enerPLUS

# 2015

FINANCIAL SUMMARY

# 2015 FINANCIAL SUMMARY

## Selected Financial Results

| SELECTED FINANCIAL RESULTS | Three months ended December 31, 2015 | Three months ended December 31, 2014 | Twelve months ended December 31, 2015 | Twelve months ended December 31, 2014 |
|---|---|---|---|---|
| **Financial (000's)** | | | | |
| Funds Flow[4] | $ 102,674 | $ 212,518 | $ 493,101 | $ 859,020 |
| Cash and Stock Dividends | 22,717 | 55,511 | 131,955 | 221,098 |
| Net Income/(Loss) | (624,987) | 151,652 | (1,523,403) | 299,076 |
| Debt Outstanding – net of cash | 1,216,184 | 1,134,894 | 1,216,184 | 1,134,894 |
| Capital Spending | 89,490 | 180,999 | 493,403 | 811,026 |
| Property and Land Acquisitions | 8,794 | 1,305 | 9,552 | 18,491 |
| Property Divestments | 83,236 | 17,945 | 286,614 | 203,576 |
| Debt to Funds Flow Ratio[4] | 2.5x | 1.3x | 2.5x | 1.3x |
| **Financial per Weighted Average Shares Outstanding** | | | | |
| Funds Flow | $ 0.50 | $ 1.03 | $ 2.39 | $ 4.20 |
| Net Income/(Loss) | (3.03) | 0.74 | (7.39) | 1.46 |
| Weighted Average Number of Shares Outstanding (000's) | 206,517 | 205,519 | 206,205 | 204,510 |
| **Selected Financial Results per BOE**[1][2] | | | | |
| Oil & Natural Gas Sales[3] | $ 23.81 | $ 40.50 | $ 27.07 | $ 49.13 |
| Royalties and Production Taxes | (4.75) | (9.13) | (5.63) | (10.75) |
| Commodity Derivative Instruments | 7.50 | 4.71 | 7.40 | 0.09 |
| Cash Operating Expenses | (8.68) | (9.51) | (8.75) | (9.23) |
| Transportation Costs | (2.98) | (2.91) | (2.95) | (2.69) |
| General and Administrative | (1.75) | (2.62) | (2.09) | (2.22) |
| Cash Share-Based Compensation | 0.16 | 1.40 | (0.02) | 0.03 |
| Interest, Foreign Exchange and Other Expenses | (2.94) | (1.23) | (2.78) | (1.42) |
| Current Tax (Expense)/Recovery | 0.07 | 0.67 | 0.43 | (0.12) |
| Funds Flow | $ 10.44 | $ 21.88 | $ 12.68 | $ 22.82 |

| SELECTED OPERATING RESULTS | Three months ended December 31, 2015 | Three months ended December 31, 2014 | Twelve months ended December 31, 2015 | Twelve months ended December 31, 2014 |
|---|---|---|---|---|
| **Average Daily Production**[2] | | | | |
| Crude Oil (bbls/day) | 41,135 | 42,818 | 41,639 | 40,208 |
| Natural Gas Liquids (bbls/day) | 5,092 | 3,487 | 4,763 | 3,565 |
| Natural Gas (Mcf/day) | 364,065 | 355,709 | 360,733 | 356,142 |
| Total (BOE/day) | 106,905 | 105,591 | 106,524 | 103,130 |
| % Crude Oil and Natural Gas Liquids | 43% | 44% | 44% | 42% |
| **Average Selling Price**[2][3] | | | | |
| Crude Oil (per bbl) | $ 43.04 | $ 69.17 | $ 48.43 | $ 86.28 |
| Natural Gas Liquids (per bbl) | 16.61 | 42.34 | 18.06 | 51.72 |
| Natural Gas (per Mcf) | 1.89 | 3.25 | 2.15 | 3.94 |
| Net Wells Drilled | 2 | 25 | 46 | 88 |

(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 December 31, 2015 | Three months ended December 31, 2014 | Twelve months ended December 31, 2015 | Twelve months ended December 31, 2014 |
|---|---|---|---|---|
| WTI crude oil (US$/bbl) | $ 42.18 | $ 73.15 | $ 48.80 | $ 93.00 |
| AECO natural gas – monthly index (CDN$/Mcf) | 2.65 | 4.01 | 2.77 | 4.42 |
| AECO natural gas – daily index (CDN$/Mcf) | 2.47 | 3.60 | 2.69 | 4.51 |
| NYMEX natural gas – last day (US$/Mcf) | 2.27 | 4.00 | 2.66 | 4.41 |
| US/CDN exchange rate | 1.34 | 1.14 | 1.28 | 1.10 |

| Share Trading Summary<br>For the twelve months ended December 31, 2015 | CDN* – ERF (CDN$) | U.S.** – ERF (US$) |
|---|---|---|
| High | $ 16.09 | $ 13.16 |
| Low | $ 4.24 | $ 3.01 |
| Close | $ 4.75 | $ 3.42 |

* TSX and other Canadian trading data combined.

** NYSE and other U.S. trading data combined.

| 2015 Dividends per Share | CDN$ | US$[(1)] |
|---|---|---|
| First Quarter Total | $ 0.27 | $ 0.22 |
| Second Quarter Total | $ 0.15 | $ 0.12 |
| Third Quarter Total | $ 0.15 | $ 0.12 |
| Fourth Quarter Total | $ 0.13 | $ 0.10 |
| Total Year-to-Date | $ 0.70 | $ 0.56 |

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

# 2015 HIGHLIGHTS

**Financial and Operational Highlights**

- Enerplus delivered fourth quarter production of 106,905 BOE per day, contributing to annual average production of 106,524 BOE per day, approximately 3% higher than 2014 and above guidance of 106,000 BOE per day. This strong production was despite a 39% reduction in capital spending year-over-year and over 6,000 BOE per day of production divested during the year which, given the timing of the divestments, reduced annual average volumes by approximately 1,300 BOE per day.

- Crude oil and natural gas liquids production also exceeded guidance, averaging 46,227 barrels per day in the fourth quarter and 46,402 barrels per day in 2015. This represents liquids production growth of approximately 6% over 2014. The higher liquids production is attributed to strong production growth in North Dakota which averaged approximately 27,700 BOE per day during 2015, up 28% from 2014.

- Enerplus exceeded its production targets, despite lower than budgeted capital spending of $89 million in the fourth quarter, as a result of continued well outperformance and further cost savings. Full year capital spending was $493 million, below guidance of $510 million. Enerplus' 2015 capital program was focused primarily on its oil portfolio in North Dakota and its Canadian waterfloods where it directed approximately 85% of capital. Enerplus drilled 1.8 net wells and brought 6.2 net wells on-stream in the fourth quarter, and drilled 46 net wells and brought 57 net wells on-stream during the full year 2015.

- Fourth quarter funds flow was $103 million ($0.50 per share), down approximately 15% from the previous quarter primarily as a result of lower commodity prices and production volumes. Full year funds flow was $493 million ($2.39 per share), down approximately 43% primarily due to significantly lower crude oil and natural gas prices relative to 2014. Commodity hedging helped support funds flow during 2015 with cash gains of $288 million.

- Continued improvement in Enerplus' cost structure resulted in both 2015 operating costs and G&A costs lower than guidance. Fourth quarter and full-year 2015 operating costs of $8.71 per BOE and $8.76 per BOE, were 10% and 5% lower than comparable periods in 2014, respectively. Fourth quarter and full-year 2015 G&A costs of $1.75 per BOE and $2.09 per BOE, were 33% and 6% lower than comparable periods in 2014, respectively. Reduced capital activity and divestments throughout the year resulted in Enerplus rationalizing its operations and reducing its workforce by approximately 20% which, along with ongoing cost savings initiatives, contributed to the lower G&A costs.

- Enerplus reported a net loss of $625 million in the fourth quarter as it incurred non-cash charges including $266 million related to an asset impairment and a $426 million valuation allowance for deferred tax assets. Under U.S. GAAP, Enerplus is required to use twelve month trailing average prices to determine impairment, and consequently the impairment reflects the low commodity prices throughout 2015. Enerplus reported a net loss for the full year of $1,523 million and impairment charges of $1,352 million. Under U.S. GAAP impairments are not reversed in future periods.

- Enerplus continues to maintain its financial flexibility through its ongoing reduction to cost structures, successful non-core asset sales and disciplined capital spending. Enerplus ended the year with total debt net of cash of $1,216 million, including 11% drawn on its $800 million bank credit facility. Year-end debt to funds flow ratio was 2.5 times and debt to EBITDA ratio was 2.2 times.

- In addition to divestments announced during 2015, Enerplus sold various non-core Canadian shallow gas assets located in southern Alberta in the fourth quarter. These were lower margin properties with dry gas production and higher operating costs than Enerplus' corporate average, comprising approximately 2,300 gross shallow gas wells (1,700 net wells). This divestment reduced the Company's Canadian well count by approximately 17%, and reduced its overall abandonment obligations by approximately 15%. The cash consideration for these assets was nominal. Production from these properties was approximately 2,700 BOE per day (99% natural gas). This divestment further improves the focus and concentration of Enerplus' portfolio and is expected to improve the Company's netback as a result of the higher relative operating costs of these assets and have a modest impact on funds flow.

- Subsequent to year-end, Enerplus announced two Deep Basin asset divestments for total proceeds of $193 million. The Company received proceeds of $183 million, before adjustments, on the closing of one sale in January 2016, and expects the second transaction to close during the first quarter of 2016. Proceeds have been used to repay Enerplus' drawn bank credit facility as well as a portion of its outstanding senior notes which has further improved the Company's liquidity position.

**Reserves Highlights**

Enerplus delivered another year of strong reserves results in 2015:

- Replaced 108% of 2015 production, adding 42 MMBOE of proved plus probable ("2P") reserves. Well performance in both North Dakota and the Marcellus continued to exceed the previous forecasts of Enerplus' independent reserves engineers and resulted in significant positive technical revisions.
- Replaced 163% of 2015 crude oil and NGL production, adding 27 MMBOE of 2P crude oil and NGL reserves primarily from North Dakota. Crude oil and NGLs now comprise 51% of 2P reserves.
- 2P finding and development costs ("F&D") decreased by 14% year-over-year to $8.44 per BOE, including future development costs ("FDC"). Enerplus' three-year average 2P F&D is $10.10 per BOE. Proved producing F&D was $11.90 per BOE in 2015.
- Enerplus sold various properties representing 27 MMBOE of 2P reserves at a value of $13.36 per BOE. Total 2P reserves, net of divestments, were 406 MMBOE at year-end 2015, representing a 5% decrease from 2014.
- 2P finding, development and acquisition costs ("FD&A") were $0.25 per BOE including FDC. Enerplus' three-year average 2P FD&A is $7.76 per BOE.
- 2P reserves in North Dakota increased 17%, including positive technical revisions, to 144 MMBOE, at an F&D of $7.60 per BOE. Based on an average operating netback of $18.66 per BOE in 2015, this represents a recycle ratio of 2.5.
- Proved ("1P") reserves continue to comprise a significant proportion of 2P reserves at 68%. Proved producing reserves represent 49% of 2P reserves.
- Strong reserves life index of 12.2 years, up from 10.7 years at year-end 2014, in part due to a lower production forecast given reduced levels of capital spending in the current low commodity price environment.
- Using the December 31, 2015 independent reserves evaluation, the net present value of Enerplus' 2P reserves discounted at 10%, net of debt and asset retirement obligations and including undeveloped acreage value, is estimated to be $11.65 per share.

# Management's Discussion and Analysis ("MD&A")

The following discussion and analysis of financial results is dated February 18, 2016 and is to be read in conjunction with the audited Consolidated Financial Statements (the "Financial Statements") of Enerplus Corporation ("Enerplus" or the "Company"), as at December 31, 2015 and 2014 and for the years ended December 31, 2015, 2014 and 2013.

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" below for further information.

## BASIS OF PRESENTATION

The 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 with the 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. The BOE and Mcfe rates 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 natural gas sales are presented net of royalties in the Financial Statements. Under International Financial Reporting Standards, industry standard is to present oil and natural gas sales before deduction of royalties and as such this MD&A presents production, oil and natural gas sales, and BOE measures before deduction of royalties to remain comparable with our peers.

The following table provides a reconciliation of our production volumes:

| | Years ended December 31, | | |
|---|---|---|---|
| **Average Daily Production Volumes** | **2015** | **2014** | **2013** |
| **Company interest production volumes** | | | |
| Crude oil (bbls/day) | 41,639 | 40,208 | 38,250 |
| Natural gas liquids (bbls/day) | 4,763 | 3,565 | 3,472 |
| Natural gas (Mcf/day) | 360,733 | 356,142 | 288,423 |
| Company interest production volumes (BOE/day) | 106,524 | 103,130 | 89,793 |
| **Royalty volumes** | | | |
| Crude oil (bbls/day) | 7,471 | 7,731 | 6,938 |
| Natural gas liquids (bbls/day) | 971 | 775 | 802 |
| Natural gas (Mcf/day) | 59,077 | 55,114 | 42,192 |
| Royalty volumes (BOE/day) | 18,288 | 17,692 | 14,772 |
| **Net production volumes** | | | |
| Crude oil (bbls/day) | 34,168 | 32,477 | 31,312 |
| Natural gas liquids (bbls/day) | 3,792 | 2,790 | 2,670 |
| Natural gas (Mcf/day) | 301,656 | 301,028 | 246,231 |
| Net production volumes (BOE/day) | 88,236 | 85,438 | 75,021 |

## 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. The term netback is calculated as oil and natural gas sales less royalties, production taxes, cash operating expenses and transportation costs.

| **Calculation of Netback** ($ millions) | **Years ended December 31,** | | |
|---|---|---|---|
| | **2015** | **2014** | **2013** |
| Oil and natural gas sales | $ 1,052.4 | $ 1,849.3 | $ 1,616.8 |
| Less: | | | |
| Royalties | (168.0) | (323.1) | (264.3) |
| Production taxes | (50.9) | (81.5) | (70.4) |
| Cash operating expenses[1] | (340.1) | (347.3) | (325.9) |
| Transportation costs | (114.7) | (101.2) | (58.2) |
| Netback before hedging | $ 378.7 | $ 996.2 | $ 898.0 |
| Cash gains/(losses) on derivative instruments | 287.7 | 3.5 | 26.6 |
| Netback after hedging | $ 666.4 | $ 999.7 | $ 924.6 |

(1) Operating costs adjusted to exclude non-cash losses on fixed price electricity swaps of $0.4 million in 2015 and $1.3 million in 2014 and non-cash gains of $0.8 million in 2013.

**"Funds Flow"** is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. 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 Funds Flow** ($ millions) | **Years ended December 31,** | | |
|---|---|---|---|
| | **2015** | **2014** | **2013** |
| Cash flow from operating activities | $ 465.3 | $ 787.2 | $ 766.5 |
| Asset retirement obligation expenditures | 14.9 | 19.4 | 16.6 |
| Changes in non-cash operating working capital | 12.9 | 52.4 | (28.9) |
| Funds flow | $ 493.1 | $ 859.0 | $ 754.2 |

**"Debt to Funds Flow Ratio"** is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The Debt to Funds Flow Ratio is calculated as total debt net of cash, divided by a trailing 12 months of Funds Flow. This measure is not equivalent to Debt to Earnings before Interest, Taxes, Depreciation and Amortization and other non-cash charges ("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 Funds Flow.

| **Calculation of Adjusted Payout Ratio** ($ millions) | **Years ended December 31,** | | |
|---|---|---|---|
| | **2015** | **2014** | **2013** |
| Cash dividends[1] | $ 132.0 | $ 199.3 | $ 170.7 |
| Capital and office expenditures | 497.9 | 818.0 | 687.9 |
| Sub-total | $ 629.9 | $ 1,017.3 | $ 858.6 |
| Funds Flow | $ 493.1 | $ 859.0 | $ 754.2 |
| Adjusted payout ratio (%) | 128% | 118% | 114% |

(1) Cash dividends exclude stock dividend plan proceeds in 2014 and 2013. The stock dividend plan was suspended during 2014.

In addition, the Company uses certain financial measures within the "Overview" and "Liquidity and Capital Resources" sections of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "Senior Debt to EBITDA", "Total Debt to EBITDA", "Total Debt to Capitalization", "maximum debt to consolidated present value of total proved reserves" and "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.

## 2015 FOURTH QUARTER OVERVIEW

Comparing the fourth quarter to the third quarter, production averaged 106,905 BOE/day, a decrease of 3,889 BOE/day from 110,794 BOE/day in the third quarter. The decrease in fourth quarter production related to reduced on-stream activity in Fort Berthold, North Dakota and price driven curtailments of natural gas production in the Marcellus.

We reported a net loss of $625.0 million in the fourth quarter compared to a net loss of $292.7 million in the third quarter. As a result of the continued decline in the trailing twelve month average commodity price, we recorded a non-cash asset impairment of $266.4 million on our oil and natural gas properties and a non-cash valuation allowance of $425.5 million on a portion of our deferred income tax assets. Net income was also impacted by a $41.5 million decline in oil and gas sales revenue and a $50.0 million decrease in total gains on commodity hedges, compared to the third quarter.

Lower realized prices and production volumes contributed to a decline in Funds Flow, which totaled $102.7 million compared to $120.8 million in the third quarter. The impact of decreased oil and gas sales was partially offset by cash gains on commodity hedges of $73.7 million in the fourth quarter, compared to $54.1 million in the third quarter.

### Selected Fourth Quarter Canadian and U.S. Financial Results

| | Three months ended December 31, 2015 | | | Three months ended December 31, 2014 | | |
|---|---|---|---|---|---|---|
| (millions, except per unit amounts) | Canada | U.S. | Total | Canada | U.S. | Total |
| **Average Daily Production Volumes[1]** | | | | | | |
| Crude oil (bbls/day) | 13,790 | 27,345 | 41,135 | 16,073 | 26,745 | 42,818 |
| Natural gas liquids (bbls/day) | 1,771 | 3,321 | 5,092 | 2,315 | 1,172 | 3,487 |
| Natural gas (Mcf/day) | 135,898 | 228,167 | 364,065 | 140,910 | 214,799 | 355,709 |
| Total average daily production (BOE/day) | 38,210 | 68,695 | 106,905 | 41,873 | 63,718 | 105,591 |
| **Pricing[2]** | | | | | | |
| Crude oil (per bbl) | $ 38.11 | $ 45.53 | $ 43.04 | $ 69.25 | $ 69.13 | $ 69.17 |
| Natural gas liquids (per bbl) | 28.77 | 10.13 | 16.61 | 49.10 | 28.98 | 42.34 |
| Natural gas (per Mcf) | 2.46 | 1.55 | 1.89 | 3.84 | 2.87 | 3.25 |
| **Capital Expenditures** | | | | | | |
| Capital spending | $ 26.8 | $ 62.7 | $ 89.5 | $ 65.1 | $ 115.9 | $ 181.0 |
| Acquisitions | 0.7 | 8.1 | 8.8 | – | 1.3 | 1.3 |
| Divestments | 0.9 | (84.1) | (83.2) | (17.9) | – | (17.9) |
| **Netback[3] Before Hedging** | | | | | | |
| Oil and natural gas sales | $ 84.0 | $ 150.2 | $ 234.2 | $ 162.6 | $ 230.9 | $ 393.5 |
| Royalties | (9.0) | (25.8) | (34.8) | (22.5) | (45.8) | (68.3) |
| Production taxes | (1.5) | (10.5) | (12.0) | (2.8) | (17.6) | (20.4) |
| Cash operating expenses | (54.4) | (30.9) | (85.3) | (63.8) | (28.6) | (92.4) |
| Transportation costs | (5.2) | (24.1) | (29.3) | (6.7) | (21.6) | (28.3) |
| Netback before hedging | $ 13.9 | $ 58.9 | $ 72.8 | $ 66.8 | $ 117.3 | $ 184.1 |
| **Other Expenses** | | | | | | |
| Commodity derivative instruments loss/(gain) | $ (31.1) | $ – | $ (31.1) | $ (219.8) | $ – | $ (219.8) |
| General and administrative expense[4] | 10.4 | 8.1 | 18.5 | 17.2 | 7.6 | 24.8 |
| Current tax expense/(recovery) | (0.4) | (0.3) | (0.7) | – | (6.4) | (6.4) |

(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.

Comparing the fourth quarter of 2015 with the same period in 2014:

- Average daily production was 106,905 BOE/day, up 1% or approximately 1,300 BOE/day from 105,591 BOE/day in 2014 despite a reduced capital spending program and asset divestments during the year.
- In Fort Berthold, total production increased 18% or 4,400 bbls/day as a result of our ongoing development program, while gas production in the Marcellus grew by approximately 1,150 BOE/day.
- Capital spending decreased to $89.5 million compared to $181.0 million in 2014 as we improved capital efficiencies and further reduced our spending in response to the ongoing weakness in commodity prices.
- The great majority of our capital investment was focused on our core areas, with spending of $56.4 million on our Fort Berthold crude oil properties, $17.6 million on our Canadian crude oil waterflood properties and $4.6 million on our Marcellus natural gas properties.
- Operating expenses were $85.6 million ($8.71/BOE) compared to $93.9 million ($9.66/BOE) in 2014 as a result of decreased activity and ongoing cost reductions.
- Cash general and administrative ("G&A") expenses were $17.2 million ($1.75/BOE) compared to $25.4 million ($2.62/BOE) in 2014 due to staff reductions and realized cost savings during the quarter, partially offset by one-time severance charges.
- The continued decline in the twelve month average commodity price resulted in non-cash charges for asset impairments on our oil and natural gas properties and valuation allowances on our deferred tax assets of $266.4 million and $425.5 million, respectively. These non-cash charges, along with a $188.8 million decrease in total gains on commodity hedges, contributed to a net loss of $625.0 million compared to net income of $151.7 million in 2014.
- Funds Flow totaled $102.7 million, 52% less than $212.5 million in 2014, primarily due to falling commodity prices over the period. This was despite a slight increase in production and a $27.9 million increase in realized gains on the settlement of commodity hedges.
- During the fourth quarter, we sold certain Canadian shallow gas assets with production of 2,700 BOE/day for nominal proceeds which resulted in a significant reduction of approximately 2,300 gross wells and $35.0 million in future asset retirement obligations.
- In December, we closed the previously announced sale of a portion of our non-operated North Dakota properties for proceeds of $80.4 million, after adjustments.

## 2015 OVERVIEW AND 2016 OUTLOOK

| Summary of Guidance and Results | Original 2015 Guidance | Revised 2015 Guidance | 2015 Results | 2016 Guidance |
|---|---|---|---|---|
| Capital spending ($ millions) | $480 | $510 | $493 | $200 |
| Average annual production (BOE/day) | 93,000 – 100,000 | 106,000 | 106,524 | 90,000 – 94,000 |
| Crude oil and natural gas liquids volumes (bbls/day) | 40,500 – 42,500(1) | 46,000 | 46,402 | 43,000 – 45,000 |
| Average royalty and production tax rate (% of gross sales, before transportation) | 21% | 21% | 21% | 23% |
| Operating expenses (per BOE) | $9.75 | $9.00 | $8.76 | $9.50 |
| Transportation costs (per BOE) | $3.00(2) | $3.00 | $2.95 | $3.30 |
| Cash G&A expenses (per BOE) | $2.40 | $2.20 | $2.09 | $2.10 |

(1) Original crude oil and liquids guidance was 42% to 44%. Volume above has been calculated using the approximate midpoint of the original average annual production guidance.
(2) Transportation guidance issued in the first quarter following the January 1, 2015 reclassification of gathering costs from operating expenses to transportation costs. Refer to "Operating Expenses" and "Transportation Costs" sections for additional details.

### 2015 Overview

Annual average production in 2015 was 106,524 BOE/day, exceeding our revised guidance of 106,000 BOE/day despite lower capital spending. Our crude oil and liquids production averaged 46,402 BOE/day, also beating our revised guidance of 46,000 BOE/day.

Capital spending totaled $493.4 million, below our revised target of $510 million due to cost savings and reduced activity in the fourth quarter in response to the continued decline in commodity prices.

Operating expenses and transportation costs beat guidance at $8.76/BOE and $2.95/BOE, respectively, compared to revised guidance of $9.00/BOE and $3.00/BOE, respectively. Operating cost savings were a result of ongoing cost structure improvements. Cash G&A expenses were $2.09/BOE, also beating our guidance of $2.20/BOE, due to reduced staff levels and cost savings and despite $11.5 million in one-time severance charges.

We reported a net loss of $1,523.4 million compared to net income of $299.1 million in 2014. The reported net loss was primarily a result of non-cash asset impairment charges of $1,352.4 million and a non-cash valuation allowance on our deferred income tax asset of $443.7 million, as well as lower oil and gas sales revenue. Funds Flow decreased to $493.1 from $859.0 million, mainly due to lower oil and gas sales revenue offset by $287.7 million in realized gains on the settlement of commodity derivatives.

We continued to focus our portfolio during 2015, selling assets with production of approximately 6,170 BOE/day for net divestment proceeds of $286.6 million. This included the fourth quarter divestment of certain non-core Canadian shallow gas assets with production of 2,700 BOE/day for nominal proceeds which resulted in a significant reduction to future asset retirement obligations.

Despite a decrease in our oil and gas sales revenue, we have continued to maintain our financial flexibility through an ongoing focus on cost efficiencies, the success of our non-core asset divestment program, disciplined capital spending and a reduction in dividends. At December 31, 2015, our total debt, net of cash, was $1,216.2 million compared to $1,134.9 million at December 31, 2014. The increase was entirely due to the impact of the weaker Canadian dollar on our U.S. dollar denominated debt that is translated to Canadian dollars for reporting. We repaid $103.2 million of our senior notes during the year and increased the amount drawn on our bank credit facility by a modest $6.6 million, ending the year with approximately 11% of our $800 million bank credit facility drawn. At December 31, 2015 we were in compliance with all of our debt covenants. Our Senior Debt to EBITDA ratio was 2.2x and our Debt to Funds Flow Ratio was 2.5x.

**2016 Outlook**

Similar to 2015, our focus for 2016 will be on financial sustainability, with an aim to preserve our flexibility and balance sheet strength in both the near and long-term, while positioning to re-initiate growth should commodity prices improve in 2017. In response to the challenging commodity price environment, we have reduced our capital spending to $200 million for 2016 to protect our balance sheet. We plan to continue to defer capital spending across our core areas, conserving our opportunities until we see an improvement in commodity prices. In addition, we are revising our monthly dividend to $0.01 per share, effective with our April dividend payment.

