulated Depletion, Depreciation, and Impairment | Net Book Value |
|---|---|---|---|
| Oil and natural gas properties | $ 13,567,390 | $ (12,840,938) | $ 726,452 |
| Other capital assets | 106,070 | (94,092) | 11,978 |
| Total PP&E | $ 13,673,460 | $ (12,935,030) | $ 738,430 |

Under full cost accounting rules, divestitures of oil and gas properties are generally accounted for as adjustments to capitalized costs, with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would have otherwise significantly altered the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss must be recognized.

No gains were recognized on dispositions of oil and gas properties for the three months ended March 31, 2017. For the three months ended March 31, 2016, Enerplus disposed of certain Canadian properties for proceeds of $181.8 million, which resulted in a gain on disposition of $145.1 million.

### 5) ASSET IMPAIRMENT

| ($ thousands) | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| Oil and natural gas properties: | | |
| Canada cost centre | $ — | $ — |
| U.S. cost centre | — | 46,177 |
| Impairment expense | $ — | $ 46,177 |

With increases in the 12-month average trailing crude oil and natural gas prices, there was no impairment recorded in 2017. The impairment for the three months ended March 31, 2016 was due to lower 12-month average trailing crude oil and natural gas prices.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from March 31, 2016 through March 31, 2017:

| Period | WTI Crude Oil US$/bbl | Exchange Rate US$/CDN$ | Edm Light Crude CDN$/bbl | U.S. Henry Hub Gas US$/Mcf | AECO Natural Gas Spot CDN$/Mcf |
|---|---|---|---|---|---|
| Q1 2017 | $ 47.61 | 1.31 | $ 58.02 | $ 2.77 | $ 2.41 |
| Q4 2016 | 42.75 | 1.32 | 52.26 | 2.49 | 2.17 |
| Q3 2016 | 41.68 | 1.32 | 51.17 | 2.27 | 2.06 |
| Q2 2016 | 43.12 | 1.32 | 53.16 | 2.25 | 2.14 |
| Q1 2016 | 46.26 | 1.31 | 56.97 | 2.41 | 2.47 |

### 6) ACCOUNTS PAYABLE

| ($ thousands) | March 31, 2017 | December 31, 2016 |
|---|---|---|
| Accrued payables | $ 118,379 | $ 104,816 |
| Accounts payable - trade | 84,628 | 79,718 |
| Total accounts payable | $ 203,007 | $ 184,534 |

### 7) DEBT

| ($ thousands) | March 31, 2017 | December 31, 2016 |
|---|---|---|
| Current: | | |
| Senior notes | $ 29,308 | $ 29,539 |
| | 29,308 | 29,539 |
| Long-term: | | |
| Bank credit facility | $ 3,997 | $ 23,226 |
| Senior notes | 710,694 | 716,060 |
| | 714,691 | 739,286 |
| Total debt | $ 743,999 | $ 768,825 |

The terms and rates of the Company's outstanding senior notes are provided below:

| Issue Date | Interest Payment Dates | Principal Repayment | Coupon Rate | Original Principal ($ thousands) | Remaining Principal ($ thousands) | CDN$ Carrying Value ($ thousands) |
|---|---|---|---|---|---|---|
| September 3, 2014 | March 3 and Sept 3 | 5 equal annual installments beginning September 3, 2022 | 3.79% | US$200,000 | US$105,000 | $ 139,820 |
| 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 | 26,644 |
| May 15, 2012 | May 15 and Nov 15 | 5 equal annual installments beginning May 15, 2020 | 4.40% | US$355,000 | US$298,000 | 396,996 |
| June 18, 2009 | June 18 and Dec 18 | 5 equal annual installments beginning June 18, 2017 | 7.97% | US$225,000 | US$110,000 | 146,542 |
| | | | | | **Total carrying value** | $ 740,002 |
| | | | | | **Current portion** | 29,308 |
| | | | | | **Long-term portion** | $ 710,694 |

For the period ended March 31, 2017, there were no senior note repurchases. For the period ended March 31, 2016 Enerplus repurchased US$172 million in outstanding senior notes at a discount, resulting in a gain of $7.1 million, for a total payment of $226.0 million.

