enerPLUS

2014 FINANCIAL SUMMARY

In 2014, we continued to build on our track record of strong operational performance.

13% Growth in annual average production per share

12% Increase in funds flow per share

6% Growth in 2P reserves per share

175% Production replacement

Contents

2014 FINANCIAL SUMMARY

Selected Financial and Operating Results

SELECTED FINANCIAL RESULTS	Three months ended December 31, 2014	Three months ended December 31, 2013	Twelve months ended December 31, 2014	Twelve months ended December 31, 2013
Financial (000's)				
Funds Flow	$ 212,518	$ 180,741	$ 859,020	$ 754,233
Cash and Stock Dividends	55,511	54,665	221,098	216,864
Net Income	151,652	29,626	299,076	47,976
Debt Outstanding – net of cash	1,134,894	1,022,308	1,134,894	1,022,308
Capital Spending	180,999	223,035	811,026	681,437
Property and Land Acquisitions	1,305	173,387	18,491	244,837
Property Divestments	17,945	168,050	203,576	365,135
Debt to Trailing 12 Month Funds Flow	1.3x	1.4x	1.3x	1.4x
Financial per Weighted Average Shares Outstanding				
Funds Flow	$ 1.03	$ 0.89	$ 4.20	$ 3.76
Net Income (Basic)	0.74	0.15	1.46	0.24
Weighted Average Number of Shares Outstanding (000's)	205,519	202,257	204,510	200,567
Selected Financial Results per BOE(1)(2)				
Oil & Natural Gas Sales(3)	$ 38.83	$ 43.79	$ 47.61	$ 48.11
Royalties and Production Taxes	(9.13)	(9.53)	(10.75)	(10.21)
Commodity Derivative Instruments	4.71	1.90	0.09	0.81
Operating Costs	(10.75)	(10.46)	(10.40)	(10.50)
General and Administrative	(2.62)	(2.28)	(2.22)	(2.54)
Share Based Compensation (Expense)/Recoveries	1.40	(1.06)	0.03	(0.71)
Interest, Foreign Exchange and Other Expenses	(1.23)	(1.51)	(1.42)	(1.71)
Taxes	0.67	0.01	(0.12)	(0.24)
Funds Flow	$ 21.88	$ 20.86	$ 22.82	$ 23.01

SELECTED OPERATING RESULTS	Three months ended December 31, 2014	Three months ended December 31, 2013	Twelve months ended December 31, 2014	Twelve months ended December 31, 2013
Average Daily Production(2)				
Crude oil (bbls/day)	42,818	37,731	40,208	38,250
NGLs (bbls/day)	3,487	3,813	3,565	3,472
Natural gas (Mcf/day)	355,709	315,739	356,142	288,423
Total (BOE/day)	105,591	94,167	103,130	89,793
% Crude Oil & Natural Gas Liquids	44%	44%	42%	46%
Average Selling Price(2)(3)				
Crude oil (per bbl)	$ 67.13	$ 77.77	$ 84.53	$ 83.99
NGLs (per bbl)	40.36	54.26	49.89	52.25
Natural gas (per Mcf)	3.12	3.26	3.81	3.26
Net Wells drilled	25	18	88	62

(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) Net of transportation costs, but before royalties and the effects of commodity derivative instruments.

Average Benchmark Pricing	Three months ended December 31, 2014	Three months ended December 31, 2013	Twelve months ended December 31, 2014	Twelve months ended December 31, 2013
WTI crude oil (US$/bbl)	$ 73.15	$ 97.46	$ 93.00	$ 97.97
AECO – monthly index (CDN$/Mcf)	4.01	3.16	4.42	3.16
AECO – daily index (CDN$/Mcf)	3.60	3.53	4.51	3.17
NYMEX – last day (US$/Mcf)	4.00	3.60	4.41	3.65
USD/CDN exchange rate	1.14	1.05	1.10	1.03

Share Trading Summary For the twelve months ended December 31, 2014	CDN* – ERF (CDN$)	U.S.** – ERF (US$)
High	27.05	25.37
Low	9.02	7.75
Close	11.19	9.60

* TSX and other Canadian trading data combined.