Subsequent to year end, we entered into two agreements to sell Canadian natural gas properties located in Alberta with production of approximately 5,400 BOE/day for proceeds of $193.0 million, before closing costs. Upon closing one of the transactions in January we received $183.0 million in proceeds, and we expect the second transaction to close during the first quarter of 2016. Proceeds were used to repay outstanding amounts on our bank credit facility as well as a portion of our outstanding senior notes. The remaining proceeds will be directed to our capital spending program. As a result of these divestments, we expect to record a gain of approximately $145 million in the first quarter which will improve our EBITDA. Based on our 2016 guidance price assumptions, we do not expect to exceed our Debt to EBITDA ratio during the year. However, should current commodity prices persist we would expect to begin negotiations with our lenders to amend our covenants towards the end of 2016. There are a number of measures that may be taken to further protect our balance sheet, including asset divestments, additional reductions to capital spending and equity issuances.

We expect average production for 2016 to be between 90,000 – 94,000 BOE/day, with crude oil and natural gas liquids production of 43,000 – 45,000 bbls/day. The decrease from 2015 production levels is a result of the full year impact of 6,170 BOE/day of asset divestments during 2015, 5,400 BOE/day of Deep Basin property divestments during the first quarter of 2016 and a reduction in capital spending.

We expect operating expenses to be approximately 6% lower than 2015 levels, although on a per BOE basis they are expected to increase to $9.50/BOE in 2016 as a result of lower production and the impact of a weaker Canadian dollar on our U.S. operating costs. We expect our cash G&A expense to decrease on a total dollar basis due to the staff reductions during 2015 and continued cost saving initiatives. However, on a per BOE basis, cash G&A expenses are expected to be $2.10/BOE as a result of lower production.

Our commodity hedging program will also help protect our Funds Flow and balance sheet in 2016. At February 3, 2016, we have approximately 36% of our forecasted 2016 crude oil production, after royalties, hedged through a combination of swaps and three way collars. We also have a combination of swaps and three way collars on approximately 28% of forecasted natural gas production, after royalties.

## RESULTS OF OPERATIONS

### Production

| Average Daily Production Volumes | 2015 | 2014 | 2013 |
|---|---|---|---|
| Crude oil (bbls/day) | 41,639 | 40,208 | 38,250 |
| Natural gas liquids (bbls/day) | 4,763 | 3,565 | 3,472 |
| Natural gas (Mcf/day) | 360,733 | 356,142 | 288,423 |
| Total daily sales (BOE/day) | 106,524 | 103,130 | 89,793 |

Production for 2015 averaged 106,524 BOE/day, exceeding our revised guidance of 106,000 BOE/day and increasing 3% from 2014. Crude oil and liquids volumes increased 6% to 46,402 bbls/day, beating our revised crude oil and liquids guidance of 46,000 bbls/day. The increase was primarily due to growth in our U.S. production, which more than offset divestments and a decline in Canadian production.

Total crude oil production increased from the prior year due to our continued development program in Fort Berthold, where our total production increased approximately 6,000 bbls/day or 28% compared to the prior year. The growth in our U.S. oil production offset a 9% decrease in Canadian crude oil volumes related to the second and third quarter divestments of Canadian oil properties. Our 2015 natural gas production increased by 1% to 360,733 Mcf/day, comprised of growth of 14,500 Mcf/day or 8% in our Marcellus natural gas production offset by the decline in Canadian natural gas production over the same period.

Our production mix for 2015 was 44% crude oil and natural gas liquids and 56% natural gas, compared to 42% and 58%, respectively, in 2014.

In 2014, production increased 15% over 2013 to average 103,130 BOE/day. Our 2014 crude oil production increased 5% from the prior year due to growth in our Fort Berthold crude oil volumes. Our natural gas production increased 23% to 356,142 Mcf/day due to our development program in the Marcellus along with the fourth quarter 2013 acquisition of additional working interests in our Marcellus properties. This was despite curtailments in the Marcellus during the second half of 2014 and the sale of 3,500 BOE/day of non-core assets.

*2016 Guidance*

We expect annual average production for 2016 of 90,000 – 94,000 BOE/day including 43,000 – 45,000 bbls/day of crude oil and natural gas liquids. This guidance includes the full year impact of our 2015 divestments, including the fourth quarter sales of non-operated North Dakota properties with projected 2016 production of 1,000 BOE/day and Canadian shallow gas assets with production of 2,700 BOE/day. This guidance also includes the first quarter 2016 sale of certain Deep Basin natural gas properties located in Alberta with production of approximately 5,400 BOE/day.

## Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, Funds Flow and financial condition. The following table summarizes our average selling prices, benchmark prices and differentials:

| **Pricing** (average for the period) | **2015** | **2014** | **2013** |
|---|---|---|---|
| **Benchmarks** | | | |
| WTI crude oil (US$/bbl) | $ 48.80 | $ 93.00 | $ 97.97 |
| AECO natural gas – monthly index ($/Mcf) | 2.77 | 4.42 | 3.16 |
| AECO natural gas – daily index ($/Mcf) | 2.69 | 4.51 | 3.17 |
| NYMEX natural gas – last day (US$/Mcf) | 2.66 | 4.41 | 3.65 |
| US/CDN exchange rate | 1.28 | 1.10 | 1.03 |
| **Enerplus selling price**(1) | | | |
| Crude oil ($/bbl) | $ 48.43 | $ 86.28 | $ 85.05 |
| Natural gas liquids ($/bbl) | 18.06 | 51.72 | 53.20 |
| Natural gas ($/Mcf) | 2.15 | 3.94 | 3.42 |
| **Average differentials** | | | |
| MSW Edmonton – WTI (US$/bbl) | $ (3.93) | $ (7.17) | $ (7.57) |
| WCS Hardisty – WTI (US$/bbl) | (13.52) | (19.40) | (25.20) |
| Brent Futures (ICE) – WTI (US$/bbl) | 4.89 | 6.51 | 10.77 |
| AECO monthly – NYMEX (US$/Mcf) | (0.50) | (0.41) | (0.58) |
| **Enerplus realized differentials**(1) | | | |
| Canada crude oil – WTI (US$/bbl) | $ (13.34) | $ (17.36) | $ (21.46) |
| Canada natural gas – NYMEX (US$/Mcf) | (0.44) | (0.34) | (0.48) |
| Bakken crude oil – WTI (US$/bbl) | (9.44) | (12.94) | (10.13) |
| Marcellus natural gas – NYMEX (US$/Mcf) | (1.37) | (1.43) | (0.34) |

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

### CRUDE OIL AND NATURAL GAS LIQUIDS

Our realized crude oil price averaged $48.43/bbl in 2015, which was 44% lower than 2014 and in line with changes in benchmark prices over the same period. WTI crude oil prices fell by 48% compared to 2014 due to the continued oversupply of crude oil into the global market that resulted in a substantial increase in oil inventories throughout the year. Improved realized crude oil differentials and a weaker Canadian dollar protected us from the full impact of weaker WTI prices during the year.

Our realized price differentials to WTI improved by 27% in the U.S. and 23% in Canada compared to 2014. Light sweet differentials strengthened due to overall weakness in WTI prices as well as the reversal of the Line 9 pipeline to Sarnia, Ontario by the end of the year. Heavy crude oil differentials benefited from weaker WTI prices throughout 2015 as well as production losses due to forest fires in northern Alberta and other unplanned maintenance earlier in the year.

Our realized price for natural gas liquids fell by 65% to average $18.06/bbl in 2015. This is in-line with benchmark prices for both U.S. and Canadian liquids, which fell by an average of 55% and 62%, respectively, due to weaker oil prices and the continued oversupply of liquids in North America.

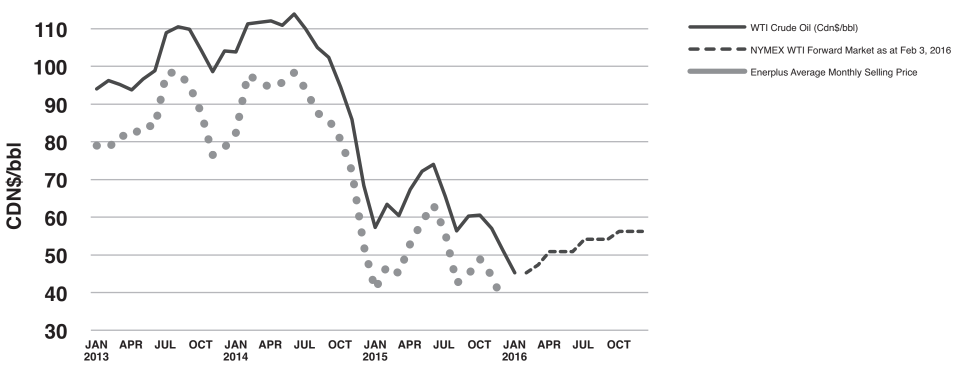
### NATURAL GAS

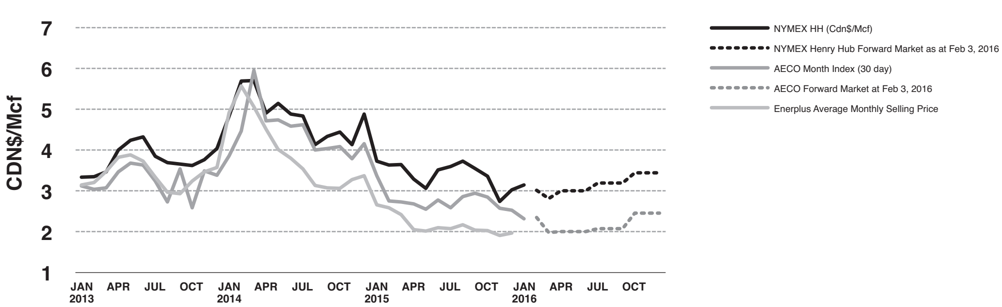
Our realized natural gas price averaged $2.15/Mcf in 2015, which was 45% lower than 2014 and slightly lower than benchmark prices over the same period. Both NYMEX and AECO prices fell by approximately 40% compared to 2014 in response to continued high production and inventory levels in North America. Our overall realized natural gas price underperformed changes in NYMEX prices in 2015 as our Marcellus assets contributed a larger share of our total gas production at realized prices with a significant discount to NYMEX as a result of ongoing industry pipeline capacity limitations.

Tennessee Gas Pipeline Zone 4 – 300 Leg and Transco Leidy monthly benchmark differentials averaged US$1.55/Mcf below NYMEX and monthly differentials at Dominion South averaged US$1.22/Mcf below NYMEX. This resulted in our average Marcellus realized price differential of US$1.37/Mcf below NYMEX, a 4% improvement from last year.

We expect our realized Marcellus differentials in 2016 to improve due to reduced industry spend and the continued build out of regional take-away capacity, as well as additional pipeline capacity secured. We have entered into a binding contract for 30,000 Mcf/day of transportation capacity for an 11 year term, reducing to 15,000 Mcf/day of capacity for an additional 9 years on the Tennessee Gas Pipeline that will provide egress into markets south of the Marcellus producing region commencing on August 1, 2016.

*Monthly Crude Oil and Natural Gas Prices*




## FOREIGN EXCHANGE

The Canadian dollar weakened against the U.S. dollar throughout 2015, averaging 1.28 US/CDN and closing the year at 1.38 US/CDN. This was driven primarily by the overall weakness in the Canadian economy as a result of falling commodity prices and the Bank of Canada lowering interest rates. Downward pressure continued in early 2016, with the Canadian dollar nearing a thirteen year low of 1.46 US/CDN mid-January, before rebounding somewhat following the Bank of Canada's decision to keep interest rates unchanged. 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 weaker Canadian dollar also increases our U.S. dollar denominated costs, capital spending and the cost of our U.S. dollar denominated senior notes.

**Price Risk Management**

We have a price risk management program that considers our overall financial position, the economics of our capital program and potential acquisitions. Since our 2015 third quarter report, we have added additional floor protection on a portion of our natural gas production for 2016 and restructured our crude oil hedging program to provide additional short term protection, effectively adding 6,000 bbls/day of crude oil swaps during the first quarter of 2016.

As of February 3, 2016 we have hedged approximately 11,000 bbls/day of our expected net crude oil production for 2016 through a combination of swaps and three way collars, which represents approximately 36% of our 2016 forecasted net oil production, after royalties. A significant portion of this protection is for the first quarter given the short term risks we see in the market. For the first quarter of 2016 we have hedged 17,000 bbls/day, which represents approximately 55% of our 2016 forecasted net oil production, after royalties. During the second quarter of 2016 we have hedged 11,000 bbls/day, which represents approximately 36% of our 2016 forecasted net oil production, after royalties. For the second half of 2016 we have hedged 8,000 bbls/day, which represents approximately 26% of our 2016 forecasted net oil production, after royalties. Price protection levels are shown in the table below. Note that when WTI prices settle below the sold put strike price in any given month, the collars provide protection of approximately US$14/bbl above WTI index prices. Overall, we expect our crude oil related hedge contracts to protect a significant portion of our Funds Flow during 2016.

As of February 3, 2016 we have downside protection on approximately 62,500 Mcf/day of our expected net natural gas production for 2016 consisting of a combination of NYMEX swaps and collars. This represents approximately 28% of our 2016 forecasted natural gas production after royalties. Price protection levels are shown in the table below. Note that when NYMEX prices settle below US$2.50/Mcf in any given month, the collars provide protection of approximately US$0.50/Mcf above NYMEX index prices.

The following is a summary of our financial contracts in place at February 3, 2016, expressed as a percentage of our anticipated net 2016 production volumes:

| | WTI Crude Oil (US$/bbl)[1] | | | NYMEX Natural Gas (US$/Mcf)[1] | | |
|---|---|---|---|---|---|---|
| | Jan 1, 2016 – Mar 31, 2016 | Apr 1, 2016 – Jun 30, 2016 | Jul 1, 2016 – Dec 31, 2016 | Jan 1, 2016 – Mar 31, 2016 | Apr 1, 2016 – Oct 31, 2016 | Nov 1, 2016 – Dec 31, 2016 |
| **Downside Protection Swaps** | | | | | | |
| Sold Swaps | $ 55.82 | $ 64.28 | – | $ 2.48 | $ 2.53 | $ 2.48 |
| % | 29% | 10% | – | 7% | 23% | 11% |
| **Downside Protection Collars** | | | | | | |
| Sold Puts | $ 50.13 | $ 50.13 | $ 49.78 | $ 2.50 | $ 2.50 | $ 2.50 |
| % | 26% | 26% | 26% | 11% | 11% | 11% |
| Purchased Puts | $ 64.38 | $ 64.38 | $ 63.98 | $ 3.00 | $ 3.00 | $ 3.00 |
| % | 26% | 26% | 26% | 11% | 11% | 11% |
| Sold Calls | $ 79.38 | $ 79.38 | $ 79.63 | $ 3.75 | $ 3.75 | $ 3.75 |
| % | 26% | 26% | 26% | 11% | 11% | 11% |

(1) Based on weighted average price (before premiums), assuming average annual production of 92,000 BOE/day for 2016, less royalties and production taxes of 23% in aggregate.

During 2014, we entered into foreign exchange costless collars on US$24 million per month to hedge a floor exchange rate on a portion of our U.S. dollar denominated oil and natural gas sales and to participate in some upside in the event the Canadian dollar weakened. Under these contracts, if the monthly foreign exchange rate settles above the ceiling rate the conditional ceiling is used to determine the settlement amount. During the second quarter of 2015, we entered into U.S. dollar forward exchange contracts on US$6 million per month at an exchange rate of US/CDN 1.20 to partially mitigate our losses on these collars. For the second half of 2015, we effectively had US$18 million per month hedged for 2015 at an average US/CDN floor of 1.1088, a ceiling of 1.1845 and a conditional ceiling of 1.1263. We recorded realized foreign exchange losses of $39.2 million on these contracts during 2015 (2014 – $0.7 million gain).

During 2015, we recorded realized foreign exchange gains of $39.9 million and $3.3 million, respectively, on the unwind of our US$175 million foreign exchange swap and the final settlement of our US$54 million senior note and the corresponding foreign exchange swap. We do not have any foreign exchange contracts in place for 2016.

## ACCOUNTING FOR PRICE RISK MANAGEMENT

| **Commodity Risk Management Gains/(Losses)**<br>($ millions) | **2015** | **2014** | **2013** |
|---|---|---|---|
| Cash gains/(losses): | | | |
| Crude oil | $ 217.2 | $ 7.0 | $ 24.4 |
| Natural gas | 70.5 | (3.5) | 2.2 |
| Total cash gains | $ 287.7 | $ 3.5 | $ 26.6 |
| Non-cash gains/(losses): | | | |
| Change in fair value – crude oil | $ (99.8) | $ 182.0 | $ (65.5) |
| Change in fair value – natural gas | (45.2) | 48.9 | (3.0) |
| Total non-cash gains/(losses) | $ (145.0) | $ 230.9 | $ (68.5) |
| Total gains/(losses) | $ 142.7 | $ 234.4 | $ (41.9) |

| (Per BOE) | **2015** | **2014** | **2013** |
|---|---|---|---|
| Total cash gains | $ 7.40 | $ 0.09 | $ 0.81 |
| Total non-cash gains/(losses) | (3.73) | 6.14 | (2.09) |
| Total gains/(losses) | $ 3.67 | $ 6.23 | $ (1.28) |

During 2015, we realized cash gains of $217.2 million on our crude oil contracts and $70.5 million on our natural gas contracts. In comparison, during 2014 and 2013 we realized cash gains of $7.0 million and $24.4 million, respectively, on our crude oil contracts and cash losses of $3.5 million and cash gains of $2.2 million, respectively, on our natural gas contracts. The cash gains in each year were due to contracts which provided floor protection above market prices, while cash losses were a result of natural gas prices rising above our fixed price swap positions.

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. The fair value of our crude oil and natural gas contracts represented net gain positions of $67.4 million and $4.0 million, respectively, at December 31, 2015, and $167.2 million and $49.2 million, respectively, at December 31, 2014. The change in fair value of our crude oil and natural gas contracts represented losses of $99.8 million and $45.2 million, respectively, during 2015 and gains of $182.0 million and $48.9 million, respectively, during 2014.

### Revenues

| ($ millions) | **2015** | **2014** | **2013** |
|---|---|---|---|
| Oil and natural gas sales | $ 1,052.4 | $ 1,849.3 | $ 1,616.8 |
| Royalties | (168.0) | (323.1) | (264.3) |
| Oil and natural gas sales, net of royalties | $ 884.4 | $ 1,526.2 | $ 1,352.5 |

Oil and natural gas sales revenue for 2015 totaled $1,052.4 million, a decrease of 43% from $1,849.3 million in 2014. The decrease in revenues was due to the weakness in commodity prices, which was offset somewhat by the growth in production volumes.

In 2014, oil and natural gas sales revenue increased to $1,849.3 million compared to $1,616.8 million in 2013. Oil revenues grew 6% during the year driven by an increase in production, while natural gas sales increased 44% due to higher realized prices and increased production.

### Royalties and Production Taxes

| ($ millions, except per BOE amounts) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Royalties | $ 168.0 | $ 323.1 | $ 264.3 |
| Per BOE | $ 4.32 | $ 8.58 | $ 8.06 |
| Production taxes | $ 50.9 | $ 81.5 | $ 70.4 |
| Per BOE | $ 1.31 | $ 2.17 | $ 2.15 |
| Royalties and production taxes | $ 218.9 | $ 404.6 | $ 334.7 |
| Per BOE | $ 5.63 | $ 10.75 | $ 10.21 |
| Royalties and production taxes (% of oil and natural gas sales, before transportation) | 21% | 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 not sensitive to commodity price levels.

Royalties and production taxes decreased to $218.9 million in 2015 from $404.6 million in 2014 primarily due to decreased realized crude oil and natural gas prices. Royalties and production taxes were in line with our guidance for 2015, averaging 21% of oil and natural gas sales, before transportation.

Royalties and production taxes increased to $404.6 million in 2014 from $334.7 million in 2013 primarily due to increased production from our higher royalty rate U.S. properties. Royalties and production taxes averaged 22% of oil and natural gas sales, before transportation.

*2016 Guidance*

We expect royalty and production taxes in 2016 to average 23% of our oil and gas sales, before transportation. The increase compared to 2015 is due to the higher percentage of U.S. production in 2016 as a result of continued investment as well as our divestment of Canadian properties during 2015 and early 2016. At this time, we do not expect the recently announced Alberta modernized royalty framework to significantly impact our Canadian royalties when it becomes effective in 2017. However, we continue to actively monitor the changes being proposed.

### Operating Expenses

| ($ millions, except per BOE amounts) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Operating Expenses | $ 340.5 | $ 348.6 | $ 325.1 |
| Per BOE | $ 8.76 | $ 9.26 | $ 9.92 |

Effective January 1, 2015 we reclassified Marcellus gathering costs from operating expenses to transportation costs. These charges relate to pipeline costs paid to third parties to transport saleable natural gas from the lease to downstream points of sale. This is a presentation change with no impact on our netback, Funds Flow or net income. All comparative periods have been presented to conform to the current period presentation.

Operating expenses during 2015 were $8.76/BOE, beating our revised guidance of $9.00/BOE primarily due to continued cost reductions and annual production exceeding guidance. Operating expenses totaled $340.5 million compared to $348.6 million ($9.26/BOE) in 2014. The improvement resulted mainly from successful cost saving initiatives and a continued increase in the U.S. weighting of production, which has lower operating expense metrics. This was offset in part by the impact of a weaker Canadian dollar on our U.S. dollar denominated operating expenses.

In 2014, operating expenses totaled $348.6 million ($9.26/BOE) compared to $325.2 million ($9.92/BOE) in 2013. The decrease on a per unit basis was primarily due to a significant increase in U.S. production with lower operating expenses, offset in part by the impact of a weaker Canadian dollar and an increase in non-cash hedging losses on our fixed price electricity swaps.

*2016 Guidance*

We expect operating expenses of $9.50/BOE in 2016. The increase from 2015 on a per BOE basis is due to lower production volumes along with the impact of a weaker Canadian dollar on our U.S. operating costs.

### Transportation Costs

| ($ millions, except per BOE amounts) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Transportation costs | $ 114.7 | $ 101.2 | $ 58.2 |
| Per BOE | $ 2.95 | $ 2.69 | $ 1.77 |

As previously discussed under operating expenses, we have reclassified Marcellus gathering costs from operating expenses to transportation costs. This is a presentation change with no impact on our netback, Funds Flow or net income. All comparative periods have been presented to conform with the current period presentation.

Transportation costs for 2015 were $114.7 million ($2.95/BOE) compared to $101.2 million ($2.69/BOE) in 2014 and $58.2 million ($1.77/BOE) in 2013. The increase in transportation costs over the past two years is a result of increasing U.S. production and costs associated with securing U.S. pipeline capacity. The impact of a weakening Canadian dollar on our U.S. transportation costs further increased our total reported expense.

*2016 Guidance*

We expect transportation costs of $3.30/BOE in 2016. The increase from 2015 is due to the higher percentage of U.S. production in 2016 along with the impact of a weaker Canadian dollar on our U.S. 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. Certain prior period amounts have been reclassified to conform with current period presentation.

| | Year ended December 31, 2015 | | |
|---|---|---|---|
| **Netbacks by Property Type** | **Crude Oil** | **Natural Gas** | **Total** |
| Average Daily Production | 49,069 BOE/day | 344,730 Mcfe/day | 106,524 BOE/day |
| Netback[1] $ per BOE or Mcfe | (per BOE) | (per Mcfe) | (per BOE) |
| Oil and natural gas sales | $ 43.67 | $ 2.15 | $ 27.07 |
| Royalties and production taxes | (10.54) | (0.24) | (5.63) |
| Cash operating expenses | (11.98) | (1.00) | (8.75) |
| Transportation costs | (1.84) | (0.65) | (2.95) |
| Netback before hedging | $ 19.31 | $ 0.26 | $ 9.74 |
| Cash gains/(losses) | 12.13 | 0.56 | 7.40 |
| Netback after hedging | $ 31.44 | $ 0.82 | $ 17.14 |
| Netback before hedging ($ millions) | $ 345.7 | $ 33.0 | $ 378.7 |
| Netback after hedging ($ millions) | $ 562.9 | $ 103.5 | $ 666.4 |

| Netbacks by Property Type | Year ended December 31, 2014 Crude Oil | Natural Gas | Total |
|---|---|---|---|
| Average Daily Production | 45,225 BOE/day | 347,430 Mcfe/day | 103,130 BOE/day |
| Netback[1] $ per BOE or Mcfe | (per BOE) | (per Mcfe) | (per BOE) |
| Oil and natural gas sales | $ 79.12 | $ 4.28 | $ 49.13 |
| Royalties and production taxes | (19.78) | (0.61) | (10.75) |
| Cash operating expenses | (11.76) | (1.21) | (9.23) |
| Transportation costs | (1.89) | (0.55) | (2.69) |
| Netback before hedging | $ 45.69 | $ 1.91 | $ 26.46 |
| Cash gains/(losses) | 0.42 | (0.03) | 0.09 |
| Netback after hedging | $ 46.11 | $ 1.88 | $ 26.57 |
| Netback before hedging ($ millions) | $ 754.3 | $ 241.9 | $ 996.2 |
| Netback after hedging ($ millions) | $ 761.3 | $ 238.4 | $ 999.7 |

| Netbacks by Property Type | Year ended December 31, 2013 Crude Oil | Natural Gas | Total |
|---|---|---|---|
| Average Daily Production | 43,402 BOE/day | 278,346 Mcfe/day | 89,793 BOE/day |
| Netback[1] $ per BOE or Mcfe | (per BOE) | (per Mcfe) | (per BOE) |
| Oil and natural gas sales | $ 77.15 | $ 3.88 | $ 49.33 |
| Royalties and production taxes | (18.22) | (0.45) | (10.21) |
| Cash operating expenses | (11.63) | (1.39) | (9.95) |
| Transportation costs | (1.26) | (0.38) | (1.77) |
| Netback before hedging | $ 46.04 | $ 1.66 | $ 27.40 |
| Cash gains/(losses) | 1.54 | 0.02 | 0.81 |
| Netback after hedging | $ 47.58 | $ 1.68 | $ 28.21 |
| Netback before hedging ($ millions) | $ 729.4 | $ 168.6 | $ 898.0 |
| Netback after hedging ($ millions) | $ 753.8 | $ 170.8 | $ 924.6 |

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

Our crude oil properties accounted for 91% of our corporate netback before hedging in 2015 compared to 76% and 81% in 2014 and 2013, respectively.

During 2015, crude oil netbacks per BOE and natural gas netbacks per Mcfe decreased compared to 2014 primarily due to lower realized prices. Our 2014 crude oil netbacks per BOE decreased marginally while natural gas netbacks per Mcfe increased primarily due to improved realized prices compared to 2013.