## 8) ASSET RETIREMENT OBLIGATION

Enerplus has estimated the present value of its asset retirement obligation to be $155.5 million at March 31, 2017 compared to $181.7 million at December 31, 2016 based on a total undiscounted liability of $414.2 million and $452.1 million, respectively. The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.84% (December 31, 2016 – 5.86%).

| ($ thousands) | Three months ended March 31, 2017 | Year ended December 31, 2016 |
|---|---|---|
| Balance, beginning of year | $ 181,700 | $ 206,359 |
| Change in estimates | (1,164) | 5,496 |
| Property acquisitions and development activity | 314 | 3,003 |
| Dispositions | (25,050) | (35,635) |
| Settlements | (2,541) | (8,390) |
| Accretion expense | 2,267 | 10,867 |
| Balance, end of period | $ 155,526 | $ 181,700 |

## 9) OIL AND NATURAL GAS SALES

| | Three months ended March 31, | |
|---|---|---|
| ($ thousands) | **2017** | **2016** |
| Oil and natural gas sales | $ 277,745 | $ 170,423 |
| Royalties(1) | (49,929) | (27,762) |
| Oil and natural gas sales, net of royalties | $ 227,816 | $ 142,661 |

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

## 10) GENERAL AND ADMINISTRATIVE EXPENSE

| | Three months ended March 31, | |
|---|---|---|
| ($ thousands) | **2017** | **2016** |
| General and administrative expense | $ 14,271 | $ 18,426 |
| Share-based compensation expense | 9,222 | 4,027 |
| General and administrative expense | $ 23,493 | $ 22,453 |

## 11) FOREIGN EXCHANGE

| ($ thousands) | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| Realized: | | |
| Foreign exchange (gain)/loss | $ 53 | $ 1,750 |
| Unrealized: | | |
| Translation of U.S. dollar debt and working capital (gain)/loss | (3,911) | (56,158) |
| Foreign exchange (gain)/loss | $ (3,858) | $ (54,408) |

## 12) INCOME TAXES

Enerplus' provision for income tax is as follows:

| ($ thousands) | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| Current tax expense/(recovery) | | |
| Canada | $ — | $ (303) |
| United States | 74 | 144 |
| Current tax expense/(recovery) | 74 | (159) |
| Deferred tax expense/(recovery) | | |
| Canada | $ 13,619 | $ 12,846 |
| United States | 15,148 | 243,639 |
| Deferred tax expense/(recovery) | 28,767 | 256,485 |
| Income tax expense/(recovery) | $ 28,841 | $ 256,326 |

The difference between expected income taxes based on the statutory income tax rate and the effective income tax rate 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. As at March 31, 2017 Enerplus' total valuation allowance was $347.1 million (December 31, 2016 - $347.9 million).

## 13) SHAREHOLDERS' EQUITY

### a) Share Capital

| | Three months ended March 31, 2017 | | Year ended December 31, 2016 | |
|---|---|---|---|---|
| **Authorized unlimited number of common shares issued:** (thousands) | **Shares** | **Amount** | **Shares** | **Amount** |
| Balance, beginning of year | 240,483 | $ 3,365,962 | 206,539 | $ 3,133,524 |
| Issued for cash: | | | | |
| Issue of shares | — | — | 33,350 | 230,115 |
| Share issue costs (net of tax of $2,621) | — | — | — | (7,084) |
| Non-cash: | | | | |
| Share-based compensation – settled | 1,646 | 20,984 | 594 | 9,407 |
| Balance, end of period | 242,129 | $ 3,386,946 | 240,483 | $ 3,365,962 |

Dividends declared to shareholders for the three months ended March 31, 2017 was $7.2 million (2016 - $14.5 million).

On May 31, 2016, Enerplus issued 33,350,000 common shares at a price of $6.90 per share for gross proceeds of $230,115,000 ($220,410,400, net of issue costs before tax).

### b) Share-based Compensation

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

| ($ thousands) | Three months ended March 31, 2017 | 2016 |
|---|---|---|
| Cash: | | |
| Long-term incentive plans expense | $ 155 | $ 733 |
| Non-cash: | | |
| Long-term incentive plans and stock option expense | 8,120 | 3,429 |
| Equity swap (gain)/loss | 947 | (135) |
| Share-based compensation expense | $ 9,222 | $ 4,027 |

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

In 2014, the Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") plans were amended such that grants under the plans are settled through the issuance of treasury shares. The amendment was effective beginning with our grant in March of 2014 and any prior grants were settled in cash. The final cash-settled PSU and RSU grants were settled in December, 2015 and March, 2016, respectively. The Company's Director Share Units ("DSU") continue to be granted as cash-settled awards.