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

2014 Dividends per Share	CDN$	US$(1)
First Quarter Total	$ 0.27	$ 0.24
Second Quarter Total	$ 0.27	$ 0.25
Third Quarter Total	$ 0.27	$ 0.25
Fourth Quarter Total	$ 0.27	$ 0.24
Total Year-to-Date	$ 1.08	$ 0.98

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

2014 HIGHLIGHTS

Reserves/Resources

We delivered strong reserves/resources results in 2014:

- Proved plus probable ("2P") reserves grew by 7% to 429 MMBOE (50% oil and liquids). On a per share basis, 2P reserves increased by 6% year-over-year.
- Proved ("1P") reserves grew by 9% to 285 MMBOE, representing 66% of 2P reserves. Proved producing reserves represent 74% of total 1P reserves.
- 75 MMBOE of 2P reserves were added through our capital spending program replacing over 200% of 2014 annual production. Well performance in both North Dakota and the Marcellus continued to exceed the previous forecasts of our independent reserves engineers and resulted in significant positive technical revisions. Approximately 30% of additions were from crude oil and 70% from natural gas.
- 2P finding and development ("F&D") costs including future development capital ("FDC") continued to improve, decreasing by 13% to $9.80 per BOE. This represents a recycle ratio of 2.7 times based on our operating netback of $26.46 per BOE, before hedging, in 2014.
- We sold various interests in non-core properties representing 11 MMBOE of 2P reserves at a value of $19.65 per BOE. Total 2P reserves additions, net of our divestment activities, were approximately 66 MMBOE, replacing 175% of 2014 annual production.
- 2P finding, development and acquisition ("FD&A") costs per BOE were $8.62 including FDC, relatively unchanged from 2013. On a three-year basis, 2P FD&A costs, including FDC, continued to improve, declining by 17% to $12.13 per BOE.
- 2P reserves in Fort Berthold, North Dakota increased 16%, including positive technical revisions, to 123 MMBOE, replacing over 300% of 2014 production at an attractive F&D cost of $16.87 per BOE. Based upon an average operating netback of $47.10 per BOE in 2014, this represents a 2.8x recycle ratio.
- 2P reserves attributable to our Marcellus shale gas assets increased 40%, including positive technical revisions, to 840 Bcf, replacing approximately 450% of 2014 production at a low F&D cost of approximately $0.50 per Mcf. With an average operating netback of $1.78 per Mcf in 2014, this represents a 3.6x recycle ratio.
- Canadian reserves were impacted by the sale of non-core properties. 2P additions were offset by dispositions and deletions of undeveloped locations resulting in an overall decrease of 15% year-over-year to 145 MMBOE.
- Economic best estimate contingent resources, within a portion of our portfolio, increased by 86 MMBOE from year-end 2013, to 449 MMBOE. This represents approximately 13 years of organic reserves replacement potential based on our 2015 forecast production volumes.
- Our 2P reserve life index remains virtually unchanged from 2013 at 10.7 years.

Operations

- We delivered annual production growth of 15% in 2014 (13% per share). Having increased our production guidance twice during 2014, we achieved our target of 102,000 – 104,000 BOE per day with daily production averaging 103,130 BOE. This is despite the sale of 3,500 BOE per day of non-core production and significant natural gas production curtailment in the Marcellus.
- Total average liquids production increased by 5% in 2014 to approximately 43,800 BOE per day representing 42% of our production mix in 2014. We continued to see significant increases in crude oil production from our properties in Fort Berthold, growing production by over 30% in 2014.
- Natural gas production increased by 23% to average 356 MMcf per day for the year, representing 58% of Enerplus' production mix. This growth was due to the acquisition of additional working interests in the Marcellus in the fourth quarter of 2013, and the success of our Marcellus development program throughout the year which resulted in a doubling of production, from 95 MMcf per day in 2013 to approximately 188 MMcf per day in 2014.
- Despite the growth in natural gas production, approximately 5,000 BOE per day of natural gas from the Marcellus was curtailed during the second half of 2014. These curtailments were driven by a strategy to restrict sales and maximize value by delaying production until natural gas prices improve in northeast Pennsylvania.
- We continued to focus our portfolio in 2014 and concentrate on our core areas. We divested $204 million of non-core assets comprised of natural gas properties in the Deep Basin with production of approximately 3,100 BOE per day, the sale of our gross over-riding royalty interests at Jonah in Wyoming (400 BOE per day) and the balance of proceeds from the sale of our undeveloped Montney acreage in 2013. We redeployed a portion of the proceeds into our core areas through the acquisition of undeveloped land in the Deep Basin in Canada, in the

Marcellus in Pennsylvania, and in Fort Berthold, North Dakota. Our acquisition and divestment activities realized net proceeds of $185 million in 2014.