### General and Administrative 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") and our stock option plan. See Note 10 and Note 14 to the Financial Statements for further details.

| ($ millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Cash: | | | |
| G&A expense | $ 81.3 | $ 83.5 | $ 83.2 |
| Share-based compensation | 0.9 | (1.2) | 23.3 |
| Non-Cash: | | | |
| Share-based compensation | 19.6 | 13.4 | 9.2 |
| Equity swap loss/(gain) | 2.1 | 9.3 | (5.4) |
| Total G&A expenses | $ 103.9 | $ 105.0 | $ 110.3 |

| (Per BOE) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Cash: | | | |
| G&A expense | $ 2.09 | $ 2.22 | $ 2.54 |
| Share-based compensation | 0.02 | (0.03) | 0.71 |
| Non-Cash: | | | |
| Share-based compensation | 0.51 | 0.36 | 0.28 |
| Equity swap loss/(gain) | 0.05 | 0.24 | (0.17) |
| Total G&A expenses | $ 2.67 | $ 2.79 | $ 3.36 |

Our 2015 cash G&A expenses totaled $81.3 million ($2.09/BOE), beating our guidance of $2.20/BOE and lower than $83.5 million ($2.22/BOE) in 2014. The decrease in cash G&A expenses compared to 2014 was primarily due to a reduction in staff levels of approximately 20% offset by one-time severance charges of $11.5 million. Cash SBC expense was $0.9 million ($0.02/BOE) in 2015 compared to a recovery of $1.2 million ($0.03/BOE) in 2014, and included a cash loss of $0.5 million on the settlement of our LTI hedges (2014 – $3.1 million gain). We recorded non-cash SBC of $19.6 million ($0.51/BOE) in 2015 compared to $13.4 million ($0.36/BOE) in 2014. The increase in non-cash SBC was a result of additional grants issued under the treasury-settled LTI plans rather than the cash-settled plans.

Our 2014 cash G&A expenses were $83.5 million ($2.22/BOE) compared to $83.2 million ($2.54/BOE) in 2013. On a per BOE basis, costs decreased by 13% due to higher production volumes. Cash SBC was a recovery of $1.2 million ($0.03/BOE) in 2014 compared to a charge of $23.3 million ($0.71/BOE) in 2013 due to a decrease in share price resulting in a recovery of costs previously expensed. Non-cash SBC was $13.4 million ($0.36/BOE) in 2014, an increase from $9.2 million ($0.28/BOE) in 2013 as a result of our first grants under the amended treasury-settled LTI plans. Previous non-cash amounts reported related only to our stock option plan.

We have hedged a portion of the outstanding cash-settled units under our LTI plans. As a result of the decrease in our share price we recorded a non-cash mark-to-market loss of $2.1 million on these hedges in 2015 (2014 – $9.3 million loss; 2013 – $5.4 million gain). As of December 31, 2015, we have 470,000 units hedged at a weighted average price of $16.89/share.

*2016 Guidance*

We expect our cash G&A expense to decrease on a total dollar basis due to the staff reductions during 2015 and continued cost saving initiatives. However, on a per BOE basis, cash G&A costs are expected to be $2.10/BOE as a result of lower production.

### Interest Expense

| ($ millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Interest on senior notes and bank facility | $ 66.5 | $ 62.2 | $ 56.7 |
| Non-cash interest expense | 0.9 | 1.6 | 1.6 |
| Total interest expense | $ 67.4 | $ 63.8 | $ 58.3 |

Interest on our senior notes and bank credit facility in 2015 increased to $67.4 million compared to $63.8 million in 2014 and $58.3 million in 2013. Interest expense increased in 2015 due to the impact of a weaker Canadian dollar on our U.S. dollar denominated interest payments and an increased weighting of senior notes with higher interest rates compared to our bank credit facility following our US$200.0 million private placement of senior notes in September 2014.

Non-cash amounts recorded in 2015 relate to the amortization of deferred financing charges. Prior year amounts include unrealized gains resulting from the change in fair value of our interest rate swaps and unrealized losses on the interest component of our cross currency interest rate swap ("CCIRS") (2014 – $0.6 million; 2013 – $0.8 million). See Note 11 to the Financial Statements for further details.

At December 31, 2015, approximately 93% of our debt was based on fixed interest rates and 7% on floating interest rates, with weighted average interest rates of 5.2% and 2.5%, respectively.

### Foreign Exchange

| ($ millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Realized loss/(gain) | $ (8.7) | $ 11.2 | $ 17.6 |
| Unrealized loss/(gain) | 182.6 | 45.9 | (8.3) |
| Total foreign exchange loss/(gain) | $ 173.9 | $ 57.1 | $ 9.3 |
| US/CDN exchange rate | 1.28 | 1.10 | 1.03 |

We recorded a net foreign exchange loss of $173.9 million in 2015 compared to losses of $57.1 million and $9.3 million in 2014 and 2013, respectively. Our foreign exchange exposure relates to fluctuations in the Canadian to U.S. dollar exchange rate. At December 31, 2015 the Canadian dollar had weakened approximately 19% against the U.S. dollar compared to the prior year end (December 31, 2014 – 9%; December 31, 2013 – 7%).

Realized gains or losses result from day-to-day transactions denominated in foreign currencies. In 2015, we recorded a realized foreign exchange gain of $8.7 million, largely due to a gain of $39.9 million on the unwind of our US$175 million foreign exchange swaps and a gain of $3.3 million on the final settlement of our US$54 million senior note and the corresponding foreign exchange swap. These gains were offset by cumulative losses of $39.2 million on our foreign exchange collars with final settlements in December 2015.

Unrealized losses include the translation of our U.S. dollar denominated debt and working capital. Unrealized losses increased year over year due to the weakening of the Canadian dollar against the U.S. dollar.

Foreign exchange in 2014 and 2013 was impacted by the annual settlement of our CCIRS. Each year, upon settlement of the swap, we realized a foreign exchange loss (2014 – $15.8 million; 2013 – $17.8 million) and a corresponding unrealized gain to remove the mark-to-market position previously recorded on the balance sheet. The final settlement of the swap occurred in June 2014. See Note 12 to the Financial Statements for further details.

### Capital Investment

| ($ millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Capital spending | $ 493.4 | $ 811.0 | $ 681.4 |
| Office capital | 4.5 | 7.0 | 6.5 |
| Sub-total | 497.9 | 818.0 | 687.9 |
| Property and land acquisitions | $ 9.5 | $ 18.5 | $ 244.8 |
| Property divestments | (286.6) | (203.6) | (365.1) |
| Sub-total | (277.1) | (185.1) | (120.3) |
| Total | $ 220.8 | $ 632.9 | $ 567.6 |

*2015*

Capital spending in 2015 totaled $493.4 million, below our revised guidance of $510 million as we slowed spending in the fourth quarter in response to continued weakness in commodity prices. We invested $302.3 million on our Fort Berthold crude oil properties, $115.7 million on our Canadian crude oil properties, $32.2 million on our Marcellus assets and $40.4 million on our Deep Basin properties in Canada. Through our capital program in 2015 we added 42 MMBOE of gross proved plus probable reserves, replacing 108% of our 2015 production at a finding and development cost of $8.44/BOE, before accounting for acquisitions and divestments.

During 2015, we recorded net divestment proceeds of $286.6 million. In Canada, we divested of assets for combined proceeds of $198.9 million with production of approximately 4,900 BOE/day, including the sale of our Pembina waterflood assets and the fourth quarter sale of certain non-core shallow gas assets with production of 2,700 BOE/day for nominal proceeds. These divestments resulted in a $48.7 million reduction to future asset retirement obligations. In the U.S., we divested of assets for combined proceeds of $87.7 million with production of approximately 1,250 BOE/day, including the sale of our non-operated North Dakota properties for proceeds of $80.4 million, after closing costs, and our operated Marcellus assets for proceeds of $3.5 million. Property and land acquisitions in 2015 totaled $9.5 million and included minor acquisitions of leases and undeveloped land in the U.S. as well as adjustments pertaining to prior period property acquisitions.

On January 11, 2016 we entered into two agreements to sell additional Canadian Deep Basin properties located in Alberta with production of approximately 5,400 BOE/day for proceeds of $193.0 million, of which $183.0 million has been received with the closing of one transaction. We expect the second transaction to close during the first quarter of 2016.

*2014*

Capital spending in 2014 totaled $811.0 million and included spending of $343.7 million on our Fort Berthold crude oil properties, $176.6 million on our Canadian crude oil properties, $158.8 million on our Marcellus assets and $124.5 million on our deep gas properties in Canada. Through our capital program in 2014 we added 75 MMBOE of gross proved plus probable reserves, replacing over 200% of our 2014 production.

Property and land acquisitions in 2014 totaled $18.5 million and included several minor acquisitions across our core areas.

Property divestments in 2014 totaled $203.6 million. In Canada we divested of natural gas properties in the Deep Basin area with production of approximately 3,100 BOE/day for proceeds of $91.0 million and recognized the remaining $65.8 million of proceeds on the 2013 sale of our undeveloped Montney acreage. During the first quarter, we sold our gross overriding royalty interest in the Jonah natural gas property in Wyoming with production of approximately 400 BOE/day for proceeds of $44.0 million, after closing adjustments.

*2013*

Capital spending in 2013 totaled $681.4 million and included spending of $314.9 million on our Fort Berthold crude oil properties, $172.9 million on our Canadian crude oil properties, $78.7 million developing our Marcellus assets and $89.3 million on our deep gas properties in Canada. Through our capital program in 2013 we added 76 MMBOE of gross proved plus probable reserves, replacing over 238% of our 2013 production.

Property and land acquisitions in 2013 totaled $244.8 million. The most noteworthy transactions included the additional working interests we acquired in our Marcellus properties for $157.9 million along with $34.4 million for additional working interests in our Pouce Coupe waterflood property in Canada. Property divestments in 2013 totaled $365.1 million. In Canada we generated proceeds of $257.5 million from the divestment of non-core assets with production of approximately 2,700 BOE/day. We also sold our undeveloped Montney acreage for proceeds of $131.5 million, of which $65.7 million was recognized in 2013 with the remainder recognized in 2014. In the U.S. we sold facilities in Fort Berthold for proceeds of $35.2 million and entered into fee based processing and gathering contracts.

*2016 Guidance*

As a result of the continued weakness in commodity prices, we are reducing our planned capital spending to $200 million in 2016, approximately 60% below 2015 levels as we defer capital spending across all of our core areas in 2016 to preserve our financial flexibility. Approximately 90% of spending is expected to be directed to our Canadian and U.S. crude oil properties, with the remaining 10% directed to our natural gas assets.

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

| ($ millions, except per BOE amounts) | 2015 | 2014 | 2013 |
|---|---|---|---|
| DD&A expense | $ 507.3 | $ 566.7 | $ 593.2 |
| Per BOE | $ 13.05 | $ 15.06 | $ 18.10 |

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. In 2015, DD&A decreased from 2014 primarily due to the quarterly asset impairments recorded during 2015 under the U.S. GAAP full cost ceiling test methodology. DD&A decreased during 2014 as a result of large reserve additions at December 31, 2013 which lowered our depletion rate.

### Impairments

*PP&E*

| ($ millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Canada cost centre | $ 286.7 | $ – | $ – |
| U.S. cost centre | $ 1,065.7 | $ – | $ – |
| Total Impairments | $ 1,352.4 | $ – | $ – |

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country cost centre basis using estimated after-tax future net cash flows discounted at 10% 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. Standardized Measure is not related to our capital spending 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 have decreased significantly in 2015 resulting in non-cash impairments totaling $1,352.4 million (before tax), with $286.7 million in the Canada cost centre and $1,065.7 million in the U.S. cost centre. We did not record any impairments on our oil and natural gas properties in 2014 or 2013.

The following table outlines the twelve month average trailing benchmark prices and exchange rates used in our ceiling test at December 31, 2015, 2014 and 2013:

| Year | 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 |
|---|---|---|---|---|---|
| 2015 | $ 50.28 | 1.27 | $ 59.38 | $ 2.58 | $ 2.69 |
| 2014 | $ 94.99 | 1.09 | $ 94.84 | $ 4.30 | $ 4.60 |
| 2013 | $ 96.94 | 1.03 | $ 93.19 | $ 3.67 | $ 3.16 |

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. For the next year, 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.

Had we used the 2016 guidance price assumptions to perform our year end full cost ceiling test in lieu of the required historical twelve month trailing benchmark prices, our 2015 impairment (before tax) would have been higher by approximately $110 million in the Canada cost centre and $190 million in the U.S. cost centre.

*Goodwill*

Goodwill impairment testing is performed annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. We perform a qualitative assessment of goodwill by evaluating potential indicators of impairment, and if it is more likely than not that the fair value of the reporting unit is less than its carrying value we perform quantitative impairment tests. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to earnings in the Consolidated Statements of Income/(Loss).

Our annual goodwill impairment assessment as at December 31, 2015 indicated no impairment. However, further weakness in the commodity price environment and our share price may lead to a future impairment of goodwill.

### 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 management's estimate of our net ownership interest, costs to abandon and reclaim and the timing of the costs to be incurred in future periods.

We have estimated the net present value of our asset retirement obligation to be $206.4 million at December 31, 2015 compared to $288.7 million at December 31, 2014. For the year-ended December 31, 2015, the changes include a $35.4 million change in estimate as a result of decreases in estimated future abandonment and reclamation costs in a lower cost environment as well as the removal of $48.7 million of asset retirement obligations related to divestments. See Note 8 to the Financial Statements for further information.

We take an active approach to managing our abandonment, reclamation and remediation obligations. During 2015, we spent $14.9 million (2014 – $19.4 million; 2013 – $16.6 million) on our asset retirement obligations and we expect to spend approximately $11.0 million in 2016. Our abandonment and reclamation costs are expected to be incurred over the next 65 years with the majority between 2026 and 2055. We do not reserve cash or assets for the purpose of funding our future asset retirement obligations. Any abandonment and reclamation costs are anticipated to be funded out of cash flow and available credit facilities.

### Income Taxes

| ($ millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Current tax expense/(recovery) | $ (16.9) | $ 5.0 | $ 7.9 |
| Deferred tax expense/(recovery) | (150.6) | 132.8 | 30.7 |
| Total tax expense/(recovery) | $ (167.5) | $ 137.8 | $ 38.6 |

Our current tax recovery mainly relates to an expected Alternative Tax Net Operating Loss ("ATNOL") in the U.S. which we plan to carry-back to recover Alternative Minimum Tax ("AMT") that was previously paid in 2013 and 2014.

Total tax recovery in 2015 was $167.5 million compared to an expense of $137.8 million in 2014. The recovery in 2015 is due primarily to lower income in 2015 which included $1,352.4 million of non-cash ceiling test impairments offset by a valuation allowance of $443.7 million recorded against a portion of our deferred income tax assets. 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 not be realized. We have considered available positive and negative evidence including future taxable income and reversing existing temporary differences in making this assessment. This assessment is primarily the result of projecting future taxable income using historical trailing twelve month benchmark prices similar to the full cost ceiling test. Had we utilized forecast prices and costs to estimate future taxable income we expect that all of our deferred income tax assets would be realized and no valuation allowance would be required. After recording the valuation allowance, our overall net deferred income tax asset is $516.1 million as at December 31, 2015.

Total tax expense in 2014 was $137.8 million compared to $38.6 million in 2013. The increase in tax is primarily related to higher net income before taxes in 2014, which increased to $436.9 million from $86.6 million in 2013. The majority of the increase in net income came from our Canadian operations and related to non-cash mark-to-market gains on our commodity derivatives which resulted in an increase to our deferred tax expense.

Our estimated tax pools at December 31, 2015 are as follows:

| **Pool Type** ($ millions) | | **2015** |
|---|---|---|
| Canada | | |
| Canadian development expenditures ("CDE") | $ | 213 |
| Canadian exploration expenditures ("CEE") | | 235 |
| Undepreciated capital costs ("UCC") | | 236 |
| Non-capital losses and other credits | | 376 |
| | $ | 1,060 |
| U.S. | | |
| Alternative minimum tax credit ("AMT") | $ | 117 |
| Net operating losses | | 748 |
| Depletable and depreciable assets | | 1,558 |
| | $ | 2,423 |
| Total tax pools and credits | $ | 3,483 |
| Capital losses | $ | 1,171 |

Capital losses reflect the balance of unused capital losses available for carry-forward in Canada. These capital losses have an indefinite carry-forward period however can only be used to offset capital gains. We do not anticipate future capital gains that will allow us to utilize the capital losses. Therefore, a full valuation allowance has been applied to the deferred tax asset in respect of these capital losses.

### 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, which is a senior debt to EBITDA threshold of 3.5x for a period of up to six months, after which it drops to 3.0x. At December 31, 2015, our senior debt to EBITDA ratio was 2.2x and our Debt to Funds Flow Ratio was 2.5x. Although it is not included in our debt covenants, the Debt to Funds Flow Ratio is often used by investors and analysts to evaluate our liquidity.

Despite a decrease in our oil and gas sales revenue due to the ongoing low commodity prices, we have continued to maintain our financial flexibility through an ongoing focus on cost efficiencies, the success of our non-core asset divestment program, disciplined capital spending and a reduction in dividends. We reported net acquisition and divestment proceeds of $277.1 million during 2015, compared to $185.1 million in 2014. We have reduced our monthly dividend to $0.01 per share, effective with our April payment, and expect to save approximately $95 million in 2016 compared to 2015 dividend levels. Our Adjusted Payout Ratio, which is calculated as cash dividends plus capital and office expenditures divided by Funds Flow, was 128% in 2015, compared to 118% in 2014. After adjusting for net acquisition and divestment proceeds, our Adjusted Payout Ratios for 2015 and 2014 decrease to 72% and 97%, respectively.

Subsequent to year end, we entered into two agreements to sell additional Canadian Deep Basin natural gas assets for proceeds of approximately $193.0 million. In January, we received proceeds of $183.0 million upon closing one transaction and we expect the second transaction to close during the first quarter of 2016. We used the proceeds to repay our outstanding bank debt and a portion of our outstanding senior notes to further improve our liquidity going into 2016. We expect the remaining proceeds to be directed towards our 2016 capital spending program. As a result of the divestments, we expect to record a gain of approximately $145 million during the first quarter of 2016, which will improve our EBITDA in 2016.

Our working capital deficiency, excluding cash and current deferred financial and tax balances, decreased to $104.0 million at December 31, 2015 from $260.5 million at December 31, 2014. We expect to finance our working capital deficit and our ongoing working capital requirements through Funds Flow and our bank credit facility. In addition, we have sufficient liquidity to meet our financial commitments for the near term, as disclosed under "Commitments" below.

Total debt, net of cash, at December 31, 2015 was $1,216.2 million compared to $1,134.9 million at December 31, 2014. Total debt was comprised of $86.5 million of bank indebtedness and $1,137.1 million of senior notes less $7.5 million in cash. At December 31, 2015, we were approximately 11% drawn on our $800 million bank credit facility. The increase in our reported debt balance was due to the impact of a weakening Canadian dollar on our U.S. dollar denominated senior notes. During 2015, we repaid US$50.8 million and CDN$40 million on the final maturities of our US$54 million, US$40 million and CDN$40 million senior notes. We have no additional scheduled debt repayments until June of 2017, with remaining maturities extending to 2026. As a result of the first quarter divestment proceeds along with our lowered capital spending and dividends, we expect to further reduce our debt levels during 2016.

During the fourth quarter, we completed a one year extension of our senior, unsecured, covenant-based bank credit facility which now matures on October 31, 2018. As part of the extension, we reduced our bank credit facility to $800 million from $1 billion and increased our maximum Total Debt to Capitalization ratio to 55% from 50%. Our decision to decrease the facility balanced the need for sufficient liquidity to execute our business plan with the associated costs of maintaining a largely undrawn bank facility. We expect the renewed facility amount to provide more than sufficient liquidity to complete our 2016 capital spending plan and anticipate savings of approximately $1 million as a result of the decreased facility size. Drawn and undrawn fees on our bank credit facility range between 150 and 315 basis points over Bankers' Acceptance rates, with current drawn fees of 205 basis points. The bank credit facility ranks equally with our unsecured, covenant-based senior notes.

At December 31, 2015 we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Based on our guidance price assumptions, we do not expect to exceed our Debt to EBITDA ratio during 2016. However, if the current commodity price levels persist, we would expect to begin negotiating covenant amendments with our lenders towards the end of 2016. If we exceed any of the covenants, we may be required to repay, refinance or renegotiate the terms of the debt. If we reach or exceed these covenant thresholds, there are a number of steps that may be taken to improve them, including asset divestments, a reduction to capital spending and equity issuances.

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 December 31, 2015:

| Covenant Description | | December 31, 2015 |
|---|---|---|
| **Bank Credit Facility:** | **Maximum Ratio** | |
| Senior Debt to EBITDA | 3.5x | 2.2x |
| Total Debt to EBITDA | 4.0x | 2.2x |
| Total Debt to Capitalization | 55% | 38% |
| **Senior Notes:** | **Maximum Ratio** | |
| Senior Debt to EBITDA(1) | 3.0x – 3.5x | 2.2x |
| Maximum debt to consolidated present value of total proved reserves(2) | 60% | 54% |
| | **Minimum Ratio** | |
| EBITDA to Interest | 4.0x | 8.6x |

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.

"EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, accretion and non-cash gains and losses. EBITDA is calculated on a trailing twelve month basis and is adjusted for material acquisitions and divestments. EBITDA for the three months and the trailing twelve months ended December 31, 2015 were $118.8 million and $573.0 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) Senior Debt to EBITDA maximum ratio for the senior notes may increase to 3.5x for a period of 6 months, after which the ratio decreases to 3.0x.

(2) Maximum 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%.

### Counterparty Credit

#### OIL AND NATURAL GAS SALES COUNTERPARTIES

Our oil and natural gas receivables are with customers in the oil and gas industry and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. To date, we have not experienced any losses. A credit review process is in place to assess and monitor our counterparties' creditworthiness on a regular basis. This process involves reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted, we obtain financial assurances such as letters of credit, parental guarantees or third party insurance to mitigate a portion of our credit risk. This process is utilized for both our oil and natural gas sales counterparties as well as our financial derivative counterparties.

#### FINANCIAL DERIVATIVE COUNTERPARTIES

We are exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. We mitigate this risk by entering into transactions with major financial institutions, the majority of which are members of our bank syndicate. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the great majority of our financial counterparties. These agreements provide some credit protection by generally allowing parties to aggregate amounts owing to each other under all outstanding transactions and settle with a single net amount in the case of a credit event. To date we have not experienced any losses due to non-performance by our derivative counterparties. At December 31, 2015 we had $71.4 million in mark-to-market assets offset by $7.3 million of mark-to-market liabilities resulting in a net asset position of $64.1 million. The majority of our outstanding derivative contracts are with financial institutions which are members of our bank syndicate. All of our derivative counterparties are considered investment grade.

### Dividends

| ($ millions, except per share amounts) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Cash dividends | $ 132.0 | $ 199.3 | $ 170.7 |
| Stock dividend plan | – | 21.8 | 46.2 |
| Total dividends to shareholders | $ 132.0 | $ 221.1 | $ 216.9 |
| Per weighted average share (Basic) | $ 0.64 | $ 1.08 | $ 1.08 |

We reported total dividends of $132.0 million or $0.64 per share to our shareholders in 2015. During 2014 and 2013 we reported total dividends of $221.1 million or $1.08 per share and $216.9 million or $1.08 per share, respectively.

Cash dividends for 2015 represented approximately 27% of Funds Flow compared to approximately 23% for 2014 and 2013. In September 2014 we elected to suspend our stock dividend plan, thereby eliminating any dilution resulting from issuing shares as part of our dividend plan.

To provide additional financial flexibility and to better balance Funds Flow with capital and dividends, we are reducing our monthly dividend to $0.01 per share, effective with our April payment. We reduced our monthly dividend twice during 2015, from $0.09 per share to $0.05 per share in April, followed by a reduction to $0.03 per share in December. Compared to total 2015 dividends paid, we expect to save approximately $95 million in 2016 as a result of the overall reduction to $0.01 per share. The dividend is an important part of our strategy to create shareholder value; however, a sustained low price environment may impact our ability to pay dividends. We will continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

### Shareholders' Capital

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| Share capital ($ millions) | $ 3,133.5 | $ 3,120.0 | $ 3,061.8 |
| Common shares outstanding (thousands) | 206,539 | 205,732 | 202,758 |
| Weighted average shares outstanding – basic (thousands) | 206,205 | 204,510 | 200,567 |
| Weighted average shares outstanding – diluted (thousands) | 206,205 | 207,424 | 201,404 |

During 2015, a total of 807,000 shares (2014 – 2,974,000; 2013 – 4,074,000) and $13.3 million of additional equity (2014 – $53.2 million; 2013 – $61.0 million) was issued pursuant to the stock option plan, the treasury-settled LTI plans and treasury-settled terminations. For further details see Note 14 to the Financial Statements.

At February 18, 2016 we had 206,539,459 shares outstanding.

### Commitments

As at December 31, 2015 we had the following minimum annual commitments:

| ($ millions) | Total | 2016 | 2017 | 2018 | 2019 | 2020 | Total Committed after 2020 |
|---|---|---|---|---|---|---|---|
| | | Minimum Annual Commitment Each Year | | | | | |
| Bank credit facility | $ 86.5 | $ – | $ – | $ 86.5 | $ – | $ – | $ – |
| Senior notes[1] | 1,137.1 | – | 62.3 | 62.3 | 92.2 | 160.5 | 759.8 |
| Transportation commitments | 189.6 | 39.5 | 30.3 | 16.0 | 14.2 | 13.1 | 76.5 |
| Processing commitments | 58.0 | 12.4 | 12.0 | 10.6 | 10.5 | 1.7 | 10.8 |
| Drilling and completions | 8.5 | 6.6 | 1.9 | – | – | – | – |
| Office leases | 103.2 | 11.6 | 11.8 | 11.7 | 10.3 | 10.8 | 47.0 |
| Total commitments[2][3] | $ 1,582.9 | $ 70.1 | $ 118.3 | $ 187.1 | $ 127.2 | $ 186.1 | $ 894.1 |

(1) Interest payments have not been included. Subsequent to December 31, 2015, we repaid US$57 million of our senior notes.

(2) US$ commitments have been converted to CDN$ using the December 31, 2015 foreign exchange rate of 1.3840 US/CDN.

(3) Crown and surface royalties, production taxes, lease rentals, and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.

We have various firm sales and transportation contracts in place for an average of 13,000 bbls/day of our U.S. oil production through 2016. In addition, we have contracted firm capacity of 5,000 bbls/day for five years on the Enbridge Sandpiper crude oil pipeline project with an expected in-service date of 2019, pending regulatory approvals. In Canada, we have various firm transportation agreements for approximately 500 BOE/day of our crude oil and liquids production in 2016, increasing to an average of approximately 900 BOE/day from 2017 to 2027.