The following table summarizes the PSU, RSU and DSU activity for the three months ended March 31, 2017:

| For the three months ended March 31, 2017 | Cash-settled LTI plans | Equity-settled LTI plans | | Total |
|---|---|---|---|---|
| (thousands of units) | DSU | PSU | RSU | |
| Balance, beginning of year | 306 | 2,442 | 2,698 | 5,446 |
| Granted | 59 | 814 | 805 | 1,678 |
| Vested | — | (528) | (1,118) | (1,646) |
| Forfeited | — | — | (41) | (41) |
| Balance, end of period | 365 | 2,728 | 2,344 | 5,437 |

#### Cash-settled LTI Plans

For the three months ended March 31, 2017, the Company recorded cash share-based compensation of $0.2 million (March 31, 2016 - expense of $0.7 million). For the three months ended March 31, 2017 the Company made cash payments of $0.1 million related to its cash-settled plans (March 31, 2016 - $2.7 million).

As of March 31, 2017, a liability of $3.9 million (December 31, 2016 - $3.9 million) with respect to the DSU plan has been recorded to Accounts Payable on the Consolidated Balance Sheets.

#### Equity-settled LTI Plans

For the three months ended March 31, 2017 the Company recorded non-cash share-based compensation expense of $8.1 million (2016 – $3.4 million).

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

| At March 31, 2017 ($ thousands, except for years) | PSU(1) | RSU | Total |
|---|---|---|---|
| Cumulative recognized share-based compensation expense | $ 18,657 | $ 7,295 | $ 25,952 |
| Unrecognized share-based compensation expense | 16,900 | 11,374 | 28,274 |
| Fair value | $ 35,557 | $ 18,669 | $ 54,226 |
| Weighted-average remaining contractual term (years) | 1.9 | 1.7 | |

(1) Includes estimated performance multipliers.

### ii) Stock Option Plan

The Company suspended the issuance of stock options in 2014. At March 31, 2017 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 period ended March 31, 2017:

| Period ended March 31, 2017 | Number of Options (thousands) | Weighted Average Exercise Price |
|---|---|---|
| Options outstanding, beginning of year | 5,900 | $ 18.29 |
| Forfeited | (29) | 18.68 |
| Options outstanding, end of period | 5,871 | $ 18.29 |
| Options exercisable, end of period | 5,871 | $ 18.29 |

At March 31, 2017, Enerplus had 5,870,740 options that were exercisable at a weighted average reduced exercise price of $18.29 with a weighted average remaining contractual term of 2.3 years, giving an aggregate intrinsic value of nil (2016 – 3.3 years and nil). The intrinsic value of options exercised for the three months ended March 31, 2017 was nil (March 31, 2016 – nil).

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

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

| | Three months ended March 31, | |
|---|---|---|
| (thousands, except per share amounts) | 2017 | 2016 |
| Net income/(loss) | $ 76,293 | $ (173,666) |
| Weighted average shares outstanding – Basic | 241,285 | 206,716 |
| Dilutive impact of share-based compensation(1) | 5,073 | — |
| Weighted average shares outstanding – Diluted | 246,358 | 206,716 |
| Net income/(loss) per share | | |
| Basic | $ 0.32 | $ (0.84) |
| Diluted(1) | $ 0.31 | $ (0.84) |

(1) For the three months ended March 31, 2016 the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the loss per share.

## 14) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

### a) Fair Value Measurements

At March 31, 2017 the carrying value of cash, restricted cash, accounts receivable, accounts payable, dividends payable and bank credit facilities approximated their fair value due to the short-term maturity of the instruments.

At March 31, 2017 senior notes had a carrying value of $740.0 million and a fair value of $766.6 million (December 31, 2016 - $746.0 million and $771.0 million, respectively).

There were no transfers between fair value hierarchy levels during the period.