We have firm sales contracts for up to 65,000 Mcf/day in our Marcellus producing region through 2026. We also have firm transportation agreements in place for approximately 36,000 Mcf/day which expire between 2020 and 2033. We have also entered into a binding contract for five years of firm transportation capacity for 30,000 Mcf/day on the PennEast pipeline project. This project is currently pending regulatory approval with an expected in-service date of 2018.

Our Canadian office lease is committed to 2024 and our U.S. office lease expires in 2019. Annual costs of these lease commitments include rent and operating fees. Our commitments, contingencies and guarantees are more fully described in Note 16 to the Financial Statements.

Subsequent to December 31, 2015, we entered into a binding contract for interstate pipeline capacity on the Tennessee Gas Pipeline from our Marcellus producing region to downstream connections. Effective August 1, 2016, we are committed to a US$0.63/Mcf demand toll for 30,000 Mcf/day of natural gas for 11 years, reducing to 15,000 Mcf/day for an additional 9 years, with a total estimated transportation commitment of $148.3 million extending to 2036.

## SELECTED ANNUAL CANADIAN AND U.S. FINANCIAL RESULTS

| | Year ended December 31, 2015 | | | Year ended December 31, 2014 | | |
|---|---|---|---|---|---|---|
| (millions, except per unit amounts) | Canada | U.S. | Total | Canada | U.S. | Total |
| **Average Daily Production Volumes[1]** | | | | | | |
| Crude oil (bbls/day) | 15,165 | 26,474 | 41,639 | 16,667 | 23,541 | 40,208 |
| Natural gas liquids (bbls/day) | 1,997 | 2,766 | 4,763 | 2,477 | 1,088 | 3,565 |
| Natural gas (Mcf/day) | 136,924 | 223,809 | 360,733 | 150,930 | 205,212 | 356,142 |
| Total average daily production (BOE/day) | 39,983 | 66,541 | 106,524 | 44,299 | 58,831 | 103,130 |
| **Pricing[2]** | | | | | | |
| Crude oil (per bbl) | $ 45.28 | $ 50.23 | $ 48.43 | $ 83.53 | $ 88.22 | $ 86.28 |
| Natural gas liquids (per bbl) | 29.41 | 9.88 | 18.06 | 55.55 | 43.01 | 51.72 |
| Natural gas (per Mcf) | 2.83 | 1.74 | 2.15 | 4.49 | 3.54 | 3.94 |
| **Capital Expenditures** | | | | | | |
| Capital spending | $ 157.7 | $ 335.7 | $ 493.4 | $ 308.3 | $ 502.7 | $ 811.0 |
| Acquisitions | 3.6 | 5.9 | 9.5 | 2.0 | 16.5 | 18.5 |
| Divestments | (198.9) | (87.7) | (286.6) | (154.6) | (49.0) | (203.6) |
| **Netback[3] Before Hedging** | | | | | | |
| Oil and natural gas sales | $ 414.4 | $ 638.0 | $ 1,052.4 | $ 807.9 | $ 1,041.4 | $ 1,849.3 |
| Royalties | (44.8) | (123.2) | (168.0) | (118.8) | (204.3) | (323.1) |
| Production taxes | (5.5) | (45.4) | (50.9) | (9.2) | (72.3) | (81.5) |
| Cash operating expenses | (216.7) | (123.4) | (340.1) | (252.9) | (94.4) | (347.3) |
| Transportation costs | (22.6) | (92.1) | (114.7) | (24.6) | (76.6) | (101.2) |
| Netback before hedging | $ 124.8 | $ 253.9 | $ 378.7 | $ 402.4 | $ 593.8 | $ 996.2 |
| **Other Expenses** | | | | | | |
| Commodity derivative instruments loss/(gain) | $ (142.7) | $ – | $ (142.7) | $ (234.4) | $ – | $ (234.4) |
| General and administrative expense[4] | 77.0 | 26.9 | 103.9 | 79.1 | 25.9 | 105.0 |
| Current income tax expense/(recovery) | (0.8) | (16.1) | (16.9) | (0.5) | 5.5 | 5.0 |

(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.

## THREE YEAR SUMMARY OF KEY MEASURES

| ($ millions, except per share amounts) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Oil and natural gas sales, net of royalties | $ 884.4 | $ 1,526.2 | $ 1,352.5 |
| Net income/(loss) | (1,523.4) | 299.1 | 48.0 |
| Per share (Basic) | (7.39) | 1.46 | 0.24 |
| Per share (Diluted) | (7.39) | 1.44 | 0.24 |
| Funds Flow | 493.1 | 859.0 | 754.2 |
| Cash and stock dividends[1] | 132.0 | 221.1 | 216.9 |
| Per share (Basic)[1] | 0.64 | 1.08 | 1.08 |
| Total assets | 2,581.2 | 4,031.5 | 3,681.8 |
| Long-term debt, net of cash[2] | 1,216.2 | 1,134.9 | 1,022.3 |

(1) Calculated based on dividends paid or payable. Cash and stock dividends to shareholders per share may not correspond to actual dividends as a result of using the annual weighted average shares outstanding.
(2) Including current portion of long-term debt.

Oil and natural gas sales, net income and Funds Flow decreased during 2015 due to the sustained weakness in commodity prices, which was somewhat offset by production growth. Funds Flow benefited from realized cash gains on our commodity hedges, which increased to

$287.7 million in 2015 compared to $3.5 million in 2014. A net loss was realized in 2015 primarily as a result of non-cash asset impairment charges of $1,352.4 million and a non-cash valuation allowance on our deferred income tax asset of $443.7 million, along with lower oil and natural gas sales revenue and a $91.7 million decrease in total gains on commodity hedges.

Oil and natural gas sales, net income and Funds Flow increased during 2014 due to increased production volumes and higher overall realized prices. Net income also increased as a result of cash and non-cash hedging gains, which totaled $234.4 million in 2014, compared to losses of $41.9 million in 2013.

## QUARTERLY FINANCIAL INFORMATION

| ($ millions, except per share amounts) | Oil and Natural Gas Sales, Net of Royalties | Net Income/(Loss) | Net Income/(Loss) Per Share Basic | Net Income/(Loss) Per Share Diluted |
|---|---|---|---|---|
| **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) |
| **2014** | | | | |
| Fourth Quarter | $ 325.3 | $ 151.7 | $ 0.74 | $ 0.73 |
| Third Quarter | 378.3 | 67.4 | 0.33 | 0.32 |
| Second Quarter | 414.9 | 40.0 | 0.20 | 0.19 |
| First Quarter | 407.7 | 40.0 | 0.20 | 0.19 |
| Total 2014 | $ 1,526.2 | $ 299.1 | $ 1.46 | $ 1.44 |

Oil and natural gas sales, net of royalties, generally increased until the third quarter of 2014 when realized commodity prices began to steadily decline.

Net losses reported in 2015 are primarily due to asset impairments related to the decrease in the trailing twelve month average commodity prices, along with reduced oil and natural gas sales revenue. We did not record any asset impairments in 2014. Net income increased in the fourth quarter of 2014 as a result of significant non-cash commodity hedging gains offsetting the decrease in oil and natural gas sales.

## ENVIRONMENT

We strive to carry out our activities and operations in compliance with all applicable regulations and best industry practices. Our operations are subject to laws and regulations concerning pollution, protection of the environment and the handling of hazardous materials and waste. We set corporate targets and mandates to improve environmental performance and execute environmental initiatives to become more energy efficient and to reduce, reuse and recycle water and minimize waste.

Our Safety and Social Responsibility ("S&SR") Committee of our Board of Directors' is responsible for review of the S&SR Policy, performance and continuous improvement of the S&SR management system to ensure that our activities are planned and executed in a safe and responsible manner and to ensure that we have adequate systems to support ongoing compliance. We may be subject to environmental and other costs resulting from unknown and unforeseeable environmental impacts arising from our operations and extreme weather events. There are inherent risks of spills and pipeline leaks at our operating sites and clean-up costs may be significant. However, we have active site inspection, corrosion risk management and asset integrity management programs to help minimize this risk. In addition, we carry environmental insurance to help mitigate the cost of releases should they occur.

We intend to continue to improve energy efficiencies and proactively manage our greenhouse gas emissions in compliance with applicable government regulations.

We use the hydraulic fracturing process in our operations. Government and regulatory agencies continue to frame regulations related to this process. We believe we are in compliance with all current government regulations and industry best practices in the U.S. and Canada. Although we proactively mitigate perceived risks involved in the hydraulic fracturing process, increased capital and operating costs may be incurred if regulations in Canada or the United States impose more stringent compliance requirements surrounding hydraulic fracturing.

## CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with U.S. GAAP requires management to make certain judgments and estimates. Due to the timing of when activities occur compared to the reporting of those activities, management must estimate and accrue operating results and capital spending. Changes in these judgments and estimates could have a material impact on our financial results and financial condition.

### Reserves

The process of estimating reserves is critical to several accounting estimates. It requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and natural gas prices, operating costs and royalty burdens change. Reserves estimates impact net income through depletion, the determination of asset retirement obligation and the application of impairment tests. Revisions or changes in reserves estimates can have either a positive or a negative impact on net income.

### Asset Impairment

*Ceiling Test*

Under the full cost method of accounting for Property, Plant and Equipment, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and natural gas properties exceed the cost centre ceiling, we are subject to a ceiling test write-down to the extent of such excess. These write-downs reduce net income and impact shareholders' equity in the period of occurrence and result in lower depletion expense in future periods. The volume and discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and natural gas that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average oil and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that further write-downs of our oil and natural gas properties could occur in the future. Under U.S. GAAP impairments are not reversed in future periods.

*Goodwill*

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment at least annually at December 31. Goodwill and all other assets and liabilities are allocated to reporting units. To assess impairment, the carrying amount of each reporting unit is determined and compared to the fair value of the reporting unit. If the carrying amount of the reporting unit is higher than its related fair value then goodwill is written down to the reporting unit's implied fair value of goodwill. The fair value used in the impairment test is based on estimates of discounted future cash flows which involve assumptions of natural gas and liquids reserves, including commodity prices, future costs and discount rates.

### Income Taxes

Management makes certain estimates in calculating deferred tax assets and liabilities, as well as income tax expense. These estimates often involve judgment regarding differences in the timing and recognition of revenue and expense for tax and financial reporting purposes as well as the tax basis of our assets and liabilities at the balance sheet date before tax returns are completed. Additionally, we must assess the likelihood we will be able to recover or utilize our deferred tax assets. We must record a valuation allowance against a deferred tax asset where all or a portion of that asset is not expected to be realized. In evaluating whether a valuation allowance should be applied, we consider evidence such as future taxable income, among other factors, both positive and negative. That determination involves numerous judgments and assumptions and includes estimating factors such as commodity prices, production and other operating conditions. If any of those factors, assumptions or judgements changes, the deferred tax asset could change, and in particular decrease in a period where we determine it is more likely than not that the asset will not be realized.

### Asset Retirement Obligation

Management calculates the asset retirement obligation based on estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. The fair value estimate is capitalized to PP&E as part of the cost of the related asset and depleted over its useful life. There are uncertainties related to asset retirement obligations and the impact on the financial statements could be material as the eventual timing and costs for the obligations could differ from our estimates. Factors that could cause our estimates to differ include any changes to laws or regulations, reserves estimates, costs and technology.

### Business Combinations

Management makes various assumptions in determining the fair value of any acquired company's assets and liabilities in a business combination. The most significant assumptions and judgments made relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we, and independent evaluators, estimate oil and gas reserves and future prices of crude oil and natural gas.

### Derivative Financial Instruments

We utilize derivative financial instruments to manage our exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Fair values of derivative contracts fluctuate depending on the underlying estimate of future commodity prices, foreign currency exchange rates, interest rates and counterparty credit risk.

## RECENT U.S. GAAP ACCOUNTING AND RELATED PRONOUNCEMENTS

Refer to Note 2(n) in our Financial Statements for a detailed listing of Standards and Interpretations that were issued but not yet effective at December 31, 2015.

## RISK FACTORS AND RISK MANAGEMENT

### Commodity Price Risk

Our operating results and financial condition are dependent on the prices we receive for our crude oil, natural gas liquids, and natural gas production. These prices have fluctuated widely in response to a variety of factors including global and domestic supply and demand of crude oil, natural gas and NGLs, weather conditions, the price of imported oil and liquefied natural gas, the production and storage levels of North American natural gas, natural gas liquids and crude oil, political stability, transportation facilities, availability of processing, fractionation and refining facilities, the price and availability of alternative fuels and government regulations.

Any further decline in crude oil or natural gas prices may have a material adverse effect on our operations, financial condition, borrowing ability, levels of reserves and resources and the level of expenditures for the development of our oil and natural gas reserves or resources. Certain oil or natural gas wells may become or remain uneconomic to produce if commodity prices are low, thereby impacting our production volumes, or our desire to market our production in unsatisfactory market conditions. Furthermore, we may be subject to the decisions of third party operators who, independently and using different economic parameters, may decide to curtail production.

*We may use financial derivative instruments and other hedging mechanisms to help limit the adverse effects of natural gas and crude oil price volatility. However, we do not hedge all of our production and expect there will always be a portion that remains unhedged. Historically, we have seldom hedged prices more than 24 months in advance. Furthermore, we may use financial derivative instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, we may forego the benefits that would otherwise be experienced if commodity prices increase. At February 3, 2016, approximately 36% of our 2016 forecasted net crude oil production is hedged and approximately 28% of our forecasted net natural gas production is hedged at price levels disclosed in the "Price Risk Management" section above. To date, we have no hedges on our forecasted production for 2017, exposing substantially all of our earnings to commodity price volatility. Refer to the "Price Risk Management" section for further details on our price risk management program.*

### Debt covenants may be exceeded with no ability to negotiate covenant relief

Further declines in oil and natural gas prices or continued weakness in prices may result in a significant reduction in earnings or cash flow, which could lead us to increase drawn amounts under the bank credit facility in order to carry out our operations and fulfill our obligations. Significant reductions to cash flow, significant increases in drawn amounts under the bank credit facility or significant reductions to proved reserves may result in a breach of our debt covenants. If a breach occurs, there is a risk that we may not be able to negotiate covenant relief with one or more of our lenders. Failure to comply with debt covenants or negotiate relief may result in our indebtedness under the bank credit facility and senior note agreements becoming immediately due and payable, which may have a material adverse effect on our operations and financial condition.

### Risk of Curtailments in Production

Should we be required to curtail or shut-in production as a result of low commodity prices, environmental regulation or third party operational practices, it could result in a reduction to cash flow and production levels, among other things. In addition, curtailments or shut-ins may cause damage to the reservoir that may prevent us from achieving production and operating levels that were in place prior to the curtailment or shutting-in of the reservoir and may result in additional operating and capital costs for the well to achieve prior production levels.

### Risk of Impairment of Oil and Gas Assets

Under U.S. GAAP, the net capitalized cost of oil and gas properties, net of deferred income taxes, is limited to the present value of after-tax future net revenue from proved reserves, discounted at 10%, and based on the unweighted average of the closing prices for the applicable commodity on the first day of the twelve months preceding the issuer's fiscal year-end. The amount by which the net capitalized costs exceed the discounted value will be charged to net income. While these write-downs would not affect cash flow, the charge to earnings may be viewed unfavourably in the market. Based on the use of the twelve month average trailing benchmark prices, there is an increased risk of further impairment on our oil and gas properties if commodity prices fail to recover during 2016. Any additional write-downs may lead to a breach of our Total Debt to Capitalization covenant under the bank credit facility, and we may not be able to renegotiate our covenants.

### Oil and Gas Reserves and Resources Risk

The value of our company is based on, among other things, the underlying value of our oil and gas reserves and resources. Geological and operational risks along with product price forecasts can affect the quantity and quality of reserves and resources and the cost of ultimately recovering those reserves and resources. Lower crude oil, natural gas liquids, and natural gas prices along with lower development capital spending associated with certain projects may increase the risk of write-downs for our oil and gas property investments. Changes in reporting methodology as well as regulatory practices can result in reserves or resources write-downs.

*Each year, independent reserves engineers evaluate the majority of our proved and probable reserves as well as evaluating or auditing the resources attributable to a significant portion of our undeveloped land. All reserves information, including our U.S. reserves, has been prepared in accordance with NI 51-101 standards. For U.S. GAAP accounting purposes our proved reserves are estimated to be technically the same as our proved reserves prepared under NI 51-101 and have been adjusted for the effects of SEC constant prices. Independent reserves evaluations have been conducted on approximately 84% of the total proved plus probable net present value (discounted at 10%) of our reserves at December 31, 2015. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 45% of our Canadian reserves and reviewed the internal evaluation completed by Enerplus on the remaining portion. McDaniel also evaluated 100% of the reserves associated with our U.S. tight oil assets. Netherland, Sewell & Associates, Inc. (NSAI) evaluated 100% of our U.S. Marcellus shale gas assets.*

*The evaluations of contingent resources associated with our Wilrich and Fort Berthold assets were conducted by Enerplus and audited by McDaniel. NSAI evaluated our Marcellus shale gas contingent resources. The contingent resource assessments associated with a portion of our waterflood properties were completed internally by Enerplus' qualified reserves evaluators.*

*The Reserves Committee and the Board of Directors has reviewed and approved the reserves and resources reports of the independent evaluators.*

### Access to Capital Markets

Our access to capital has allowed us to fund a portion of our acquisitions and development capital program through issuance of equity and debt in past years. Continued access to capital is dependent on our ability to optimize our existing assets and to demonstrate the advantages of the acquisition or development program that we are financing at the time as well as investors' view of the oil and gas industry overall. We may not be able to access the capital markets in the future on terms favorable to us, or at all. Our continued access to capital markets is dependent on corporate performance and investor perception of future performance (both corporately and for the oil and gas sector in general).

We are required to assess our "foreign private issuer" status under U.S. securities laws on an annual basis. If we were to lose our status as a "foreign private issuer" under U.S. securities laws, we may have restricted access to capital markets for a period of time until the required approvals are in place from the U.S. Securities and Exchange Commission.

### Access to Transportation and Processing Capacity

Market access for crude oil, NGLs and natural gas production in Canada and the United States is dependent on our ability to obtain transportation capacity on third party pipelines and rail as well as access to processing facilities. Newer resource plays, such as the North Dakota Bakken and the Marcellus shale gas, generally experience a sharp production increase in the area which could exceed the existing capacity of the gathering, pipeline, processing or rail infrastructure. While third party pipelines, processors and independent rail operators generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of capacity. There are occasionally operational reasons for curtailing transportation and processing capacity. Accordingly, there can be periods where transportation and processing capacity is insufficient to accommodate all of the production from a given region, causing added expense and/or volume curtailments for all shippers. Our assets are concentrated in specific regions with varying levels of government that could limit or ban the shipping of commodities by truck, pipeline or rail. Additionally, the transportation of crude oil by rail may come under closer scrutiny by government regulatory agencies in Canada and the United States. As a result, there may be incremental costs associated with transporting crude oil by rail, and there is a risk that access to rail transport may be constrained, depending upon any changes made to existing rail transport regulations.

*We continuously monitor this risk for both the short and longer term through dialogue and review with the third party pipelines and other market participants. Where available and commercially appropriate, given the production profile and commodity, we attempt to mitigate transportation and processing risk by contracting for firm pipeline or processing capacity or using other means of transportation, including rail and truck. We maintain a diverse mix of pipeline, rail and trucking transportation options within our portfolio.*

### Access to Field Services

Our ability to drill, complete and tie-in wells in a timely manner may be impacted by our access to service providers and supplies. Activity levels in a given area may limit our access to these resources, restricting our ability to execute our capital plans in a timely manner. In addition, field service costs are influenced by market conditions and therefore can become cost prohibitive.

*Although we have entered into service contracts for a portion of field services that will secure some of our drilling and fracturing services into 2016, access to field services and supplies in other areas of our business will continue to be subject to market availability.*

### Title Defects or Litigation

Unforeseen title defects or litigation may result in a loss of entitlement to production, reserves and resources.

*Although we conduct title reviews prior to the purchase of assets these reviews do not guarantee that an unforeseen defect in the chain of title will not arise. We maintain good working relationships with our industry partners; however disputes may arise from time to time with respect to ownership of rights of certain properties or resources.*

### Regulatory Risk & Greenhouse Gas Emissions

Government royalties, environmental laws and regulatory requirements can have a significant financial and operational impact on us. As an oil and gas producer, we operate under federal, provincial, state and municipal legislation and regulation that govern such matters as royalties, land tenure, prices, production rates, various environmental protection controls, well and facility design and operation, income, and the exportation of crude oil, natural gas and other products. We may be required to apply for regulatory approvals in the ordinary course of business. To the extent that we fail to comply with applicable government regulations or regulatory approvals, we may be subject to fines, enforcement proceedings and the restriction or complete revocation of rights to conduct our business.

Government regulations may be changed from time to time in response to economic or political conditions. Additionally, our entry into new jurisdictions or adoption of new technology may attract additional regulatory oversight which could result in higher costs or require changes to proposed operations. Canadian and U.S. governments have enhanced their oversight and reporting obligations associated with fracturing procedures and increased their scrutiny of the usage and disposal of chemicals and water used in fracturing procedures. Additionally, various levels of Canadian and U.S. governments are considering or have implemented legislation to reduce emissions of greenhouse gases, including volatile organic compounds (“VOC”), and methane gas emissions. Specifically, the Province of Alberta has instituted the Climate Change and Emissions Management Act, which, starting in 2023, sets a carbon tax of $30 per tonne of carbon dioxide equivalent emissions that occur from our Alberta operations. The Province of Alberta has also established a 45% reduction goal for methane gas emissions for our Alberta operations by 2025. The Act will likely increase electrical use costs for our Alberta operations as a carbon tax for electrical use comes into effect in 2017.

The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations could negatively impact the development of oil and gas properties and assets, reduce demand for crude oil and natural gas or impose increased costs on oil and gas companies including taxes, fees or other penalties.

*Although we have no control over these regulatory risks, we continuously monitor changes in these areas by participating in industry organizations, conferences, exchanging information with third party experts and employing qualified individuals to assess the impact of such changes on our financial and operating results.*

*Specifically with respect to regulations for the reduction of greenhouse gas emissions, the Canadian federal government continues to seek alignment for the regulations to be issued in Canada with those of the United States. Accordingly, while we continue to prepare to meet the potential requirements, the actual cost impact and its materiality to our business remains uncertain on a federal level.*

### Health, Safety and Environmental Risk

Health, safety and environmental risks impact our workforce and operating costs and result in the enhancement of our business practices and standards. Certain government and regulatory agencies in Canada and the United States have begun investigating the potential risks associated with hydraulic fracturing including the risk of induced seismicity with the injection of fluid into any reservoir. We expect regulatory frameworks will be amended or continue to emerge in this regard. Although Enerplus proactively mitigates perceived risks involved in the hydraulic fracturing process, increased capital and operating costs may be incurred if regulations in Canada or the United States impose more stringent compliance requirements surrounding hydraulic fracturing. The impact of such changes on our business could increase our cost of compliance and the risk of litigation and environmental liability.

*Enerplus has an S&SR department that develops standards and systems to manage health, safety and environmental risks, and regulatory compliance for the organization. The actions of the S&SR Department are driven in part by a steering committee which is comprised of executives and senior management. All S&SR risks are reviewed regularly by the S&SR committee which is comprised of members of the Board of Directors. We have insurance to cover a portion of its property losses, liability and business interruption. At present, we believe we are, and expect to continue to be, in compliance with all material applicable environmental laws and regulations and have included appropriate amounts in our capital expenditure budget to continue to meet our ongoing environmental obligations.*

### Production Replacement Risk

Oil and natural gas reserves naturally deplete as they are produced over time. Our ability to replace production depends on our success in acquiring new land, reserves and/or resources and developing existing reserves and resources. Acquisitions of oil and gas assets will depend on our assessment of value at the time of acquisition and ability to secure the acquisitions generally through a competitive bid process.

*Acquisitions and our development capital program are subject to investment guidelines, due diligence and review. Major acquisitions and our annual capital development budget are approved by the Board of Directors and where appropriate, independent reserve engineer evaluations are obtained.*

### Counterparty and Joint Venture Credit Exposure

We are subject to the risk that the counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations as a result of liquidity requirements or insolvency. Low oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure of our counterparties to perform their financial or operational obligations may adversely affect our operations and financial position.

*A credit review process is in place to assess and monitor our counterparties' credit worthiness on a regular basis. This includes reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted we attempt to obtain financial assurances such as letters of credit, parental guarantees, or third party insurance to mitigate our counterparty risk. In addition, we monitor our receivables against a watch list of publicly traded companies that have high debt-to-cash flow ratios or fully drawn* *bank facilities and, where possible, take our production in kind rather than relying on third party operators. In certain instances we may be able to aggregate all amounts owing to each other and settle with a single net amount.*

*See the "Liquidity and Capital Resources" section for further information.*

### Foreign Currency Exposure

We have exposure to fluctuations in foreign currency as most of our senior notes are denominated in U.S. dollars. Our U.S. operations are directly exposed to fluctuations in the U.S. dollar when translated to our Canadian dollar denominated financial statements. We also have indirect exposure to fluctuations in foreign currency as our crude oil sales and a portion of our natural gas sales are based on U.S. dollar indices. Our oil and gas revenues are positively impacted when the Canadian dollar weakens relative to the U.S. dollar. However our U.S. capital spending, transportation and operating costs, interest expense and debt repayments are negatively impacted with a weak Canadian dollar.

*Currently, we do not have any foreign exchange contracts in place to hedge our foreign exchange exposure. However, we continue to monitor fluctuations in foreign exchange and the impact on our operations.*

### Interest Rate Exposure

We have exposure to movements in interest rates and credit markets as changing interest rates affect our borrowing costs and value of investments such as our shares as well as other equity investments.

*We monitor the interest rate forward market and have fixed the interest rate on approximately 93% of our debt through our senior notes.*

### Changes in Income Tax and Other Laws

Income tax, other laws or government incentive programs relating to the oil and gas industry may be changed in a manner that adversely affects us or our security holders. Canadian, U.S. and foreign tax authorities may interpret applicable tax laws, tax treaties or administrative positions differently than we do or may disagree with how we calculate our income for tax purposes in a manner which is detrimental to us and our security holders.

*We monitor developments with respect to pending legal changes and work with the industry and professional groups to ensure that our concerns with any changes are made known to various government agencies. We obtain confirmation from independent legal counsel and advisors with respect to the interpretation and reporting of material transactions.*

### Funds Flow Sensitivity

The sensitivities below reflect all commodity contracts listed in Note 15 to the Financial Statements and are based on forward markets as at February 3, 2016. To the extent crude oil and natural gas prices change significantly from current levels, the sensitivities will no longer be relevant.

| **Sensitivity Table** | **Estimated Effect on 2016 Funds Flow per Share[(1)]** |
|---|---|
| Change of $0.50 per Mcf in the price of NYMEX natural gas | $ 0.20 |
| Change of US$5.00 per barrel in the price of WTI crude oil | $ 0.35 |
| Change of 1,000 BOE/day in production | $ 0.01 |
| Change of $0.01 in the US/CDN exchange rate | $ 0.01 |
| Change of 1% in interest rate | $ 0.00 |

(1) Assumes 206.5 million weighted average shares outstanding.

## 2016 GUIDANCE

A summary of our 2016 guidance is below. This guidance includes the impact of the fourth quarter North Dakota and Canadian shallow gas sales, as well as the previously announced sale of Canadian Deep Basin natural gas properties subsequent to year end. No additional potential acquisitions or divestments have been included. This guidance is based on a WTI crude oil price of US$38.63/bbl, NYMEX natural gas price of US$2.43/Mcf, AECO natural gas price of $2.27/GJ and a US/CDN exchange rate of 1.40.

| Summary of 2016 Expectations | Target |
|---|---|
| Capital spending | $200 million |
| Average annual production | 90,000 – 94,000 BOE/day |
| Crude oil and natural gas liquids volumes | 43,000 – 45,000 bbls/day |
| Average royalty and production tax rate (% of gross sales, before transportation) | 23% |
| Operating expenses | $9.50/BOE |
| Transportation costs | $3.30/BOE |
| Cash G&A expenses | $2.10/BOE |

## INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal controls 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 Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at December 31, 2015, 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 October 1, 2015 and ended December 31, 2015 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, 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 forward-looking statements within the meaning of applicable securities laws ("**forward-looking information**"). The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "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 2016 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 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 2016 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 and non-cash G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2016 and its impact on our production level and land holdings; potential future asset and goodwill impairments, as well as the 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 debt-to-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, expectations and assumptions 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 funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our 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 2016 guidance contained in this MD&A is based on the following: a WTI price of $38.63/bbl, a NYMEX price of US$2.43/Mcf, an AECO price of $2.27/GJ and a US/CDN exchange rate of 1.40. We believe 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 and contingencies described under "Risk Factors and Risk Management" in this MD&A and in our other public filings).*

*The purpose of our funds flow sensitivity is to assist readers in understanding our expected and targeted financial results, and this information may not be appropriate for other purposes. The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.*

# Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2015, our internal control over financial reporting is effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2015, has been audited by Deloitte LLP, the Independent Registered Public Accounting Firm, who also audited the Company's Consolidated Financial Statements for the year ended December 31, 2015.

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

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

Calgary, Alberta
February 19, 2016

# Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Enerplus Corporation

We have audited the internal control over financial reporting of Enerplus Corporation and subsidiaries (the "Company") as of December 31, 2015, based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the consolidated financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2015 of the Company and our report dated February 19, 2016 expressed an unmodified/unqualified opinion on those consolidated financial statements.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants

February 19, 2016
Calgary, Canada

# Management's Responsibility for Financial Statements

In management's opinion, the accompanying consolidated financial statements of Enerplus Corporation have been prepared within reasonable limits of materiality and in accordance with accounting principles generally accepted in the United States of America. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to February 18, 2016. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization.

The consolidated financial statements have been examined by Deloitte LLP, Independent Registered Public Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America. The Report of Independent Registered Public Accounting Firm outlines the scope of their examination and sets forth their opinion.

The Audit Committee, consisting exclusively of independent directors, has reviewed these statements with management and the Independent Registered Public Accounting Firm and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Company.

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

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

Calgary, Alberta
February 19, 2016

# Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Enerplus Corporation

We have audited the accompanying consolidated financial statements of Enerplus Corporation and subsidiaries (the "Company"), which comprise the consolidated balance sheets as at December 31, 2015, and December 31, 2014, and the consolidated statements of income / (loss) and comprehensive income / (loss), consolidated statements of changes in shareholders' equity, and consolidated statements of cash flows for each of the years in the three-year period ended December 31, 2015, and the notes to the consolidated financial statements.

*Management's Responsibility for the Consolidated Financial Statements*

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

*Auditor's Responsibility*

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

*Opinion*

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enerplus Corporation and subsidiaries as at December 31, 2015 and December 31, 2014, and their financial performance and their cash flows for each of the years in the three-year period ended December 31, 2015 in accordance with accounting principles generally accepted in the United States of America.

*Other Matter*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 19, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants

February 19, 2016
Calgary, Canada

# Consolidated Balance Sheets

| (CDN$ thousands) | Note | December 31, 2015 | December 31, 2014 |
|---|---|---|---|
| **Assets** | | | |
| Current assets | | | |
| Cash | | $ 7,498 | $ 2,036 |
| Accounts receivable | 3 | 132,156 | 199,745 |
| Deferred financial assets | 15 | 71,438 | 215,706 |
| Other current assets | | 9,953 | 8,241 |
| | | 221,045 | 425,728 |
| Property, plant and equipment: | | | |
| Oil and natural gas properties (full cost method) | 4 | 1,166,587 | 2,632,474 |
| Other capital assets, net | 4 | 19,686 | 20,591 |
| Property, plant and equipment | | 1,186,273 | 2,653,065 |
| Goodwill | | 657,831 | 624,390 |
| Deferred income tax asset | 13 | 516,085 | 297,312 |
| Deferred financial assets | 15 | – | 30,997 |
| **Total Assets** | | $ 2,581,234 | $ 4,031,492 |
| **Liabilities** | | | |
| Current liabilities | | | |
| Accounts payable | 6 | $ 239,950 | $ 351,006 |
| Dividends payable | | 6,196 | 18,516 |
| Current portion of long-term debt | 7 | – | 98,933 |
| Deferred financial liabilities | 15 | 4,100 | 10,826 |
| | | 250,246 | 479,281 |
| Deferred financial liabilities | 15 | 3,193 | 2,396 |
| Long-term debt | 7 | 1,223,682 | 1,037,997 |
| Asset retirement obligation | 8 | 206,359 | 288,692 |
| | | 1,433,234 | 1,329,085 |
| **Total Liabilities** | | 1,683,480 | 1,808,366 |
| **Shareholders' Equity** | | | |
| Share capital – authorized unlimited common shares, no par value<br>Issued and outstanding: December 31, 2015 – 207 million shares<br>December 31, 2014 – 206 million shares | 14 | 3,133,524 | 3,120,002 |
| Paid-in capital | 14 | 56,176 | 46,906 |
| Accumulated deficit | | (2,694,618) | (1,039,260) |
| Accumulated other comprehensive income/(loss) | | 402,672 | 95,478 |
| | | 897,754 | 2,223,126 |
| **Total Liabilities & Equity** | | $ 2,581,234 | $ 4,031,492 |

| | |
|---|---|
| **Commitments, Contingencies and Guarantees** | 16 |
| **Subsequent events** | 19 |

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

Approved on behalf of the Board of Directors:

Elliott Pew

**Elliott Pew**
Director

Robert B. Hodgins

**Robert B. Hodgins**
Director

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

| **For the year ended December 31** (CDN$ thousands) | Note | 2015 | 2014 | 2013 |
|---|---|---|---|---|
| **Revenues** | | | | |
| Oil and natural gas sales, net of royalties | 9 | $ 884,392 | $ 1,526,194 | $ 1,352,472 |
| Commodity derivative instruments gain/(loss) | 15 | 142,724 | 234,373 | (41,870) |
| | | 1,027,116 | 1,760,567 | 1,310,602 |
| **Expenses** | | | | |
| Production taxes | | 50,899 | 81,522 | 70,388 |
| Operating | | 340,483 | 348,596 | 325,181 |
| Transportation | | 114,691 | 101,183 | 58,170 |
| General and administrative | 10 | 103,870 | 105,041 | 110,260 |
| Depletion, depreciation and accretion | | 507,257 | 566,674 | 593,203 |
| Asset impairment | 5 | 1,352,428 | – | – |
| Interest | 11 | 67,378 | 63,788 | 58,337 |
| Foreign exchange(gain)/loss | 12 | 173,933 | 57,090 | 9,313 |
| Other expense/(income) | | 7,055 | (231) | (868) |
| | | 2,717,994 | 1,323,663 | 1,223,984 |
| **Income/(Loss) before Taxes** | | (1,690,878) | 436,904 | 86,618 |
| Current income tax expense/(recovery) | 13 | (16,887) | 4,998 | 7,889 |
| Deferred income tax expense/(recovery) | 13 | (150,588) | 132,830 | 30,753 |
| **Net Income/(Loss)** | | $ (1,523,403) | $ 299,076 | $ 47,976 |
| **Other Comprehensive Income/(Loss)** | | | | |
| Changes due to marketable securities (net of tax) | | | | |
| Unrealized gain/(loss) | | – | (145) | 7,136 |
| Realized (gain)/loss reclassified to net income | | – | 2,503 | (315) |
| Change in cumulative translation adjustment | | 307,194 | 143,817 | 72,867 |
| **Other Comprehensive Income/(Loss)** | | 307,194 | 146,175 | 79,688 |
| **Total Comprehensive Income/(Loss)** | | $ (1,216,209) | $ 445,251 | $ 127,664 |
| **Net Income/(Loss) per Share** | | | | |
| Basic | 14 | $ (7.39) | $ 1.46 | $ 0.24 |
| Diluted | 14 | $ (7.39) | $ 1.44 | $ 0.24 |

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

# Consolidated Statements of Changes in Shareholders' Equity

| **For the year ended December 31** (CDN$ thousands) | **2015** | **2014** | **2013** |
|---|---|---|---|
| **Share Capital** | | | |
| Balance, beginning of year | $ 3,120,002 | $ 3,061,839 | $ 2,997,682 |
| Stock Option Plan – cash | 3,205 | 31,350 | 14,838 |
| Share-based compensation – settled | 10,050 | – | – |
| Stock Option Plan – exercised | 267 | 4,978 | 3,108 |
| Stock Dividend Plan | – | 21,835 | 46,211 |
| Balance, end of year | $ 3,133,524 | $ 3,120,002 | $ 3,061,839 |
| **Paid-in Capital** | | | |
| Balance, beginning of year | $ 46,906 | $ 38,398 | $ 32,293 |
| Share-based compensation –settled | (10,050) | – | – |
| Stock Option Plan – exercised | (267) | (4,978) | (3,108) |
| Share-based compensation – non-cash | 19,587 | 13,486 | 9,213 |
| Balance, end of year | $ 56,176 | $ 46,906 | $ 38,398 |
| **Accumulated Deficit** | | | |
| Balance, beginning of year | $ (1,039,260) | $ (1,117,238) | $ (948,350) |
| Net income/(loss) | (1,523,403) | 299,076 | 47,976 |
| Dividends | (131,955) | (221,098) | (216,864) |
| Balance, end of year | $ (2,694,618) | $ (1,039,260) | $ (1,117,238) |
| **Accumulated Other Comprehensive Income/(Loss)** | | | |
| Balance, beginning of year | $ 95,478 | $ (50,697) | $ (130,385) |
| Changes due to marketable securities (net of tax) | | | |
| Unrealized gain/(loss) | – | (145) | 7,136 |
| Realized (gain)/loss reclassified to net income | – | 2,503 | (315) |
| Change in cumulative translation adjustment | 307,194 | 143,817 | 72,867 |
| Balance, end of year | $ 402,672 | $ 95,478 | $ (50,697) |
| **Total Shareholders' Equity** | $ 897,754 | $ 2,223,126 | $ 1,932,302 |

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

# Consolidated Statements of Cash Flows

| **For the year ended December 31** (CDN$ thousands) | **Note** | **2015** | **2014** | **2013** |
|---|---|---|---|---|
| **Operating Activities** | | | | |
| Net income/(loss) | | $ (1,523,403) | $ 299,076 | $ 47,976 |
| Non-cash items add/(deduct): | | | | |
| Depletion, depreciation and accretion | | 507,257 | 566,674 | 593,203 |
| Asset impairment | 5 | 1,352,428 | – | – |
| Changes in fair value of derivative instruments | 15 | 169,336 | (242,038) | 35,088 |
| Deferred income tax expense/(recovery) | 13 | (150,588) | 132,830 | 30,753 |
| Foreign exchange (gain)/loss on debt and working capital | 12 | 160,791 | 68,202 | 19,747 |
| Share-based compensation | 14 | 19,587 | 13,486 | 9,213 |
| Amortization of debt issue costs | | 922 | 968 | 793 |
| Asset divestment (gain)/loss | | – | 2,798 | (367) |
| Derivative settlement on senior notes | 7 | (43,229) | 17,024 | 17,827 |
| Asset retirement obligation expenditures | 8 | (14,935) | (19,409) | (16,606) |
| Changes in non-cash operating working capital | 18 | (12,830) | (52,414) | 28,851 |
| Cash flow from operating activities | | 465,336 | 787,197 | 766,478 |
| **Financing Activities** | | | | |
| Proceeds from the issuance of shares | 14 | 3,205 | 31,350 | 14,838 |
| Cash dividends | 14 | (131,955) | (199,263) | (170,653) |
| Change in bank credit facility | | 6,626 | (136,918) | (45,556) |
| Proceeds/(repayment) of senior notes | | (103,198) | 167,497 | (46,814) |
| Derivative settlement on senior notes | 7 | 43,229 | (17,024) | (17,827) |
| Changes in non-cash financing working capital | | (12,320) | 263 | 368 |
| Cash flow from financing activities | | (194,413) | (154,095) | (265,644) |
| **Investing Activities** | | | | |
| Capital and office expenditures | | (497,875) | (817,968) | (687,905) |
| Property and land acquisitions | | (9,552) | (18,491) | (244,837) |
| Property divestments | | 286,614 | 203,576 | 365,135 |
| Sale of marketable securities | | – | 13,300 | 2,482 |
| Changes in non-cash investing working capital | | (47,586) | (17,449) | 60,604 |
| Cash flow from investing activities | | (268,399) | (637,032) | (504,521) |
| Effect of exchange rate changes on cash | | 2,938 | 2,976 | 1,477 |
| Change in cash | | 5,462 | (954) | (2,210) |
| Cash, beginning of year | | 2,036 | 2,990 | 5,200 |
| **Cash, end of year** | | $ 7,498 | $ 2,036 | $ 2,990 |

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

# Notes to Consolidated Financial Statements

### 1) REPORTING ENTITY

These annual audited Consolidated Financial Statements ("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 Consolidated Financial Statements were authorized for issue by the Board of Directors on February 18, 2016.

### 2) SIGNIFICANT ACCOUNTING POLICIES

The following significant accounting policies are presented to assist the reader in evaluating these Consolidated Financial Statements and, together with the following notes, are an integral part of the Consolidated Financial Statements.

#### a) Basis of Preparation

Enerplus' Consolidated Financial Statements have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). These Consolidated Financial Statements present Enerplus' financial position as at December 31, 2015 and 2014 and results of operations for the years ended December 31, 2015, and the 2014 and 2013 comparative years.

i. Reporting Currency

These Consolidated Financial Statements are presented in Canadian dollars, which is Enerplus' reporting currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand unless otherwise indicated.

ii. Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Significant estimates made by management include: oil and natural gas reserves and related present value of future cash flows, depreciation, depletion and accretion ("DD&A"), impairment, asset retirement obligations, income taxes, income tax asset values, impairment assessments of goodwill and the fair value of derivative instruments. Enerplus uses the most current information available and exercises judgment in making these estimates and assumptions. In the opinion of management, these Consolidated Financial Statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies.

iii. Basis of Consolidation

These Consolidated Financial Statements include the accounts of Enerplus and its subsidiaries. Intercompany balances and transactions are eliminated on consolidation. Interests in jointly controlled oil and natural gas assets are accounted for following the concept of undivided interest, whereby Enerplus' proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

The acquisition method of accounting is used to account for acquisitions of companies and assets that meet the definition of a business under U.S. GAAP. The cost of an acquisition is measured as the fair value of the assets transferred, equity instruments issued and liabilities incurred or assumed at the acquisition date. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date.

#### b) Revenue

Revenue associated with the sale of oil and natural gas is recognized when title passes from the Company to its customers if collectability is reasonably certain and the sales price is determinable. Revenue is measured at the fair value of the consideration received or receivable based on price, volumes delivered and contractual delivery points. Realized gains and losses from commodity price risk management activities are recognized in revenue when the contract is settled. Unrealized gains and losses on commodity price risk management activities are recognized in revenue based on the changes in fair value of the contracts at the end of the respective reporting period.

**c) Transportation**

We generally sell oil and natural gas under two types of agreements which are common in our industry. Both types of agreements include a transportation charge. One is a net-back arrangement, under which we sell crude oil or natural gas at the wellhead and collect a price, net of the transportation incurred by the purchaser. In this case, we record sales at the price received from the purchaser, net of transportation costs. Under the other arrangement, we sell crude oil or natural gas at a specific delivery point, pay transportation to a third party and receive proceeds from the purchaser with no transportation deduction. In this case, we record the transportation to a third party and receive proceeds from the purchaser with no transportation deduction. In this case we record the transportation cost as transportation expense on the Consolidated Statements of Income/(Loss). Due to these two distinct selling arrangements, our computed realized prices, before the impact of derivative instruments, includes revenues which are reported under two separate bases.

**d) Oil and Natural Gas Properties**

Enerplus uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs incurred in finding oil and natural gas reserves are capitalized, including general and administrative costs directly attributable to these activities. These costs are recorded on a country-by-country cost centre basis as oil and natural gas properties subject to depletion ("full cost pool"). Costs associated with production and general corporate activities are expensed as incurred.

The net carrying value of both proved and unproved oil and natural gas properties is depleted using the unit of production method using proved reserves, as determined using a constant price assumption of the simple average of the preceding twelve months' first-day-of-the-month commodity prices ("SEC prices"). The depletion calculation takes into account estimated future development costs necessary to bring those reserves into production.

Under full cost accounting, a ceiling test is performed on a cost centre basis. Enerplus limits capitalized costs of proved and unproved oil and natural gas properties, net of accumulated depletion and deferred income taxes, to the estimated future net cash flows from proved oil and natural gas reserves discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties ("the ceiling"). If such capitalized costs exceed the ceiling, a write-down equal to that excess is recorded as a non-cash charge to net income. A write-down is not reversed in future periods even if higher oil and natural gas prices subsequently increase the ceiling.

Under full cost accounting rules, proceeds on property dispositions are accounted for as a reduction to the full cost pool with no recognition of a gain or loss, unless the deduction significantly alters the relationship between capitalized costs and proved reserves in the cost centre.

**e) Other Capital Assets**

Other capital assets are recorded at historical cost, net of depreciation, and include furniture, fixtures, leasehold improvements and computer equipment. Depreciation is calculated on a straight-line basis over the estimated useful life of the respective asset. The cost of repairs and maintenance is expensed as incurred.

**f) Goodwill**

Enerplus recognizes goodwill relating to corporate acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. The portion of goodwill that relates to U.S. operations fluctuates due to changes in foreign exchange rates. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes. During the 2015 and 2014 years there were no additions to goodwill.

Impairment testing is performed on an annual basis or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus performs a qualitative assessment by evaluating potential indicators of impairment, and if it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to earnings in the Consolidated Statements of Income/(Loss).

### g) Asset Retirement Obligations

Enerplus' oil and natural gas operating activities give rise to dismantling, decommissioning and site remediation activities. Enerplus recognizes a liability for the estimated present value of the future asset retirement obligation liability at each balance sheet date. The associated asset retirement cost is capitalized and amortized over the same period as the underlying asset. Changes in the estimated liability and related asset retirement cost can arise as a result of revisions in the estimated amount or timing of cash flows.

Depletion of asset retirement costs and increases in asset retirement obligations resulting from the passage of time are recorded as depletion and accretion, respectively, which are included in depreciation, depletion and accretion and charged against net income in the Consolidated Statements of Income/(Loss).

### h) Income Tax

Enerplus uses the liability method of accounting for income taxes. Deferred income tax assets and liabilities are recorded on the temporary differences between the accounting and income tax basis of assets and liabilities, using the enacted tax rates expected to apply when the temporary differences are expected to reverse. Deferred tax assets are reviewed each period and a valuation allowance is provided if, after considering available evidence, it is more likely than not that a deferred tax asset will not be realized. Enerplus considers both positive and negative evidence including historic and expected future taxable income, reversing existing temporary differences and tax basis carry forward periods in making this assessment. A valuation allowance is removed in any period where available evidence indicates all or a portion of the valuation allowance is no longer required. The financial statement effect of an uncertain tax position is recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxation authority. Penalties and interest related to income tax is recognized in income tax expense.

### i) Financial Instruments

#### i. Fair Value Measurements

Financial instruments are initially recorded at fair value, defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. For financial instruments carried at fair value, inputs used in determining the fair value are characterized according to the following fair value hierarchy:

Level 1 – Inputs represent quoted market prices in active markets for identical assets or liabilities.

Level 2 – Inputs other than quoted market prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted market prices for similar assets or liabilities in active markets or other market corroborated inputs.

Level 3 – Inputs that are not observable from objective sources, such as forward prices supported by little or no market activity or internally developed estimates of future cash flows used in a present value model.

Subsequent measurement is based on classification of the financial instrument into one of the following five categories: held-for-trading, held-to-maturity, available-for-sale, loans and receivables or other financial liabilities.

#### ii. Non-derivative financial instruments

From time-to-time, Enerplus may hold certain marketable securities in entities involved in the oil and gas industry which would be included in other assets on the Consolidated Balance Sheets. These investments may include both publicly traded and unlisted marketable securities. Publicly traded investments are classified as available-for-sale and carried at fair value based on a Level 1 designation, with changes in fair value recorded in other comprehensive income. Fair values are determined by reference to quoted market bid prices at the close of business on the balance sheet date. Unlisted marketable securities are carried at cost. When investments are ultimately sold any gains or losses are recognized in net income and any unrealized gains or losses previously recognized in other comprehensive income are reversed.

Enerplus capitalizes transaction costs and premiums on long-term debt. These costs are amortized using the effective interest method.

#### iii. Derivative financial instruments

Enerplus enters into financial derivative contracts in order to manage its exposure to market risks from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Enerplus has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though it considers most of these contracts to be economic hedges. As a result, all financial derivative contracts are classified as held-for-trading and are recorded at fair value based on a Level 2 designation, with changes in fair value recorded in net income. The fair values of these derivative instruments are generally based on an estimate of the amounts that would be paid or received to settle these instruments at the balance sheet date. Enerplus' accounting policy is to not offset the fair values of its financial derivative assets and liabilities.

Enerplus' crude oil, natural gas and natural gas liquids physical delivery purchase and sales contracts qualify as normal purchases and sales as they are entered into and held for the purpose of receipt or delivery of products in accordance with the Company's expected purchase, sale or usage requirements. As such, these contracts are not considered derivative financial instruments. Settlements on these physical contracts are recognized in net income over the term of the contracts as they occur.

**j) Foreign Currency**

i. Foreign currency transactions

Transactions denominated in foreign currencies are translated to Canadian dollars using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Foreign currency differences arising on translation are recognized in net income in the period in which they arise.

ii. Foreign operations

Assets and liabilities of Enerplus' U.S. operations are translated into Canadian dollars at period end exchange rates while revenues and expenses are translated using average rates for the period. Gains and losses from the translation are deferred and included in the cumulative translation adjustment ("CTA") which is recorded in accumulated other comprehensive income ("AOCI").

**k) Share-Based Compensation**

Enerplus' share-based compensation plans include its cash-settled Restricted Share Unit ("RSU"), Performance Share Unit ("PSU") and Director Share Unit ("DSU") plans, its equity-settled RSU and PSU plans, as well as Enerplus' Stock Option Plan.

i. RSU, PSU, and DSU plans

Under Enerplus' RSU plan, employees receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and vests one-third each year for three years. The value upon vesting is based on the value of the underlying notional shares plus notional accrued dividends over the vesting period.

Under Enerplus' PSU plan, executives and management receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and they vest at the end of three years. The value upon vesting is based on value of the underlying shares plus notional accrued dividends along with a multiplier that ranges from 0 to 2 depending on Enerplus' performance compared to the TSX oil and gas index over the vesting period.

Under Enerplus' DSU plan, directors receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded is based on the annual retainer value and they vest upon the director leaving the Board. The value upon vesting is based on the value of the underlying notional shares plus notional accrued dividends over the vesting period.

RSU and PSU grants made prior to 2014 are settled in cash. RSU and PSU grants made from 2014 onwards are settled through the issuance of treasury shares. All DSU grants are settled in cash.

Enerplus recognizes a liability in respect of its cash-settled long-term incentive plans based on their estimated fair value. The liability is re-measured at each reporting date and at settlement date with any changes in the fair value recorded as share-based compensation, included in general and administrative expense.

Enerplus recognizes non-cash share-based compensation expense over the vesting period of the equity-settled long-term incentive plans, based on the estimated grant date fair value of the respective awards. Share-based compensation charges are recorded on the Consolidated Statements of Income/(Loss) with an offset to paid-in capital. Each period, management performs an estimate of the PSU plan multiplier. Any differences that arise between the actual multiplier on plan settlement and management's estimate is recorded to share-based compensation. On settlement of these plans, amounts previously recorded to paid-in capital are reclassified to share capital.

ii. Stock options

Under Enerplus' Stock Option Plan, employees are granted options to purchase common shares of the Company at an exercise price equal to the market value of the common shares on the date the options are granted. Options granted are exercisable in thirds over the three year vesting schedule and expire seven years after the date the options are granted. Enerplus uses the Black-Scholes option pricing model to calculate the grant date fair value of stock options granted under the Company's Stock Option Plan. This amount is charged to earnings as share-based compensation over the vesting period of the options, with a corresponding increase in paid-in capital. When options are exercised, the proceeds, together with the amount recorded in paid-in capital, are recorded to share capital.

The Company is authorized to issue up to 10% of outstanding common shares from treasury in relation to a combination of its Stock Option Plan and equity-settled RSU and PSU plans, with a maximum of 50% of this allotment being issued pursuant to the equity-settled RSU and PSU plans. In 2014, the Company suspended the issuance of stock options.

**l) Net Income Per Share**

Basic net income per common share is computed by dividing net income by the weighted average number of common shares outstanding during the period.

For the diluted net income per common share calculation, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income. The weighted average number of diluted shares is calculated in accordance with the treasury stock method which assumes that the proceeds received from the exercise of all stock options would be used to repurchase common shares at the average market price.