### b) Derivative Financial Instruments

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

The following table summarizes the change in fair value for the three months ended March 31, 2017 and 2016:

| **Gain/(Loss)** ($ thousands) | Three months ended March 31, 2017 | Three months ended March 31, 2016 | Income Statement Presentation |
|---|---|---|---|
| Electricity Swaps | $ (117) | $ (308) | Operating expense |
| Equity Swaps | (947) | 135 | General and administrative expense |
| Commodity Derivative Instruments: | | | |
| Oil | 44,358 | (31,276) | Commodity derivative instruments |
| Gas | 6,635 | 5,114 | |
| Total | $ 49,929 | $ (26,335) | |

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

| ($ thousands) | Three months ended March 31, 2017 | Three months ended March 31, 2016 |
|---|---|---|
| Change in fair value gain/(loss) | $ 50,993 | $ (26,162) |
| Net realized cash gain/(loss) | 6,569 | 39,626 |
| Commodity derivative instruments gain/(loss) | $ 57,562 | $ 13,464 |

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

| | March 31, 2017 | | | | December 31, 2016 | |
|---|---|---|---|---|---|---|
| | Assets | | Liabilities | | Liabilities | |
| ($ thousands) | Current | Long-term | Current | Long-term | Current | Long-term |
| Electricity Swaps | $ — | $ — | $ 758 | $ — | $ 641 | $ — |
| Equity Swaps | — | — | 1,789 | 1,093 | 1,044 | 891 |
| Commodity Derivative Instruments: | | | | | | |
| Oil | 8,236 | 8,261 | 980 | — | 17,466 | 11,375 |
| Gas | — | — | 2,829 | — | 9,464 | — |
| Total | $ 8,236 | $ 8,261 | $ 6,356 | $ 1,093 | $ 28,615 | $ 12,266 |

### c) Risk Management

### i) Market Risk

Market risk is comprised of commodity price, foreign exchange, interest rate and equity price risk.

**Commodity Price Risk:**

Enerplus manages a portion of commodity price risk through a combination of financial derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts subject to a maximum of 80% of forecasted production volumes net of royalties and production taxes.

The following tables summarize the Corporation's price risk management positions at May 4, 2017:

*Crude Oil Instruments:*

| Instrument Type[1] | bbls/day | US$/bbl |
|---|---|---|
| Apr 1, 2017 – May 31, 2017 | | |
| WTI Swap | 2,000 | 53.50 |
| WTI Purchased Put | 14,000 | 50.29 |
| WTI Sold Call | 14,000 | 61.14 |
| WTI Sold Put | 14,000 | 38.94 |
| WCS Differential Swap | 2,000 | (14.75) |
| Jun 1, 2017 – Jun 30, 2017 | | |
| WTI Swap | 2,000 | 53.50 |
| WTI Purchased Put | 14,000 | 50.29 |
| WTI Sold Call | 14,000 | 61.14 |
| WTI Sold Put | 14,000 | 38.94 |
| WCS Differential Swap | 3,000 | (14.45) |
| Jul 1, 2017 – Dec 31, 2017 | | |
| WTI Swap | 2,000 | 53.50 |
| WTI Purchased Put | 18,000 | 50.61 |
| WTI Sold Call | 18,000 | 60.33 |
| WTI Sold Put | 18,000 | 39.62 |
| WCS Differential Swap | 3,000 | (14.45) |
| Jan 1, 2018 – Dec 31, 2018 | | |
| WTI Swap | 3,000 | 53.73 |
| WTI Purchased Put | 9,500 | 54.00 |
| WTI Sold Call | 9,500 | 63.09 |
| WTI Sold Put | 9,500 | 43.13 |
| Jan 1, 2019 – Mar 31, 2019 | | |
| WTI Swap | 3,000 | 53.73 |
| WTI Purchased Put | 1,000 | 56.00 |
| WTI Sold Call | 1,000 | 70.00 |
| WTI Sold Put | 1,000 | 45.00 |
| Apr 1, 2019 – Dec 31, 2019 | | |
| WTI Purchased Put | 4,000 | 54.69 |
| WTI Sold Call | 4,000 | 66.18 |
| WTI Sold Put | 4,000 | 43.75 |

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

*Natural Gas Instruments:*

| Instrument Type[1] | MMcf/day | US$/Mcf |
|---|---|---|
| Apr 1, 2017 – Dec 31, 2017 | | |
| NYMEX Purchased Put | 50.0 | 2.75 |
| NYMEX Sold Call | 50.0 | 3.41 |
| NYMEX Sold Put | 50.0 | 2.06 |

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

*Electricity Instruments:*

| Instrument Type | MWh | CDN$/Mwh |
|---|---|---|
| Apr 1, 2017 – Dec 31, 2017 | | |
| AESO Power Swap[1] | 6.0 | 44.38 |

(1) Alberta Electrical System Operator ("AESO") fixed pricing.