**m) Contingencies**

Liabilities for loss contingencies arising from claims, assessments, litigation, environmental and other sources are recognized when it is probable that a liability has been incurred and the amount can be reasonably estimated. Contingencies are adjusted as additional information becomes available or circumstances change.

**n) Accounting Changes and Recent Pronouncements Issued**

i. Recently adopted accounting standards

Effective January 1, 2015, Enerplus adopted the following Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"):

- ASU 2015-17, *Balance Sheet Classification of Deferred Taxes* was issued by the FASB in November of 2015 and requires the presentation of deferred tax assets and liabilities as noncurrent in the Consolidated Balance Sheets. The amendments are effective for annual periods beginning after December 15, 2016, and can be early adopted. Enerplus has elected to early adopt this ASU and has applied it retrospectively to the comparative 2014 period. Refer to Note 13 for details on the impact of this adoption.
- In 2015 we also adopted ASU 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity,* which changed the requirements for reporting discontinued operations under Subtopic 205-20. The adoption of this ASU did not have a material impact on the Consolidated Financial Statements.

ii. Future accounting changes

Enerplus will adopt the following ASU's issued by the FASB, which have been issued but are not yet effective. The adoption of these standards is not expected to have a material impact on Enerplus' financial statements.

- ASU 2014-09, *Revenue from Contracts with Customers* – effective January 1, 2018
- ASU 2014-12, *Compensation – Stock Compensation: Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period* – effective January 1, 2016
- ASU 2015-02, *Amendments to the Consolidation Analysis* – effective January 1, 2016
- ASU 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* – effective January 1, 2016

- ASU 2016-01, *Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities* – effective January 1, 2018

## 3) ACCOUNTS RECEIVABLE

| ($ thousands) | December 31, 2015 | December 31, 2014 |
|---|---|---|
| Accrued receivables | $ 91,378 | $ 136,949 |
| Accounts receivable – trade | 22,615 | 41,618 |
| Current income tax receivable | 21,410 | 23,900 |
| Allowance for doubtful accounts | (3,247) | (2,722) |
| Total accounts receivable | $ 132,156 | $ 199,745 |

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

| **As at December 31, 2015**<br>($ thousands) | Cost | Accumulated Depletion, Depreciation, and Impairment | Net Book Value |
|---|---|---|---|
| Oil and natural gas properties | $ 13,541,670 | $ 12,375,083 | $ 1,166,587 |
| Other capital assets | 105,124 | 85,438 | 19,686 |
| Total PP&E | $ 13,646,794 | $ 12,460,521 | $ 1,186,273 |

| **As at December 31, 2014**<br>($ thousands) | Cost | Accumulated Depletion, Depreciation, and Impairment | Net Book Value |
|---|---|---|---|
| Oil and natural gas properties | $ 12,478,953 | $ 9,846,479 | $ 2,632,474 |
| Other capital assets | 97,893 | 77,302 | 20,591 |
| Total PP&E | $ 12,576,846 | $ 9,923,781 | $ 2,653,065 |

## 5) IMPAIRMENT

### a) Impairment of PP&E

| ($ thousands) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Oil and natural gas properties: | | | |
| Canada cost centre | $ 286,700 | $ – | $ – |
| U.S. cost centre | 1,065,728 | – | – |
| Total impairment expense | $ 1,352,428 | $ – | $ – |

The impairments for the period ended December 31, 2015 were 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 test as at December 31, 2015, 2014 and 2013:

| 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 |
|---|---|---|---|---|---|
| 2015 | $ 50.28 | 1.27 | $ 59.38 | $ 2.58 | $ 2.69 |
| 2014 | 94.99 | 1.09 | 94.84 | 4.30 | 4.60 |
| 2013 | 96.94 | 1.03 | 93.19 | 3.67 | 3.16 |

### b) Goodwill Impairment

Goodwill impairment testing is performed annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus' annual goodwill impairment assessment as at December 31, 2015 indicated no impairment.

## 6) ACCOUNTS PAYABLE

| ($ thousands) | December 31, 2015 | December 31, 2014 |
|---|---|---|
| Accrued payables | $ 167,253 | $ 239,773 |
| Accounts payable – trade | 72,697 | 111,233 |
| Total accounts payable | $ 239,950 | $ 351,006 |

## 7) DEBT

| ($ thousands) | December 31, 2015 | December 31, 2014 |
|---|---|---|
| Current: | | |
| Senior notes | $ – | $ 98,933 |
| | – | 98,933 |
| Long-term: | | |
| Bank credit facility | $ 86,543 | $ 79,917 |
| Senior notes | 1,137,139 | 958,080 |
| | 1,223,682 | 1,037,997 |
| Total debt | $ 1,223,682 | $ 1,136,930 |

### Bank Credit Facility

Enerplus has a senior unsecured, covenant-based, $800 million bank credit facility that matures on October 31, 2018. Drawn fees range between 150 and 315 basis points over bankers' acceptance rates, with current drawn fees of 205 basis points. Standby fees on the undrawn portion of the facility are based on 20% of the drawn pricing. The Company has the ability to request an extension of the facility each year or repay the entire balance at the end of the term. At December 31, 2015 Enerplus had $86.5 million (December 31, 2014 – $79.9 million) drawn and was in compliance with all financial covenants under the facility. During 2015 a fee of $0.3 million (2014 – $0.6 million, 2013 – $0.7 million) was paid to extend the facility. The weighted average interest rate on the facility for the year ended December 31, 2015 was 2.2% (December 31, 2014 – 2.8%).

### Senior Notes

On June 18, 2015 Enerplus made bullet payments on both its US$40 million and $40 million senior notes, which were issued on June 18, 2009. On October 1, 2015 Enerplus made its fifth and final principal repayment of US$10.8 million on the US$54.0 million senior notes issued on October 1, 2003 and settled the corresponding foreign exchange swap. The final principal repayment totaled $11.0 million and a gain of $3.3 million was realized on the foreign exchange swap, which was recorded as a realized foreign exchange gain on the Consolidated Statements of Income/ (Loss).

On September 3, 2014 Enerplus closed a private placement of senior unsecured notes raising gross proceeds of US$200.0 million. The notes rank equally with the bank credit facility and other outstanding senior notes. The notes have a twelve year amortizing term and ten year average life with a fixed coupon rate of 3.79%.

On June 19, 2014 Enerplus made its fifth and final principal repayment on the US$175.0 million senior notes issued on June 19, 2002 and the associated cross currency interest rate swap principal settlement for a total of $53.7 million.

The terms and rates of the Company's outstanding senior notes are detailed 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$200,000 | $ 276,785 |
| 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 | 27,678 |
| May 15, 2012 | May 15 and Nov 15 | 5 equal annual installments beginning May 15, 2020 | 4.40% | US$355,000 | US$355,000 | 491,293 |
| June 18, 2009 | June 18 and Dec 18 | 5 equal annual installments beginning June 18, 2017 | 7.97% | US$225,000 | US$225,000 | 311,383 |
| | | | | Total carrying value | | $ 1,137,139 |
| | | | | Current portion | | – |
| | | | | Long-term portion | | $ 1,137,139 |

At December 31, 2015 Enerplus was in full compliance with all financial covenants under the senior notes.

### 8) ASSET RETIREMENT OBLIGATION

At December 31, 2015 Enerplus estimated the present value of its asset retirement obligation to be $206.4 million (December 31, 2014 – $288.7 million) based on a total undiscounted liability of $556.4 million (December 31, 2014 – $730.9 million). The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.91% at December 31, 2015 (December 31, 2014 – 5.92%). Enerplus' asset retirement obligation expenditures are expected to be incurred over the next 65 years with the majority between 2026 and 2055. For the year-ended December 31, 2015, changes in estimate related to decreases in estimated future abandonment and reclamation costs as a result of a lower cost environment.

| ($ thousands) | December 31, 2015 | December 31, 2014 |
|---|---|---|
| Balance, beginning of year | $ 288,692 | $ 291,761 |
| Change in estimates | (35,386) | 4,378 |
| Property acquisition and development activity | 761 | 1,778 |
| Divestments | (48,748) | (4,313) |
| Settlements | (14,935) | (19,409) |
| Accretion expense | 15,975 | 14,497 |
| Balance, end of year | $ 206,359 | $ 288,692 |

### 9) OIL AND NATURAL GAS SALES

| ($ thousands) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Oil and natural gas sales | $ 1,052,382 | $ 1,849,312 | $ 1,616,798 |
| Royalties[1] | (167,990) | (323,118) | (264,326) |
| Oil and natural gas sales, net of royalties | $ 884,392 | $ 1,526,194 | $ 1,352,472 |

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

### 10) GENERAL AND ADMINISTRATIVE EXPENSE

| ($ thousands) | 2015 | 2014 | 2013 |
|---|---|---|---|
| General and administrative expense | $ 81,312 | $ 83,493 | $ 83,235 |
| Share-based compensation expense | 22,558 | 21,548 | 27,025 |
| General and administrative expense | $ 103,870 | $ 105,041 | $ 110,260 |

## 11) INTEREST EXPENSE

| ($ thousands) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Realized: | | | |
| Interest on bank debt and senior notes | $ 66,456 | $ 62,240 | $ 56,716 |
| Unrealized: | | | |
| Cross currency interest rate swap (gain)/loss | – | 580 | 1,306 |
| Interest rate swap (gain)/loss | – | – | (478) |
| Amortization of debt issue costs | 922 | 968 | 793 |
| Interest expense | $ 67,378 | $ 63,788 | $ 58,337 |

## 12) FOREIGN EXCHANGE

| ($ thousands) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Realized: | | | |
| Foreign exchange (gain)/loss | $ (8,705) | $ 11,165 | $ 17,596 |
| Unrealized: | | | |
| Translation of U.S. dollar debt and working capital (gain)/loss | 160,791 | 68,202 | 19,747 |
| Cross currency interest rate swap (gain)/loss | – | (16,128) | (19,920) |
| Foreign exchange swap (gain)/loss | 21,847 | (6,149) | (8,110) |
| Foreign exchange (gain)/loss | $ 173,933 | $ 57,090 | $ 9,313 |

## 13) INCOME TAXES

Enerplus' provision for income tax is a follows:

| ($ thousands) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Current tax expense/(recovery) | | | |
| Canada | $ (795) | $ (543) | $ (621) |
| United States | (16,092) | 5,541 | 8,510 |
| Current tax expense/(recovery) | (16,887) | 4,998 | 7,889 |
| Deferred Tax expense/(recovery) | | | |
| Canada | $ (52,603) | $ 64,746 | $ (21,166) |
| United States | (97,985) | 68,084 | 51,919 |
| Deferred tax expense/(recovery) | (150,588) | 132,830 | 30,753 |
| Income tax expense/(recovery) | $ (167,475) | $ 137,828 | $ 38,642 |

In 2015, there was no deferred income tax recognized in Other Comprehensive Income compared to a $0.3 million recovery in 2014 and an expense of $1.0 million in 2013.

The following provides a reconciliation of income taxes calculated at the Canadian statutory rate to the actual income taxes:

| ($ thousands) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Income/(loss) before taxes | | | |
| Canada | $ (500,113) | $ 247,856 | $ (74,946) |
| United States | (1,190,765) | 189,048 | 161,564 |
| Total income/(loss) before taxes | (1,690,878) | 436,904 | 86,618 |
| Canadian statutory rate | 27.00% | 25.35% | 25.35% |
| Expected income tax expense/(recovery) | $ (456,537) | $ 110,755 | $ 21,958 |
| Impact on taxes resulting from: | | | |
| Foreign tax rate differential | $ (173,388) | $ 11,242 | $ 10,407 |
| Statutory and other rate differences | (6,421) | (38) | (1,976) |
| Change in valuation allowance | 443,655 | 8,007 | (690) |
| Non-taxable capital (gains)/losses | 23,450 | 8,318 | 4,884 |
| Share-based compensation | 4,395 | 2,636 | 2,335 |
| Other | (2,629) | (3,092) | 1,724 |
| Income tax expense/(recovery) | $ (167,475) | $ 137,828 | $ 38,642 |

During the year the Alberta Provincial tax rate change resulted in an increase in the Canadian statutory rate by 1.65% for the year.

Deferred income tax asset (liability) consists of the following temporary differences:

| ($ thousands) | 2015 | 2014 |
|---|---|---|
| Deferred income tax liabilities | | |
| Property, plant and equipment | $ – | $ (187,080) |
| Deferred financial assets and credits | (17,319) | (55,348) |
| Total deferred income tax liabilities | (17,319) | (242,428) |
| Deferred income tax assets | | |
| Property, plant and equipment | $ 382,454 | $ – |
| Tax loss carry-forwards and other credits | 672,193 | 610,177 |
| Asset retirement obligation | 57,364 | 74,335 |
| Other assets | 36,156 | 15,879 |
| Total deferred income tax assets | 1,148,167 | 700,391 |
| Less valuation allowance | (614,763) | (160,651) |
| Total deferred income tax assets, net | 533,404 | 539,740 |
| Net deferred income tax asset | $ 516,085 | $ 297,312 |

As a result of the retrospective early adoption of ASU 2015-17, Balance Sheet Classification of Deferred Taxes, Enerplus' deferred tax balances are now classified entirely as non-current. In the prior year, Enerplus reported a current deferred income tax liability of $50.8 million (January 1, 2014 – asset of $48.5 million) and a long-term deferred income tax asset of $348.1 million (January 1, 2014 – $364.4 million). The prior period balance has been updated to reflect the re-classification of deferred taxes, resulting in a long-term deferred income tax asset of $297.3 million (January 1, 2014 – $412.9 million).

Each period we assess the recoverability of our deferred tax assets to determine whether it is more likely than not all or a portion of our deferred tax assets will not be realized. In making that assessment, we consider available positive and negative evidence including future taxable income and reversing existing temporary differences. We have concluded that it is more likely than not that a portion of our deferred income tax assets will not be realized and have recorded a valuation allowance of $443.7 million for the year ended December 31, 2015 (December 31, 2014 – $8.0 million). This assessment is primarily the result of projecting future taxable income using historical 12-month trailing benchmark prices similar to the full cost ceiling test. Had we utilized forecast prices and costs to estimate future taxable income we would estimate it more likely than not expect that all of our deferred income tax assets would be realized and no valuation allowance would be required.

Loss carry-forwards and tax credits available for tax reporting purposes:

| As at December 31 ($ thousands) | 2015 | Expiration Date |
|---|---|---|
| **Canada** | | |
| Capital losses | $ 1,171,000 | Indefinite |
| Non-capital losses | 361,000 | 2028-2034 |
| **United States** | | |
| Net operating losses | $ 748,000 | 2030-2035 |
| Alternative minimum tax credits | 117,000 | Indefinite |

Changes in the balance of Enerplus' unrecognized tax benefits are as follows:

| For the years ended December 31 ($ thousands) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Balance, beginning of year | $ 17,000 | $ 18,000 | $ 18,500 |
| Increase/(decrease) for tax positions of prior years | (300) | 2,700 | (500) |
| Settlements | (1,600) | (3,700) | – |
| Balance, end of year | $ 15,100 | $ 17,000 | $ 18,000 |

If recognized, all of Enerplus' unrecognized tax benefits as at December 31, 2015 would affect Enerplus' effective income tax rate. It is not anticipated that the amount of unrecognized tax benefits will significantly change during the next 12 months.

A summary of the taxation years, by jurisdiction, that remain subject to examination by the taxation authorities are as follows:

| Jurisdiction | Taxation Years |
|---|---|
| Canada – Federal & Provincial | 2004-2015 |
| United States – Federal & State | 2008-2015 |

Enerplus and its subsidiaries file income tax returns primarily in Canada and the United States. Matters in dispute with the taxation authorities are ongoing and in various stages of completion.

## 14) SHAREHOLDERS' EQUITY

### a) Share Capital

| | 2015 | | 2014 | | 2013 | |
|---|---|---|---|---|---|---|
| **Authorized unlimited number of common shares Issued:** (thousands) | **Shares** | **Amount** | **Shares** | **Amount** | **Shares** | **Amount** |
| Balance, beginning of year | 205,732 | $ 3,120,002 | 202,758 | $ 3,061,839 | 198,684 | $ 2,997,682 |
| Issued for cash: | | | | | | |
| Stock Option Plan | 234 | 3,205 | 1,944 | 31,350 | 1,042 | 14,838 |
| Non-cash: | | | | | | |
| Share-based compensation – settled | 573 | 10,050 | – | – | – | – |
| Stock Option Plan – exercised | – | 267 | – | 4,978 | – | 3,108 |
| Stock Dividend Plan[1] | – | – | 1,030 | 21,835 | 3,032 | 46,211 |
| Balance, end of year | 206,539 | $ 3,133,524 | 205,732 | $ 3,120,002 | 202,758 | $ 3,061,839 |

(1) Effective with the October 2014 dividend, Enerplus suspended the Stock Dividend Plan.

The Company is authorized to issue an unlimited number of common shares without par value.

### b) Dividends

| ($ thousands) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Cash dividends | $ 131,955 | $ 199,263 | $ 170,653 |
| Stock dividends[1] | – | 21,835 | 46,211 |
| Dividends to shareholders | $ 131,955 | $ 221,098 | $ 216,864 |

(1) Effective with the October 2014 dividend, Enerplus suspended the Stock Dividend Plan.

For the year ended December 31, 2015 Enerplus paid dividends of $0.64 per common share totaling $132.0 million (December 31, 2014 – $1.08 per share and $221.1 million, December 31, 2013 – $1.08 per share and $216.9 million).

### c) 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) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Cash: | | | |
| Long-term incentive plans (recovery)/expense | $ 874 | $ (1,220) | $ 23,262 |
| Non-Cash: | | | – |
| Long-term incentive plans expense | 18,878 | 9,349 | |
| Stock option plan expense | 709 | 4,137 | 9,213 |
| Equity swap (gain)/loss | 2,097 | 9,282 | (5,450) |
| Share-based compensation expense | $ 22,558 | $ 21,548 | $ 27,025 |

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

In 2014, the Performance Share Unit and Restricted Share Unit 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 will continue to be settled in cash.

The following table summarizes the Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Director Share Unit ("DSU") activity for the twelve months ended December 31, 2015:

| | Cash-settled LTI Plans | | | Equity-settled LTI Plans | | |
|---|---|---|---|---|---|---|
| **For the year ended December 31, 2015** (thousands of units) | **PSU** | **RSU** | **DSU** | **PSU** | **RSU** | **Total** |
| Balance, beginning of year | 406 | 398 | 122 | 510 | 775 | 2,211 |
| Granted | – | – | 85 | 1,032 | 1,490 | 2,607 |
| Vested | (388) | (268) | (41) | (245) | (329) | (1,271) |
| Forfeited | (18) | (38) | – | (75) | (309) | (440) |
| Balance, end of year | – | 92 | 166 | 1,222 | 1,627 | 3,107 |

### Cash-settled LTI Plans

For the year ended December 31, 2015 the Company recorded cash share-based compensation expense of $0.9 million (2014 – recovery of $1.2 million, 2013 – charges of $23.3 million). For the year ended December 31, 2015, the Company made cash payments of $15.0 million related to its cash-settled plans (2014 – $14.1 million, 2013 – $11.1 million).

The following table summarizes the cumulative share-based compensation expense recognized to-date, which has been recorded to Accounts Payable on the Consolidated Balance Sheets. Unrecognized amounts will be recorded to cash share-based compensation expense over the remaining vesting terms.

| **At December 31, 2015** ($ thousands, except for years) | | PSU[1] | | RSU | | DSU | | Total |
|---|---|---|---|---|---|---|---|---|
| Cumulative recognized share-based compensation expense | $ | 264 | $ | 625 | $ | 1,078 | $ | 1,967 |
| Unrecognized share-based compensation expense | | – | | 37 | | – | | 37 |
| Intrinsic value | $ | 264 | $ | 662 | $ | 1,078 | $ | 2,004 |
| Weighted-average remaining contractual term (years) | | – | | 0.2 | | – | | |

(1) Includes estimated performance multipliers.

### Equity-settled LTI Plans

For the year ended December 31, 2015 the Company recorded non-cash share-based compensation expense of $18.9 million (2014 – $9.3 million, 2013 – nil).

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 December 31, 2015** ($ thousands, except for years) | | PSU[1] | | RSU | | Total |
|---|---|---|---|---|---|---|
| Cumulative recognized share-based compensation expense | $ | 5,345 | $ | 15,926 | $ | 21,271 |
| Unrecognized share-based compensation expense | | 5,178 | | 7,994 | | 13,172 |
| Fair value | $ | 10,523 | $ | 23,920 | $ | 34,443 |
| Weighted-average remaining contractual term (years) | | 1.6 | | 1.4 | | |

(1) Includes estimated performance multipliers.

### (ii) Stock Option Plan

The Company uses the Black-Scholes option pricing model to estimate the fair value of options granted under the Stock Option Plan. The Company did not grant any stock options for the years ended December 31, 2015 and 2014.

The following table summarizes the stock option plan activity for the year ended December 31, 2015:

| **Year ended December 31, 2015** | **Number of Options** (thousands) | | **Weighted Average Exercise Price** |
|---|---|---|---|
| Options outstanding, beginning of year | 10,368 | $ | 18.65 |
| Exercised | (234) | | 13.71 |
| Forfeited | (2,207) | | 19.38 |
| Expired | (347) | | 20.88 |
| Options outstanding, end of year | 7,580 | $ | 18.49 |
| Options exercisable, end of year | 6,415 | $ | 19.28 |

At December 31, 2015, 6,415,000 options were exercisable at a weighted average reduced exercise price of $19.28 with a weighted average remaining contractual term of 3.4 years, giving an aggregate intrinsic value of nil (December 31, 2014 – nil, December 31, 2013 – $5.2 million). The intrinsic value of options exercised during the year ended December 31, 2015 was $0.2 million (December 31, 2014 – $13.4 million, December 31, 2013 – $2.7 million).

At December 31, 2015 the total share-based compensation expense related to non-vested options not yet recognized was $0.1 million. The expense is expected to be recognized in net income over a weighted-average period of 0.2 years.

### d) Paid-in Capital

The following tables summarize the Paid-in Capital activity for the year and the ending balances as at December 31:

| ($ thousands) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Balance, beginning of year | $ 46,906 | $ 38,398 | $ 32,293 |
| Share-based compensation – settled | (10,050) | – | – |
| Stock Option Plan – exercised | (267) | (4,978) | (3,108) |
| Share-based compensation – non-cash | 19,587 | 13,486 | 9,213 |
| Balance, end of year | $ 56,176 | $ 46,906 | $ 38,398 |

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

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

| (thousands, except per share amounts) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Net income/(loss) | $ (1,523,403) | $ 299,076 | $ 47,976 |
| Weighted average shares outstanding – Basic | 206,205 | 204,510 | 200,567 |
| Dilutive impact of share-based compensation[1] | – | 2,914 | 837 |
| Weighted average shares outstanding – Diluted | 206,205 | 207,424 | 201,404 |
| Net income/(loss) per share | | | |
| Basic | $ (7.39) | $ 1.46 | $ 0.24 |
| Diluted | $ (7.39) | $ 1.44 | $ 0.24 |

(1) For the year ended December 31, 2015 the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the loss per share.

## 15) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

### a) Fair Value Measurements

At December 31, 2015, the carrying value of 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 December 31, 2015 senior notes included in long-term debt had a carrying value of $1,137.2 million and a fair value of $1,220.8 million (December 31, 2014 – $1,057.0 million and $1,150.0 million, respectively).

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

### b) Derivative Financial Instruments

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

The following tables summarize the change in fair value for the respective years:

| **Gain/(Loss)** ($ thousands) | December 31, 2015 | December 31, 2014 | December 31, 2013 | Income Statement Presentation |
|---|---|---|---|---|
| Interest Rate Swaps | $ – | $ – | $ 478 | Interest expense |
| Cross Currency Interest Rate Swap: | | | | |
| Interest | – | (580) | (1,306) | Interest expense |
| Foreign Exchange | – | 16,128 | 19,920 | Foreign exchange |
| Foreign Exchange Derivatives | (21,847) | 6,149 | 8,110 | Foreign exchange |
| Electricity Swaps | (408) | (1,275) | 758 | Operating expense |
| Equity Swaps | (2,097) | (9,282) | 5,450 | General and administrative expense |
| Commodity Derivative Instruments: | | | | |
| Oil | (99,790) | 182,019 | (65,504) | Commodity derivative instruments |
| Gas | (45,194) | 48,879 | (2,994) | |
| Total Unrealized Gain/(Loss) | $ (169,336) | $ 242,038 | $ (35,088) | |

The following table summarizes the effect of Enerplus' commodity derivative instruments on the Consolidated Statements of Income/(Loss):

| ($ thousands) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Change in fair value gain/(loss) | $ (144,984) | $ 230,898 | $ (68,498) |
| Net realized cash gain/(loss) | 287,708 | 3,475 | 26,628 |
| Commodity derivative instruments gain/(loss) | $ 142,724 | $ 234,373 | $ (41,870) |

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

| | December 31, 2015 | | | December 31, 2014 | | | |
|---|---|---|---|---|---|---|---|
| | Assets | Liabilities | | Assets | | Liabilities | |
| ($ thousands) | Current | Current | Long-term | Current | Long-term | Current | Long-term |
| Foreign Exchange Derivatives | $ – | $ – | $ – | $ 1,616 | $ 28,665 | $ 8,434 | $ – |
| Electricity Swaps | – | 1,776 | – | – | – | 1,368 | – |
| Equity Swaps | – | 2,324 | 3,193 | – | – | 1,024 | 2,396 |
| Commodity Derivative Instruments: | | | | | | | |
| Oil | 67,397 | – | – | 167,187 | – | – | – |
| Gas | 4,041 | – | – | 46,903 | 2,332 | – | – |
| Total | $ 71,438 | $ 4,100 | $ 3,193 | $ 215,706 | $ 30,997 | $ 10,826 | $ 2,396 |

### c) Risk Management

In the normal course of operations, Enerplus is exposed to various market risks, including commodity prices, foreign exchange, interest rates and equity prices, credit risk and liquidity risk.

### (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 Enerplus' price risk management positions at February 3, 2016:

*Crude Oil Instruments:*

| Instrument Type(1) | bbls/day | US$/bbl |
|---|---|---|
| Jan 1, 2016 – Mar 31, 2016 | | |
| WTI Swap | 9,000 | 55.82 |
| WTI Purchased Put | 8,000 | 64.38 |
| WTI Sold Call | 8,000 | 79.38 |
| WTI Sold Put | 8,000 | 50.13 |
| WCS Differential Swap | 3,000 | (14.03) |
| MSW Differential Swap | 1,000 | (3.50) |
| Apr 1, 2016 – Jun 30, 2016 | | |
| WTI Swap | 3,000 | 64.28 |
| WTI Purchased Put | 8,000 | 64.38 |
| WTI Sold Call | 8,000 | 79.38 |
| WTI Sold Put | 8,000 | 50.13 |
| WCS Differential Swap | 3,000 | (14.03) |
| MSW Differential Swap | 1,000 | (3.50) |
| Jul 1, 2016 – Dec 31, 2016 | | |
| WTI Purchased Put | 8,000 | 63.98 |
| WTI Sold Call | 8,000 | 79.63 |
| WTI Sold Put | 8,000 | 49.78 |
| WCS Differential Swap | 3,000 | (14.03) |
| MSW Differential Swap | 1,000 | (3.50) |

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

*Natural Gas Instruments:*

| Instrument Type(1) | MMcf/day | US$/Mcf |
|---|---|---|
| Jan 1, 2016 – Jan 31, 2016 | | |
| NYMEX Purchased Put | 25.0 | 3.00 |
| NYMEX Sold Put | 25.0 | 2.50 |
| NYMEX Sold Call | 25.0 | 3.75 |
| Feb 1, 2016 – Mar 31, 2016 | | |
| NYMEX Swap | 25.0 | 2.48 |
| NYMEX Purchased Put | 25.0 | 3.00 |
| NYMEX Sold Put | 25.0 | 2.50 |
| NYMEX Sold Call | 25.0 | 3.75 |
| Apr 1, 2016 – Oct 31, 2016 | | |
| NYMEX Swap | 50.0 | 2.53 |
| NYMEX Purchased Put | 25.0 | 3.00 |
| NYMEX Sold Put | 25.0 | 2.50 |
| NYMEX Sold Call | 25.0 | 3.75 |
| Nov 1, 2016 – Dec 31, 2016 | | |
| NYMEX Swap | 25.0 | 2.48 |
| NYMEX Purchased Put | 25.0 | 3.00 |
| NYMEX Sold Put | 25.0 | 2.50 |
| NYMEX Sold Call | 25.0 | 3.75 |

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

*Electricity Instruments:*

| Instrument Type | MWh | CDN$/MWh |
|---|---|---|
| Jan 1, 2016 – Dec 31, 2016<br>AESO Power Swap(1) | 15.0 | 46.60 |
| Jan 1, 2017 – Dec 31, 2017<br>AESO Power Swap(1) | 6.0 | 44.38 |

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

*Physical Contracts:*

| Instrument Type | MMcf/day | US$/Mcf |
|---|---|---|
| Jan 1, 2016 – Oct 31, 2016<br>AECO-NYMEX Basis | 50.0 | (0.69) |
| Nov 1, 2016 – Oct 31, 2017<br>AECO-NYMEX Basis | 80.0 | (0.65) |
| Nov 1, 2017 – Oct 31, 2018<br>AECO-NYMEX Basis | 80.0 | (0.65) |
| Nov 1, 2018 – Oct 31, 2019<br>AECO-NYMEX Basis | 80.0 | (0.64) |

**Foreign Exchange Risk:**

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations and U.S. dollar 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. Enerplus manages the currency risk relating to its senior notes through the derivative instruments detailed below.

*Foreign Exchange Derivatives:*

During 2014, Enerplus entered into foreign exchange collars to hedge a portion of its foreign exchange exposure on U.S. dollar denominated oil and gas sales. In 2015, Enerplus entered into foreign exchange forward rate swaps for July through December 2015 to buy US$6 million per month at an average US/CDN rate of 1.20 to partially mitigate losses on the foreign exchange collars entered into in 2014. The foreign exchange collars and forward rate swaps matured in December 2015, and during 2015 Enerplus recognized $39.2 million in net realized foreign exchange losses (2014 – gain of $0.7 million).

During 2007 Enerplus entered into foreign exchange swaps on US$54.0 million of notional debt at an average US/CDN exchange rate of 1.02. The remaining $10.8 million notional amount under the swap was settled in October 2015 in conjunction with the final principal repayment on the US$54.0 million senior notes, resulting in a realized foreign exchange gain of $3.3 million.

During 2011 Enerplus entered into foreign exchange swaps on US$175.0 million of notional debt at approximately par. These foreign exchange swaps mature between June 2017 and June 2021 in conjunction with the principal repayments on the US$225.0 million senior notes. During 2015 Enerplus unwound these swaps and recognized a gain of $39.9 million.

*Cross Currency Interest Rate Swap ("CCIRS"):*

On June 19, 2014 the final US$35.0 million principal repayment was made on the US$175.0 million senior notes, which corresponded with the final CCIRS settlement. This resulted in a $15.8 million realized foreign exchange loss.

**Interest Rate Risk:**

At December 31, 2015, approximately 93% of Enerplus' debt was based on fixed interest rates and 7% was based on floating interest rates. At December 31, 2015 Enerplus did not have any interest rate derivatives outstanding.

**Equity Price Risk:**

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 14. Enerplus has entered into various equity swaps maturing between 2016 and 2018 and has effectively fixed the future settlement cost on 470,000 shares at a 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 December 31, 2015 approximately 61% of Enerplus' marketing receivables were with companies considered investment grade.

At December 31, 2015 approximately $2.6 million or 2% 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 off 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 uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at December 31, 2015 was $3.2 million (December 31, 2014 – $2.7 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 shareholders' capital. Enerplus' objective is to provide adequate short and longer 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.

## 16) COMMITMENTS, CONTINGENCIES AND GUARANTEES

### a) Commitments

Enerplus has the following minimum annual commitments at December 31, 2015:

| | | Minimum Annual Commitment Each Year | | | | | |
|---|---|---|---|---|---|---|---|
| ($ thousands) | Total | 2016 | 2017 | 2018 | 2019 | 2020 | Thereafter |
| Bank credit facility[1] | $ 86,543 | $ – | $ – | $ 86,543 | $ – | $ – | $ – |
| Senior notes[1] | 1,137,139 | – | 62,280 | 62,280 | 92,280 | 160,483 | 759,816 |
| Transportation commitments[2] | 189,598 | 39,464 | 30,342 | 16,033 | 14,165 | 13,134 | 76,460 |
| Processing commitments | 57,966 | 12,426 | 11,989 | 10,553 | 10,539 | 1,684 | 10,775 |
| Drilling and completions | 8,456 | 6,567 | 1,889 | – | – | – | – |
| Office leases | 103,170 | 11,640 | 11,756 | 11,680 | 10,264 | 10,816 | 47,014 |
| Total commitments[3][4] | $ 1,582,872 | $ 70,097 | $118,256 | $187,089 | $127,248 | $186,117 | $ 894,065 |

(1) Interest payments have not been included. Subsequent to December 31, 2015, Enerplus repaid US$57 million in senior notes.

(2) Subsequent to December 31, 2015, Enerplus was approved for a binding bid for interstate pipeline capacity on the Tennessee Gas Pipeline from Enerplus' Marcellus production region to downstream connections. Effective August 1, 2016, Enerplus is committed for a demand toll of up to US$0.63/Mcf on up to 30,000 Mcf/d for a maximum of 20 years, with a total estimated commitment of $148.3 million from 2016 through 2036.

(3) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.

(4) US$ commitments have been converted to CDN$ using the December 31, 2015 foreign exchange rate of 1.3840.

### b) 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.

### c) Guarantees

(i) Corporate indemnities have been provided by Enerplus to all directors and officers for various items including costs to settle suits or actions due to their association with Enerplus. Enerplus has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. Each indemnity, subject to certain exceptions, applies for so long as the indemnified person is a director or officer of Enerplus.

(ii) Enerplus may provide indemnifications in the normal course of business that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents Enerplus from making a reasonable estimate of the maximum potential amounts that may be required to be paid.

## 17) GEOGRAPHICAL INFORMATION

| **As at and for the year ended December 31, 2015** ($ thousands) | Canada | U.S. | Total |
|---|---|---|---|
| Oil and natural gas sales | $ 369,559 | $ 514,833 | $ 884,392 |
| Property, plant and equipment | 435,604 | 750,669 | 1,186,273 |
| Deferred income tax asset | 157,356 | 358,729 | 516,085 |
| Goodwill | 451,121 | 206,710 | 657,831 |

| **As at and for the year ended December 31, 2014** ($ thousands) | Canada | U.S. | Total |
|---|---|---|---|
| Oil and natural gas sales | $ 689,135 | $ 837,059 | $ 1,526,194 |
| Property, plant and equipment | 1,028,436 | 1,624,629 | 2,653,065 |
| Deferred income tax asset | 104,752 | 192,560 | 297,312 |
| Goodwill | 451,121 | 173,269 | 624,390 |

| **As at and for the year ended December 31, 2013** ($ thousands) | Canada | U.S. | Total |
|---|---|---|---|
| Oil and natural gas sales | $ 676,502 | $ 675,970 | $ 1,352,472 |
| Property, plant and equipment | 1,081,259 | 1,360,095 | 2,441,354 |
| Deferred income tax asset | 169,853 | 243,034 | 412,887 |
| Goodwill | 451,121 | 158,854 | 609,975 |

## 18) SUPPLEMENTAL CASH FLOW INFORMATION

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

| ($ thousands) | December 31, 2015 | December 31, 2014 | December 31, 2013 |
|---|---|---|---|
| Accounts receivable | $ 37,064 | $ (8,392) | $ (6,935) |
| Other current assets | (2,634) | (6,777) | (1,156) |
| Accounts payable | (47,260) | (37,245) | 36,942 |
| | $ (12,830) | $ (52,414) | $ 28,851 |

### b) Other

| ($ thousands) | December 31, 2015 | December 31, 2014 | December 31, 2013 |
|---|---|---|---|
| Income taxes paid/(received) | $ (22,274) | $ 18,087 | $ 4,448 |
| Interest paid | $ 65,498 | $ 58,416 | $ 55,957 |

## 19) SUBSEQUENT EVENTS

Subsequent to year-end, Enerplus entered into two separate agreements to sell non-core Canadian natural gas assets for proceeds of approximately $193 million, before closing adjustments. One transaction with proceeds of $183 million before adjustments has closed, and it is expected that the second transaction should close in February 2016.

Subsequent to year-end, Enerplus' Board of Directors approved a reduction in the monthly dividend from $0.03 per share to $0.01 per share, effective with the April payment.

# 5 YEAR DETAILED STATISTICAL REVIEW

| | 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|
| **Daily Production**[1] | | | | | |
| Crude oil (bbls/day) | 41,639 | 40,208 | 38,250 | 36,509 | 30,181 |
| NGLs (bbls/day) | 4,763 | 3,565 | 3,472 | 3,627 | 3,306 |
| Natural gas (Mcf/day) | 360,733 | 356,142 | 288,423 | 251,773 | 251,068 |
| BOE per day | 106,524 | 103,130 | 89,793 | 82,098 | 75,332 |
| **Drilling Activity (net wells)** | 46 | 88 | 62 | 75 | 107 |
| **Average Benchmark Pricing** | | | | | |
| WTI crude oil (US$ per bbl) | $ 48.80 | $ 93.00 | $ 97.97 | $ 94.21 | $ 95.12 |
| AECO natural gas – monthly (per Mcf) | 2.77 | 4.42 | 3.16 | 2.40 | 3.68 |
| NYMEX natural gas – last day (US$ per Mcf) | 2.66 | 4.41 | 3.65 | 2.79 | 4.04 |
| US/CDN exchange Rate | 1.28 | 1.10 | 1.03 | 1.00 | 0.99 |
| **Realized Pricing** | | | | | |
| Crude oil[2] (per bbl) | $ 48.43 | $ 86.28 | $ 85.05 | $ 78.79 | $ 83.70 |
| Natural gas liquids[2] (per bbl) | 18.06 | 51.72 | 53.20 | 53.66 | 64.94 |
| Natural gas[2] (per Mcf) | 2.15 | 3.94 | 3.42 | 2.59 | 3.92 |

| ($ thousands, except per share amounts) | 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|
| **Financial** | | | | | |
| Oil and natural gas sales[2] | $1,052,381 | $1,849,312 | $1,616,795 | $1,365,542 | $1,363,726 |
| Funds flow | 493,101 | 859,020 | 754,233 | 644,523 | 574,401 |
| Cash flow from operating activities | 465,336 | 787,197 | 766,478 | 535,689 | 624,232 |
| Cash and stock dividends to shareholders | 131,955 | 221,098 | 216,864 | 301,560 | 388,904 |
| Per share | 0.70 | 1.08 | 1.08 | 1.62 | 2.16 |
| Capital spending | 493,403 | 811,026 | 681,437 | 853,435 | 866,504 |
| Property and land acquisitions | 9,552 | 18,491 | 244,837 | 185,337 | 255,209 |
| Property Divestitures | 286,614 | 203,576 | 365,135 | 275,771 | 641,190 |
| Total net capital expenditures[3] | 220,813 | 632,883 | 567,607 | 774,862 | 491,786 |
| Total assets[11] | 2,581,234 | 4,031,492 | 3,681,799 | 3,856,083 | 5,723,312 |
| Total debt, net of current portion of long-term debt and cash | 1,216,184 | 1,035,961 | 973,595 | 1,018,799 | 901,465 |
| Adjusted payout ratio[4] | 128% | 118% | 114% | 174% | 212% |
| Net debt/funds flow ratio | 2.5x | 1.3x | 1.4x | 1.7x | 1.6x |
| **Oil and Gas Economics** | | | | | |
| Net royalty rate | 21% | 22% | 21% | 20% | 18% |
| Average realized price[2] | $ 27.07 | $ 49.13 | $ 49.32 | $ 45.48 | $ 49.57 |
| Transportation Costs | (2.95) | (2.69) | (1.77) | (1.16) | (0.89) |
| Royalties & Production Tax | (5.63) | (10.75) | (10.21) | (8.95) | (8.92) |
| Cash commodity derivative instruments | 7.40 | 0.09 | 0.81 | 0.61 | (1.21) |
| Average realized Price, Net | 25.89 | 35.78 | 38.15 | 35.98 | 38.55 |
| Cash operating expense | (8.75) | (9.23) | (9.94) | (10.27) | (10.16) |
| Operating netback, after hedging | 17.14 | 26.55 | 28.21 | 25.71 | 28.39 |
| Cash general and administrative expense | (2.11) | (2.19) | (3.25) | (2.79) | (2.99) |
| Cash interest, foreign exchange and other expenses | (2.78) | (1.42) | (1.71) | (1.42) | (1.59) |
| Taxes | 0.43 | (0.12) | (0.24) | (0.05) | (2.95) |
| Funds flow | $ 12.68 | $ 22.82 | $ 23.01 | $ 21.45 | $ 20.86 |

| ($ thousands, except per share amounts) | 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|
| **Reserves**[6] | | | | | |
| **Proved Reserves** | | | | | |
| Crude oil (Mbbls) | 131,778 | 127,007 | 118,611 | 124,759 | 116,664 |
| NGLs (Mbbls) | 10,704 | 8,137 | 8,967 | 9,236 | 9,215 |
| Conventional Natural gas (MMcf) | 183,564 | 331,709 | 409,830 | 413,906 | 476,887 |
| Shale gas (MMcf) | 625,081 | 564,583 | 411,431 | 146,127 | 92,682 |
| MBOE | 277,255 | 284,525 | 264,455 | 227,335 | 220,807 |
| **Probable Reserves** | | | | | |
| Crude oil (Mbbls) | 58,222 | 73,424 | 73,635 | 66,913 | 54,497 |
| NGLs (Mbbls) | 4,993 | 4,662 | 5,757 | 5,387 | 4,411 |
| Natural gas (MMcf) | 53,802 | 124,721 | 183,744 | 198,727 | 192,363 |
| Shale gas (MMcf) | 338,288 | 275,357 | 189,430 | 78,373 | 60,861 |
| MBOE | 128,563 | 144,766 | 141,587 | 118,483 | 101,112 |
| **Proved Plus Probable Reserves** | | | | | |
| Crude oil (Mbbls) | 189,999 | 200,431 | 192,246 | 191,672 | 171,161 |
| NGLs (Mbbls) | 15,697 | 12,798 | 14,723 | 14,623 | 13,626 |
| Conventional Natural gas (MMcf) | 237,366 | 456,430 | 593,574 | 612,634 | 669,250 |
| Shale gas (MMcf) | 963,368 | 839,940 | 600,861 | 224,500 | 153,543 |
| MBOE | 405,818 | 429,291 | 406,042 | 345,817 | 321,919 |
| **Reserves Life Index**[7] | | | | | |
| Proved (years) | 9.0 | 7.8 | 7.6 | 7.8 | 7.7 |
| Proved plus probable (years) | 12.2 | 10.7 | 10.8 | 10.9 | 9.8 |
| **Trading Information** | | | | | |
| Canadian trading summary[9] | | | | | |
| High | $ 16.09 | $ 27.05 | $ 19.96 | $ 26.94 | $ 32.83 |
| Low | 4.24 | 9.02 | 12.26 | 11.53 | 23.00 |
| Close | 4.75 | 11.19 | 19.30 | 12.90 | 25.85 |
| Volume | 550,742 | 360,805 | 214,057 | 270,710 | 180,917 |
| U.S. trading summary[10] | | | | | |
| High | $ 13.16 | $ 25.37 | $ 18.79 | $ 26.54 | $ 33.29 |
| Low | 3.01 | 7.75 | 12.03 | 11.35 | 21.65 |
| Close | 3.42 | 9.60 | 18.18 | 12.96 | 25.32 |
| Volume | 382,094 | 203,965 | 192,733 | 386,690 | 225,858 |
| Weighted average number of shares outstanding (basic) | 206,205 | 204,510 | 200,567 | 195,633 | 179,889 |
| Number of shares outstanding at December 31 | 206,539 | 205,732 | 202,758 | 198,684 | 181,159 |

(1) Production is on a company interest basis
(2) Before transportation, royalties and the effects of commodity derivative instruments
(3) Includes office capital
(4) Calculated as the sum of cash dividends to shareholders, office capital and capital spending, divided by funds flow
(5) Net of commodity derivative instruments and transportation
(6) 2014 & 2015 reserves are based on gross reserves volumes. 2013 and prior years are based on company interest reserves volumes. Company interest reserves consist of gross reserves (as defined in National Instrument 51-101) plus the Company's royalty interests. Company interest reserves are not a term defined in National Instrument 51-101 and may not be comparable to reserves disclosed by other issuers
(7) The Reserves Life Indices (RLI) are based upon year-end proved and proved plus probable reserves divided by the following year's proved and proved plus probable production volumes as forecast in the independent reserves engineering reports
(8) 2010 – Trust Units trading information. All other years – share trading information. All shares are in thousands
(9) TSX data 2010, Canadian composite trading data including TSX thereafter. Volumes are in thousands
(10) NYSE data 2010, U.S. composite trading data including NYSE thereafter. Volumes are in thousands
(11) Effective in 2015, Enerplus adopted Accounting Standards Update 2015-17: Balance Sheet Classification of Deferred Taxes, which was applied retrospectively. Comparative 2013, 2012 and 2011 amounts have not been restated to conform with current period presentation.

# SUPPLEMENTAL INFORMATION

All reserves information, including our U.S. reserves, has been prepared in accordance with Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Independent reserves evaluations have been conducted on approximately 84% of the net present value (before tax, discounted at 10%, using forecast prices and costs) of our total proved plus probable reserves at December 31, 2015. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated approximately 45% of the net present value (before tax, discounted at 10%, using forecast prices and costs) of our Canadian total proved plus probable reserves and 100% of the reserves associated with properties located in North Dakota and Montana. McDaniel also reviewed the internal evaluation completed by Enerplus on the remaining 55% of the net present value (before tax, discounted at 10% using forecast prices and costs) of our Canadian properties. Netherland, Sewell & Associates, Inc. ("NSAI") evaluated all of our reserves of our U.S. properties in Pennsylvania.

The following reserves information sets out our gross reserves volumes at December 31, 2015 by product type and reserves category under McDaniel's January 1, 2016 forecast price scenarios. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit associated with a property. It should be noted that tables may not add due to rounding.

### Forecast Price Assumptions

The estimated reserves volumes and the net present values of future net revenues ("NPV") at December 31, 2015 were based upon forecast crude oil and natural gas pricing assumptions prepared by McDaniel as of January 1, 2016. These prices were applied to the reserves evaluated by McDaniel and NSAI, along with those evaluated internally by Enerplus and reviewed by McDaniel. The base reference prices and exchange rates used by McDaniel are detailed below.

| | CRUDE OIL | | | | NATURAL GAS | | NATURAL GAS LIQUIDS | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | Edmonton Par Price | | | | |
| Year | WTI(1) ($US/bbl) | Edmonton Light(2) ($Cdn/bbl) | Alberta Heavy(3) ($Cdn/bbl) | Sask Cromer Medium(4) ($Cdn/bbl) | Alberta AECO Spot Prices ($Cdn/MMbtu) | U.S. Henry Hub Gas Price ($US/MMbtu) | Propane ($Cdn/bbl) | Butanes ($Cdn/bbl) | Condensate & Natural Gasolines ($Cdn/bbl) | Inflation Rate (%/year) | Exchange Rate ($US/$Cdn) |
| 2016 | 45.00 | 56.60 | 40.50 | 52.60 | 2.70 | 2.50 | 10.60 | 35.20 | 60.60 | 0.0 | 0.730 |
| 2017 | 53.60 | 66.40 | 47.50 | 61.80 | 3.20 | 2.95 | 18.00 | 41.30 | 70.50 | 2.0 | 0.750 |
| 2018 | 62.40 | 72.80 | 52.10 | 67.70 | 3.55 | 3.40 | 25.90 | 48.00 | 77.00 | 2.0 | 0.800 |
| 2019 | 69.00 | 80.90 | 57.80 | 75.20 | 3.85 | 3.70 | 30.30 | 56.30 | 85.10 | 2.0 | 0.800 |
| 2020 | 73.10 | 83.20 | 59.50 | 77.40 | 3.95 | 3.90 | 31.20 | 61.00 | 87.50 | 2.0 | 0.825 |
| Thereafter | (5) | (5) | (5) | (5) | (5) | (5) | (5) | (5) | (5) | 2.0 | 0.825 |

**Notes:**

(1) West Texas Intermediate at Cushing Oklahoma 40° API/0.5% sulphur.

(2) Edmonton Light Sweet 40° API/0.3% sulphur.

(3) Heavy Crude Oil 12° API at Hardisty, Alberta (after deducting blending costs to reach pipeline quality).

(4) Midale Cromer Crude Oil 29° API/2.0% sulphur.

(5) Escalation is approximately 5% per year until 2023 and approximately 2% per year thereafter.

### Reserves Summary

Enerplus' 2P reserves decreased by 23.5 million BOE at year-end 2015 to 405.8 million BOE, down from 429.3 million BOE at year-end 2014. The Corporation replaced approximately 108% of its 2015 gross production through its exploration and development program, adding 41.6 million BOE of proved plus probable reserves, including revisions. Approximately 66% of the additions, including revisions, were crude oil and NGLs, representing the replacement of 163% of the Corporation's 2015 crude oil and NGLs production. The largest amount of crude oil reserves additions, including revisions, was in the Fort Berthold crude oil property in North Dakota. The largest amount of conventional natural gas and shale gas reserves additions, including revisions, was in the Marcellus shale gas property. 26.7 million BOE of proved plus probable reserves were sold in 2015. As a result of the weak outlook for crude oil and natural gas prices, approximately 7.9 million BOE of crude oil, conventional natural gas and shale gas reserves were removed from reserves at year-end. Total proved plus probable conventional natural gas reserves, excluding shale gas, decreased by approximately 33% from year-end 2014. Total proved plus probable conventional natural gas and shale gas reserves decreased by approximately 7% from year-end 2014.

| Reserves Summary | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Tight Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Conventional Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|---|
| **Gross** | | | | | | | | |
| Proved producing | 13,551 | 25,894 | 49,820 | 89,265 | 7,310 | 156,515 | 463,425 | 199,898 |
| Proved developed non-producing | 62 | 12 | – | 74 | 423 | 5,212 | 19,065 | 9,239 |
| Proved undeveloped | 258 | 5,799 | 31,686 | 37,743 | 2,972 | 21,838 | 142,591 | 68,120 |
| Total proved | 13,871 | 31,705 | 86,202 | 131,778 | 10,704 | 183,564 | 625,081 | 277,255 |
| Total probable | 3,367 | 9,804 | 45,051 | 58,222 | 4,993 | 53,802 | 338,288 | 128,563 |
| **Proved plus probable** | **17,238** | **41,508** | **131,253** | **189,999** | **15,697** | **237,366** | **963,368** | **405,818** |
| **Net** | | | | | | | | |
| Proved producing | 11,832 | 21,164 | 40,222 | 73,218 | 5,812 | 149,537 | 372,288 | 166,001 |
| Proved developed non-producing | 56 | 11 | 3,778 | 3,845 | 337 | 3,885 | 15,296 | 7,380 |
| Proved undeveloped | 247 | 4,469 | 25,404 | 30,120 | 2,380 | 20,345 | 114,366 | 54,951 |
| Total proved | 12,135 | 25,644 | 69,405 | 107,184 | 8,528 | 173,767 | 501,951 | 228,331 |
| Total probable | 2,845 | 7,619 | 36,222 | 46,686 | 3,949 | 50,265 | 271,689 | 104,293 |
| **Proved plus probable** | **14,980** | **33,264** | **105,626** | **153,870** | **12,477** | **224,032** | **773,639** | **332,625** |

## Reserves Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a gross basis, from December 31, 2014 to December 31, 2015.

Due to changes in NI 51-101 product definitions effective July 1, 2015, 5,063 MMcf of proved reserves, 1,709 MMcf of probable reserves and 6,773 MMcf of proved plus probable reserves were moved from the December 31, 2014 Canadian conventional natural gas opening volumes to the shale gas opening volumes.

In the U.S., 68,914 Mbbls of proved reserves, 52,631 Mbbls of probable reserves and 121,545 Mbbls of proved plus probable reserves were moved from the December 31, 2014 light and medium oil opening volumes to the tight oil opening volumes. In addition, 61,048 MMcf of proved reserves, 35,632 MMcf of probable reserves and 96,410 MMcf of proved plus probable reserves in the U.S. were moved from the December 31, 2014 conventional natural gas opening volumes to the shale gas opening volumes.