*Physical Contracts:*

| Instrument Type | MMcf/day | US$/Mcf |
|---|---|---|
| *Purchases:* | | |
| Apr 1, 2017 – Jun 30, 2017<br>AECO-NYMEX Basis | 35.0 | (1.16) |
| Jul 1, 2017 – Oct 31, 2017<br>AECO-NYMEX Basis | 10.0 | (1.17) |
| *Sales:* | | |
| Apr 1, 2017 – Jun 30, 2017<br>AECO-NYMEX Basis | 35.0 | (0.66) |
| Jul 1, 2017 – Oct 31, 2017<br>AECO-NYMEX Basis | 35.0 | (0.66) |
| Nov 1, 2017 – Oct 31, 2018<br>AECO-NYMEX Basis | 35.0 | (0.66) |
| Nov 1, 2018 – Oct 31, 2019<br>AECO-NYMEX Basis | 35.0 | (0.64) |

**Foreign Exchange Risk:**

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations, and U.S. dollar denominated senior notes and working capital. Additionally, Enerplus' crude oil sales and a portion of its natural gas sales are based on U.S. dollar indices. To mitigate exposure to fluctuations in foreign exchange, Enerplus may enter into foreign exchange derivatives. At March 31, 2017 Enerplus did not have any foreign exchange derivatives outstanding.

**Interest Rate Risk:**

As of March 31, 2017 almost 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 13. Enerplus has entered into various equity swaps maturing between 2017 and 2018 and has effectively fixed the future settlement cost on 470,000 shares at weighted average price of $16.89 per share.

**ii) Credit Risk**

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

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

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At March 31, 2017 approximately 62% of Enerplus' marketing receivables were with companies considered investment grade.

At March 31, 2017 approximately $3.4 million or 4% of Enerplus' total accounts receivable were aged over 120 days and considered past due. The majority of these accounts are due from various joint venture partners. Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts of future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectable the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at March 31, 2017 was $3.3 million (December 31, 2016 - $3.3 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, as well as acquisition and divestment activity.

At March 31, 2017 Enerplus was in full compliance with all covenants under the bank credit facility and outstanding senior notes.

## 15) 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.

## 16) SUPPLEMENTAL CASH FLOW INFORMATION

### a) Changes in Non-Cash Operating Working Capital

| | Three months ended March 31, | |
|---|---|---|
| ($ thousands) | 2017 | 2016 |
| Accounts receivable | $ 21,672 | $ 61,077 |
| Other current assets | (4,311) | 3,331 |
| Accounts payable | (6,817) | (33,934) |
| | $ 10,544 | $ 30,474 |

### b) Other

| | Three months ended March 31, | |
|---|---|---|
| ($ thousands) | 2017 | 2016 |
| Income taxes paid/(received) | $ 65 | $ (1,924) |
| Interest paid | $ 3,644 | $ 9,806 |

## 17) SUBSEQUENT EVENT

Subsequent to March 31, 2017, Enerplus closed the divestment of certain non-core Canadian assets for proceeds of approximately $60.8 million, after closing adjustments.

## BOARD OF DIRECTORS

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

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

**Michael R. Culbert**(3)(5)(9)
Corporate Director
Calgary, Alberta

**Ian C. Dundas**
President & Chief Executive Officer
Enerplus Corporation
Calgary, Alberta

**Hilary A. Foulkes**(7)(9)(11)
Corporate Director
Calgary, Alberta

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

**Susan M. MacKenzie**(7)(10)(11)
Corporate Director
Calgary, Alberta

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

**Sheldon B. Steeves**(5)(8)
Corporate Director
Calgary, Alberta

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

## OFFICERS

### ENERPLUS CORPORATION

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

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

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

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

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

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

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

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

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

**Shaina B. Morihira**
Corporate Controller

# CORPORATE INFORMATION

**OPERATING COMPANIES OWNED BY ENERPLUS CORPORATION**

Enerplus Resources (USA) Corporation

**LEGAL COUNSEL**

Blake, Cassels & Graydon LLP
Calgary, Alberta

**AUDITORS**

Deloitte 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 |
| **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 |
| **SDP** | stock dividend program |
| **U.S. GAAP** | accounting principles generally accepted in the United States of America |
| **WCS** | Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing purposes |
| **WTI** | West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing |

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ERF LISTED ON TMX Toronto Stock Exchange

ERF LISTED NYSE