PROVED RESERVES – GROSS VOLUMES (FORECAST PRICES)

| CANADA | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Tight Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Conventional Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|---|
| Proved Reserves at December 31, 2014 | 26,571 | 31,522 | – | 58,093 | 4,333 | 265,598 | 5,063 | 107,535 |
| Acquisitions | – | – | – | – | – | – | – | – |
| Dispositions | (12,183) | (7) | – | (12,190) | (844) | (37,138) | – | (19,224) |
| Discoveries | – | – | – | – | – | – | – | – |
| Extensions and Improved Recovery | 100 | 1,413 | – | 1,513 | 16 | 1,538 | – | 1,784 |
| Economic Factors | (229) | (1,767) | – | (1,996) | (194) | (23,302) | (32) | (6,079) |
| Technical Revisions | 1,982 | 3,692 | – | 5,674 | 626 | 24,304 | (480) | 10,270 |
| Production | (2,370) | (3,148) | – | (5,518) | (661) | (47,435) | (402) | (14,151) |
| **Proved Reserves at December 31, 2015** | 13,871 | 31,705 | – | 45,576 | 3,274 | 183,564 | 4,149 | 80,135 |

| UNITED STATES | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Tight Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Conventional Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|---|
| Proved Reserves at December 31, 2014 | – | – | 68,914 | 68,914 | 3,804 | – | 625,630 | 176,990 |
| Acquisitions | – | – | – | – | – | – | – | – |
| Dispositions | – | – | (313) | (313) | (17) | – | (148) | (354) |
| Discoveries | – | – | – | – | – | – | – | – |
| Extensions and Improved Recovery | – | – | 5,594 | 5,594 | 469 | – | 23,394 | 9,962 |
| Economic Factors | – | – | (1,173) | (1,173) | (95) | – | (6,722) | (2,388) |
| Technical Revisions | – | – | 22,803 | 22,803 | 4,275 | – | 60,386 | 37,142 |
| Production | – | – | (9,623) | (9,623) | (1,007) | – | (81,609) | (24,231) |
| **Proved Reserves at December 31, 2015** | – | – | 86,202 | 86,202 | 7,430 | – | 620,932 | 197,120 |

| TOTAL ENERPLUS | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Tight Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Conventional Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|---|
| Proved Reserves at December 31, 2014 | 26,571 | 31,522 | 68,914 | 127,007 | 8,137 | 265,598 | 630,694 | 284,525 |
| Acquisitions | – | – | – | – | – | – | – | – |
| Dispositions | (12,183) | (7) | (313) | (12,503) | (861) | (37,138) | (148) | (19,578) |
| Discoveries | – | – | – | – | – | – | – | – |
| Extensions and Improved Recovery | 100 | 1,413 | 5,594 | 7,107 | 485 | 1,538 | 23,394 | 11,746 |
| Economic Factors | (229) | (1,767) | (1,173) | (3,169) | (289) | (23,302) | (6,754) | (8,467) |
| Technical Revisions | 1,982 | 3,692 | 22,803 | 28,477 | 4,900 | 24,304 | 59,906 | 47,412 |
| Production | (2,370) | (3,148) | (9,623) | (15,141) | (1,667) | (47,435) | (82,011) | (38,382) |
| **Proved Reserves at December 31, 2015** | 13,871 | 31,705 | 86,202 | 131,778 | 10,704 | 183,564 | 625,081 | 277,255 |

PROBABLE RESERVES – GROSS VOLUMES (FORECAST PRICES)

| CANADA | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Tight Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Conventional Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|---|
| Probable Reserves at December 31, 2014 | 9,177 | 11,616 | – | 20,793 | 1,330 | 87,649 | 1,709 | 37,016 |
| Acquisitions | – | – | – | – | – | – | – | – |
| Dispositions | (4,253) | (3) | – | (4,256) | (336) | (14,382) | – | (6,988) |
| Discoveries | – | – | – | – | – | – | – | – |
| Extensions and Improved Recovery | 41 | 564 | – | 605 | 5 | 519 | – | 697 |
| Economic Factors | 120 | 450 | – | 570 | (58) | (2,777) | (16) | 46 |
| Technical Revisions | (1,719) | (2,824) | – | (4,543) | 8 | (17,207) | (164) | (7,430) |
| Production | – | – | – | – | – | – | – | – |
| **Probable Reserves at December 31, 2015** | 3,367 | 9,804 | – | 13,171 | 949 | 53,802 | 1,530 | 23,342 |

| UNITED STATES | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Tight Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Conventional Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|---|
| Probable Reserves at December 31, 2014 | – | – | 52,631 | 52,631 | 3,332 | – | 310,720 | 107,749 |
| Acquisitions | – | – | – | – | – | – | – | – |
| Dispositions | – | – | (126) | (126) | (8) | – | (63) | (144) |
| Discoveries | – | – | – | – | – | – | – | – |
| Extensions and Improved Recovery | – | – | 7,616 | 7,616 | 680 | – | 43,650 | 15,571 |
| Economic Factors | – | – | 86 | 86 | 15 | – | 2,621 | 538 |
| Technical Revisions | – | – | (15,156) | (15,156) | 25 | – | (20,170) | (18,492) |
| Production | – | – | – | – | – | – | – | – |
| **Probable Reserves at December 31, 2015** | – | – | 45,051 | 45,051 | 4,044 | – | 336,758 | 105,221 |

| TOTAL ENERPLUS | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Tight Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Conventional Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|---|
| Probable Reserves at December 31, 2014 | 9,177 | 11,616 | 52,631 | 73,424 | 4,662 | 87,649 | 312,429 | 144,768 |
| Acquisitions | – | – | – | – | – | – | – | – |
| Dispositions | (4,253) | (3) | (126) | (4,382) | (344) | (14,382) | (63) | (7,132) |
| Discoveries | – | – | – | – | – | – | – | – |
| Extensions and Improved Recovery | 41 | 564 | 7,616 | 8,221 | 685 | 519 | 43,650 | 16,268 |
| Economic Factors | 120 | 450 | 86 | 656 | (43) | (2,777) | 2,606 | 584 |
| Technical Revisions | (1,719) | (2,824) | (15,156) | (19,699) | 33 | (17,207) | (20,334) | (25,923) |
| Production | – | – | – | – | – | – | – | – |
| **Probable Reserves at December 31, 2015** | 3,367 | 9,804 | 45,051 | 58,222 | 4,993 | 53,802 | 338,287 | 128,563 |

PROVED PLUS PROBABLE RESERVES – GROSS VOLUMES (FORECAST PRICES)

| CANADA | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Tight Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Conventional Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|---|
| Proved Plus Probable Reserves at December 31, 2014 | 35,748 | 43,138 | – | 78,886 | 5,662 | 353,247 | 6,773 | 144,552 |
| Acquisitions | – | – | – | – | – | – | – | – |
| Dispositions | (16,436) | (9) | – | (16,445) | (1,180) | (51,520) | – | (26,212) |
| Discoveries | – | – | – | – | – | – | – | – |
| Extensions and Improved Recovery | 141 | 1,977 | – | 2,118 | 21 | 2,057 | – | 2,482 |
| Economic Factors | (109) | (1,317) | – | (1,426) | (252) | (26,080) | (48) | (6,033) |
| Technical Revisions | 263 | 868 | – | 1,131 | 633 | 7,097 | (644) | 2,840 |
| Production | (2,370) | (3,148) | – | (5,518) | (661) | (47,435) | (402) | (14,151) |
| **Proved Plus Probable Reserves at December 31, 2015** | 17,238 | 41,508 | – | 58,746 | 4,223 | 237,366 | 5,678 | 103,477 |

| UNITED STATES | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Tight Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Conventional Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|---|
| Proved Plus Probable Reserves at December 31, 2014 | – | – | 121,545 | 121,545 | 7,136 | – | 936,350 | 284,739 |
| Acquisitions | – | – | – | – | – | – | – | – |
| Dispositions | – | – | (439) | (439) | (24) | – | (211) | (499) |
| Discoveries | – | – | – | – | – | – | – | – |
| Extensions and Improved Recovery | – | – | 13,210 | 13,210 | 1,149 | – | 67,044 | 25,532 |
| Economic Factors | – | – | (1,087) | (1,087) | (80) | – | (4,100) | (1,850) |
| Technical Revisions | – | – | 7,647 | 7,647 | 4,300 | – | 40,216 | 18,650 |
| Production | – | – | (9,623) | (9,623) | (1,007) | – | (81,609) | (24,231) |
| **Proved Plus Probable Reserves at December 31, 2015** | – | – | 131,253 | 131,253 | 11,474 | – | 957,690 | 302,341 |

| TOTAL ENERPLUS | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Tight Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Conventional Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|---|
| Proved Plus Probable Reserves at December 31, 2014 | 35,748 | 43,138 | 121,545 | 200,431 | 12,798 | 353,247 | 943,123 | 429,291 |
| Acquisitions | – | – | – | – | – | – | – | – |
| Dispositions | (16,436) | (9) | (439) | (16,884) | (1,205) | (51,520) | (211) | (26,710) |
| Discoveries | – | – | – | – | – | – | – | – |
| Extensions and Improved Recovery | 141 | 1,977 | 13,210 | 15,328 | 1,170 | 2,057 | 67,044 | 28,014 |
| Economic Factors | (109) | (1,317) | (1,087) | (2,513) | (332) | (26,080) | (4,148) | (7,883) |
| Technical Revisions | 263 | 868 | 7,647 | 8,778 | 4,933 | 7,097 | 39,572 | 21,489 |
| Production | (2,370) | (3,148) | (9,623) | (15,141) | (1,667) | (47,435) | (82,011) | (38,382) |
| **Proved Plus Probable Reserves at December 31, 2015** | 17,238 | 41,508 | 131,253 | 189,999 | 15,697 | 237,366 | 963,368 | 405,818 |

## FUTURE DEVELOPMENT COSTS

Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect the evaluators' best estimate of the capital required to bring the proved and proved plus probable reserves on production. The aggregate of the exploration and development costs incurred in the most recent year and the change during the year in estimated future development capital generally reflect the total finding and development costs related to reserves additions for that year.

Although estimated development costs per well decreased substantially in the U.S., this was offset by the change in the estimated US/CDN exchange rate.

The following is a summary of the independent reserves evaluators' estimated FDC required to bring the total proved and proved plus probable reserves on production:

| | CANADA | | | | UNITED STATES | | | |
|---|---|---|---|---|---|---|---|---|
| | Proved Reserves | | Proved Plus Probable Reserves | | Proved Reserves | | Proved Plus Probable Reserves | |
| Year (in $ millions) | Undiscounted | Discounted at 10%/year | Undiscounted | Discounted at 10%/year | Undiscounted | Discounted at 10%/year | Undiscounted | Discounted at 10%/year |
| 2016 | 46 | 45 | 49 | 48 | 275 | 267 | 302 | 293 |
| 2017 | 86 | 75 | 89 | 77 | 323 | 280 | 362 | 314 |
| 2018 | 30 | 24 | 42 | 34 | 328 | 259 | 437 | 345 |
| 2019 | 24 | 18 | 29 | 21 | – | – | 266 | 191 |
| 2020 | 8 | 5 | 9 | 6 | – | – | 113 | 76 |
| Remainder | 25 | 13 | 25 | 13 | – | – | – | – |
| **Total** | 219 | 180 | 243 | 199 | 926 | 806 | 1,480 | 1,218 |

## F&D AND FD&A COSTS – including future development capital

| ($ millions except for per BOE amounts) | 2015 | 2014 | 2013 | 3 Year |
|---|---|---|---|---|
| **Proved Plus Probable Reserves** | | | | |
| **Finding & Development Costs** | | | | |
| Capital Expenditures | $ 493.4 | $ 811.0 | $ 681.4 | $ 1,985.9 |
| Net change in Future Development Costs | $ (142.2) | $ (71.3) | $ 200.0 | $ (13.5) |
| Gross Reserves additions (MMBOE) | 41.6 | 75.5 | 78.1 | 195.3 |
| F&D costs ($/BOE) | $ 8.44 | $ 9.80 | $ 11.28 | $ 10.10 |
| **Finding, Development & Acquisition Costs** | | | | |
| Capital expenditures and net acquisitions | $ 216.2 | $ 625.9 | $ 561.1 | $ 1,403.3 |
| Net change in Future Development Costs | $ (212.5) | $ (59.2) | $ 216.6 | $ (55.2) |
| Gross Reserves additions (MMBOE) | 14.9 | 65.8 | 93.0 | 173.7 |
| FD&A costs ($/BOE) | $ 0.25 | $ 8.62 | $ 8.36 | $ 7.76 |
| **Proved Reserves** | | | | |
| **Finding & Development Costs** | | | | |
| Capital Expenditures | $ 493.4 | $ 811.0 | $ 681.4 | $ 1,985.9 |
| Net change in Future Development Costs | $ 210.0 | $ 13.8 | $ (106.4) | $ 117.4 |
| Gross Reserves additions (MMBOE) | 50.7 | 69.1 | 57.1 | 176.9 |
| F&D costs ($/BOE) | $ 13.88 | $ 11.94 | $ 10.08 | $ 11.89 |
| **Finding, Development & Acquisition Costs** | | | | |
| Capital expenditures and net acquisitions | $ 216.2 | $ 625.9 | $ 561.1 | $ 1,403.3 |
| Net change in Future Development Costs | $ 139.7 | $ 4.9 | $ (112.8) | $ 31.8 |
| Gross Reserves additions (MMBOE) | 31.1 | 60.9 | 69.9 | 161.9 |
| FD&A costs ($/BOE) | $ 11.44 | $ 10.36 | $ 6.41 | $ 8.86 |

## CONTINGENT RESOURCES ASSESSMENT

The following table provides a breakdown of the economic, best estimate economic contingent resources associated with a portion of our Fort Berthold, Marcellus, Wilrich and Canadian waterflood assets as at December 31, 2015. These contingent resources are economic using McDaniel's January 1, 2016 forecast commodity prices, use established technologies and are all classified in the "development pending" maturity sub-class.

The evaluations of contingent resources associated with the Wilrich, a portion of our waterflood properties and our leases at Fort Berthold were conducted by Enerplus and audited by McDaniel. NSAI evaluated 100% of our Marcellus shale gas assets in the U.S., including the estimate of contingent resources. There is uncertainty that it will be commercially viable to produce any portion of the resources.

Please see Enerplus' Annual Information Form ("**AIF**") – Appendix A for additional disclsoures related to our contingent resources as at December 31, 2015. The AIF is available at www.enerplus.com as well as on the Company's SEDAR profile at www.sedar.com.

| Development Pending Contingent Resources | Unrisked "Best Estimate" Contingent Resources | Contingent Resources Net Drilling Locations |
|---|---|---|
| **Canadian Properties** | | |
| Waterfloods – IOR/EOR on a portion of waterfloods (MMBOE) | 34.7 | 62.9 |
| Wilrich – Conventional natural gas (BcfGE) | 319.7 | 66.3 |
| **Total Canada (MMBOE)** | **88.0** | **129.1** |
| **United States Properties** | | |
| Fort Berthold – Bakken/Three Forks Tight Oil (MMBOE) | 96.9 | 152.2 |
| Marcellus – Shale gas (Bcf) | 803.1 | 95.0 |
| **Total United States (MMBOE)** | **230.7** | **247.2** |
| **Total Company (MMBOE)** | **318.7** | **376.3** |

## NET PRESENT VALUE OF FUTURE PRODUCTION REVENUE

The following table provides an estimate of the net present value of Enerplus' future production revenue after deduction of royalties, estimated future capital and operating expenditures, before income taxes. It should not be assumed that the present value of estimated future cash flows shown below is representative of the fair market value of the reserves.

The forecast price assumptions reflect a reduction in the forecast prices for both our portfolio of crude oil and natural gas at AECO and Henry Hub when compared to the price assumptions used at December 31, 2014. The 5% decrease in our 2P reserves at December 31, 2015 resulted in the estimated before tax NPV, using a 10% discount rate, to decrease by 21%.

### Net Present Value of Future Production Revenue – Forecast Prices and Costs (before tax)

| **Reserves at December 31, 2015,** ($ Millions, discounted at) | 0% | 5% | 10% | 15% |
|---|---|---|---|---|
| Proved developed producing | $ 4,116 | $ 2,759 | $ 2,051 | $ 1,634 |
| Proved developed non-producing | 151 | 64 | 26 | 6 |
| Proved undeveloped | 1,314 | 573 | 233 | 55 |
| **Total Proved** | $ 5,580 | $ 3,397 | $ 2,310 | $ 1,695 |
| Probable | 3,879 | 1,938 | 1,153 | 773 |
| **Total Proved Plus Probable Reserves (before tax)** | $ 9,459 | $ 5,335 | $ 3,463 | $ 2,468 |

## NET ASSET VALUE

Enerplus' estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before taxes, as estimated by our independent reserves engineers, McDaniel and NSAI, at year-end, plus the estimated value of our undeveloped acreage and other equity investments, less decommissioning liabilities, long-term debt and net working capital. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserves engineers.

In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserves reports with no further acquisitions or incremental development, including development of contingent resources. At December 31, 2015, the best estimate of economic contingent resources contained within our leases was 318.8 million BOE, unrisked. As we execute our capital programs, we expect to convert contingent resources to reserves which could result in a significant increase in our booked proved plus probable reserves. The land values described in the Net Asset Value table below do not necessarily reflect the full value of the contingent resources associated with these lands.

### Net Asset Value (Forecast Prices and Costs at December 31, 2015)

| ($ millions except share amounts, discounted at) | 0% | 5% | 10% | 15% |
|---|---|---|---|---|
| Total net present value of proved plus probable reserves (before tax) | $9,459 | $5,335 | $3,463 | $2,468 |
| Undeveloped acreage (2015 Year End)(1) | 268 | 268 | 268 | 268 |
| Asset retirement obligations(4) | (206) | (165) | (70) | (38) |
| Long-term debt, including current portion (net of cash) | (1,217) | (1,217) | (1,217) | (1,217) |
| Net working capital(2) | (37) | (37) | (37) | (37) |
| Net Asset Value | **$8,267** | **$4,184** | **$2,407** | **$1,444** |
| Net Asset Value per Share(3) | **$40.03** | **$20.26** | **$11.65** | **$6.99** |

(1) Canadian acreage in Stacked Mannville is carried at market price; validated Duvernay acreage is carried at acquisition cost. Prospective acreage in the U.S. is carried at historical acquisition cost. All other acreage is valued at a nominal value of $50/acre. U.S. values were converted to Canadian dollars using a US/CDN exchange rate of 1.3840.

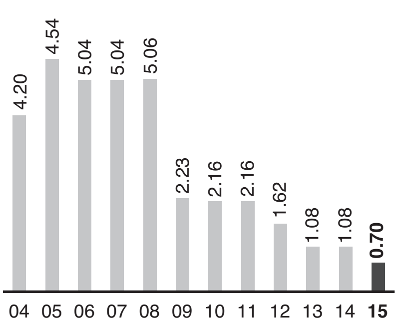
(2) Net working capital includes deferred income tax assets and deferred financial assets and credits.

(3) Based on 206,539,000 shares outstanding as at December 31, 2015.

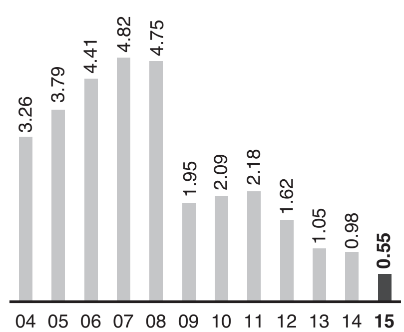
(4) Asset retirement obligations ("ARO") may not equal the balance sheet as a portion of ARO costs are already reflected in the present value of 2P reserves, and the discount rates applied may differ.

### CASH DIVIDENDS PAID TO SHAREHOLDERS*

Cash Dividends Paid to Shareholders – CDN$
*(Cdn$/Share)*




Cash Dividends Paid to Shareholders – US$
*(US$/Share)*




* paid January – December.

Amounts paid to U.S. investors are converted to U.S. dollars on the applicable payment date. Amounts shown are prior to any amounts deducted for Canadian withholding tax.

# 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

**BcfGE**(1) billion cubic feet of gas equivalent

**BOE**(1) barrels of oil equivalent

**Brent** crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $US dollars.

**F&D Costs** finding and development costs

**FD&A Costs** finding, development and acquisition costs

**FDC** future development capital

**IFRS** International Financial Reporting Standards

**Mbbls** thousand barrels

**MBOE** thousand barrels of oil equivalent

**Mcf** thousand cubic feet

**MMbbl(s)** million barrels

**MMBOE** million barrels of oil equivalent

**MMBtu** million British Thermal Units

**MMcf** million cubic feet

**MWh** megawatt hour(s) of electricity

**NGLs** natural gas liquids

**NI 51-101** National Instrument 51-101 Oil and Gas Activities adopted by the Canadian Securities regulatory Authorities (pertaining to reserves reporting in Canada)

**NYMEX** New York Mercantile Exchange, the benchmark for North American natural gas pricing

**2P Reserves** proved plus probable reserves

**RLI** reserves life index

**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

(1) The Corporation has adopted the standard of 6 Mcf of natural gas: 1 bbl of oil when converting natural gas to BOEs, MBOEs and MMBOEs, and 1 bbl of oil and NGLs: 6 Mcf of natural gas when converting oil and NGLs to BcfGEs. For further information, see "*Presentation of Oil and Gas Reserves, Resources and Production Information – Barrels of Oil and Cubic Feet of Gas Equivalent*".

# DEFINITIONS

**Adjusted Payout Ratio** Calculated as the sum of dividends to shareholders (net of stock dividends and DRIP proceeds) plus capital spending (including office capital) divided by funds flow.

**Contingent Resources** Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early project stage. "Economic" contingent resources are those resources that are economically recoverable based on McDaniel's January 1, 2016 forecast prices.

The economic contingent resources estimates in this Appendix A are presented as the "best estimate" of the quantity that will actually be recovered, meaning that it is equally likely that the actual remaining quantities recovered will be greater or less than the "best estimate", and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the "best estimate".

**Contingent Resources, Development Pending** This contingent resources sub-class is assigned to contingent resources for a particular project where resolution of the final conditions for development is being actively pursued (there is a high chance of development) and the project is expected to be developed in a reasonable timeframe.

**BOE** Barrels of oil equivalent converting 6 Mcf of natural gas to one barrel of oil equivalent and one barrel of natural gas liquids to one barrel of oil equivalent. The factor used to convert natural gas and natural gas liquids to oil equivalent is not based on either energy content or prices but is a commonly used industry benchmark. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas 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.

**F&D Costs** Finding and development costs. It is a measure of the effectiveness of a company's capital program. F&D costs presented are calculated (i) in the case of F&D costs for proved reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves in the year, and (ii) in the case of F&D costs for proved plus probable reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding and development costs related to its reserves additions for that year.

**FD&A Costs** Finding, development and acquisition costs. It is a measure of a company's ability to add resereves in a cost effective manner. FD&A costs presented are calculated (i) in the case of FD&A costs for proved reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves including net acquisitions in the year, and (ii) in the case of FD&A costs for proved plus probable reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves including net acquisitions in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding, development and acquisition costs related to its reserves additions for that year.

**Future Development Costs (FDC)** Future Development Costs is defined as those costs which reflect the independent evaluator's best estimate of what it will cost to bring the proved and probable non-producing and undeveloped reserves on production in the future. Changes to this figure occur annually as a result of development activities, acquisition and disposition activities, additions to non-producing and undeveloped reserves and capital cost estimate revisions.

**NGLs** Natural gas liquids – hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

**Oil, Heavy** Oil with a density between 10 to 22.3 degrees API or where a royalty regime exists specific to heavy oil, it is defined based upon that royalty regime.

**Oil, Light & Medium** Oil that has a density of 22.3 degrees API or higher.

**Oil, Tight** Oil that is petroleum that consists of light crude oil contained in petroleum-bearing formations of low permeability, often shale or tight sandstone.

**Operating Income** Calculated as revenues from oil and gas sales less cash hedging costs, transportation costs, royalties and operating costs.

**Production, Company Interest** Our working interest (operated and non-operated) share of production before the deduction of royalties, but inclusive of any royalty interest production owned by Enerplus. Therefore, the "company interest" production of the Corporation may not be comparable to similar measures presented by other issuers, and investors are cautioned that "company interest" production should not be construed as an alternative to "gross" or "net" production calculated in accordance with NI 51-101.

**Production, Gross** Our working interest (operated and non-operated) share of production before the deduction of any royalty interest production. Unless otherwise stated, all production volumes utilized in any discussions or calculations are gross production volumes.

**Production, Proved** Proved production volumes as determined by the independent reserves engineering report for 2003 and forward, and management's estimate for all prior years.

**Reserves Life Index, Proved** Calculated as proved reserves at year-end divided by the following year's estimated proved production volumes as determined by the independent reserves engineering report.

**Reserves Life Index, Proved plus Probable** Calculated as proved plus probable reserves at year-end divided by the following year's estimated proved plus probable production volumes as determined by the independent reserves engineering report.

**Reserves, Gross** Our working interest (operated and non-operated) share of reserves before the deduction of any royalty interest reserves but exclusive of royalty interest reserves owned by Enerplus.

**Reserves, Net** Our working interest (operated and non-operated) share of reserves after the deduction of royalty interest reserves but inclusive of any royalty interest reserves owned by Enerplus.

**Reserves, Probable** Additional reserves, calculated in accordance with NI 51-101, that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

**Reserves, Proved** Reserves that can be estimated with a high degree of certainty to be recoverable in accordance with NI 51-101. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

**Reserves, Developed Non-Producing** Reserves that have either not been on production or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

**Reserves, Developed Producing** Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

**Reserves, Undeveloped** Reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production.

**Total Return** Calculated using the change in the share price from the start of the period (including any capital appreciation or depreciation) and the total cash dividends paid during the period divided by the starting share price.

# BOARD OF DIRECTORS

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

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

**Michael R. Culbert**(3)(9)
President & Chief Executive Officer
Progress Energy Canada Ltd.
Calgary, Alberta

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

**Hilary A. Foulkes**(5)(9)(11)
Corporate Director
Calgary, Alberta

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

**Susan M. MacKenzie**(7)(10)
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

**Ray J. Daniels**
Senior Vice President, Operations

**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, Enerplus (USA) Corporation

**Lisa M. Ower**
Vice President, People & Culture

**Shaina B. Morihira**
Corporate Controller

(1) Mr. Kenneth Young resigned his duties as Vice President, Land & Operations Services effective February 10, 2016. John Hoffman, Vice President, Canadian Operations now has oversight of Land and Operations Services.

# 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 Reserves 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**
U.S. Bank Tower
Suite 2200, 950 17th Street
Denver, Colorado 80202-2805

Telephone: 720.279.5500
Fax: 720.279.5550

**Annual General Meeting**
Shareholders are encouraged to attend the Annual General Meeting being held on:

Friday, May 6, 2016
10:00 am, MT
The Telus Convention Centre
Glen 206
120 – 9th Avenue SE
Calgary, Alberta

Enerplus Corporation is a responsible developer of high quality crude oil and natural gas assets in Canada and the United States, focused on providing both growth and income to its shareholders.

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ERF LISTED ON TMX Toronto Stock Exchange

ERF LISTED NYSE