Financial

- Funds flow grew by 14% year-over-year to $859 million driven by the increase in production volumes and higher average realized commodity prices. On a per share basis, this was a 12% increase.
- Net income increased to $299 million from $48 million in 2013 as a result of an increase in crude oil and natural gas sales and commodity hedging gains.
- Capital spending came in slightly lower than our guidance of $830 million, totaling $811 million. We invested 85% of our budget on drilling and completion activities, with 88 net wells drilled and 68 brought on-stream across our asset base. Approximately 65% of our spending was directed to our crude oil assets with the majority invested at Fort Berthold, North Dakota.
- We maintained strong capital efficiencies in 2014, despite production curtailments in the Marcellus. Based upon our capital spending and the growth in production volumes from the fourth quarter of 2013 to the same period in 2014 (including curtailment), this reflects a capital efficiency of approximately $22,500 per daily BOE.
- Operating costs were $10.43 per BOE, down slightly from $10.48 per BOE in 2013, though above our guidance target of $10.25 per BOE primarily due to production curtailments of approximately 5,000 BOE per day at our lower operating cost Marcellus properties in the second half of 2014. Cash G&A decreased 13% to $2.22 per BOE, down from $2.54 per BOE in 2013. The weakening Canadian dollar also impacted both our U.S. operating and G&A costs.
- Our adjusted payout ratio was 118% in 2014 compared to 114% in 2013 as we saw a proportionately larger increase in our capital spending program as we elected to redeploy a portion of the proceeds from our non-core asset sales into our core assets. In addition, participation in our Stock Dividend Program ("SDP") decreased as we suspended the SDP in September 2014 to eliminate dilution. After adjusting for net acquisition and divestment proceeds, our adjusted payout ratio decreased to 97% in 2014.
- As a result of the growth in funds flow and the net proceeds from our divestment activities, our trailing twelve month debt-to-funds flow ratio decreased to 1.3 times at year-end, down from 1.4 times at year-end 2013. Less than 10% of our $1.0 billion bank credit facility was drawn at year-end.

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

The following discussion and analysis of financial results is dated February 19, 2015 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, 2014 and 2013 and for the years ended December 31, 2014, 2013 and 2012.

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 on this basis to remain comparable with our peers.

The following table provides a reconciliation of our production volumes.

	Years ended December 31,		
Average Daily Production Volumes	**2014**	**2013**	**2012**
Company interest production volumes			
Crude oil (bbls/day)	40,208	38,250	36,509
Natural gas liquids (bbls/day)	3,565	3,472	3,627
Natural gas (Mcf/day)	356,142	288,423	251,773
Company interest production volumes (BOE/day)	103,130	89,793	82,098
Royalty volumes			
Crude oil (bbls/day)	7,731	6,938	6,315
Natural gas liquids (bbls/day)	775	802	837
Natural gas (Mcf/day)	55,114	42,192	30,294
Royalty volumes (BOE/day)	17,692	14,772	12,201
Net production volumes			
Crude oil (bbls/day)	32,477	31,312	30,194
Natural gas liquids (bbls/day)	2,790	2,670	2,790
Natural gas (Mcf/day)	301,028	246,231	221,479
Net production volumes (BOE/day)	85,438	75,021	69,897

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, transportation and cash operating costs.

Calculation of Netback

($ millions)	Years ended December 31, 2014	2013	2012
Oil and natural gas sales	$ 1,849.3	$ 1,616.8	$ 1,365.5
Less:			
Royalties	(323.1)	(264.3)	(212.2)
Production taxes	(81.5)	(70.4)	(56.6)
Transportation	(57.2)	(39.9)	(26.6)
Cash operating costs(1)	(391.3)	(344.2)	(315.8)
Netback before hedging	996.2	$ 898.0	754.3
Cash gains	3.5	26.6	18.4
Netback after hedging	$ 999.7	$ 924.6	$ 772.7

(1) Operating costs adjusted to exclude non-cash losses on fixed price electricity swaps of $1.3 million in 2014, non-cash gains of $0.8 million in 2013 and non-cash losses of $3.2 million in 2012.

"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 provided by 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, 2014	2013	2012
Cash flow from operating activities	$ 787.2	$ 766.5	$ 535.7
Asset retirement obligation expenditures	19.4	16.6	19.9
Changes in non-cash operating working capital	52.4	(28.9)	88.9
Funds flow	$ 859.0	$ 754.2	$ 644.5

"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.

"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, 2014	2013	2012
Cash dividends(1)	$ 199.3	$ 170.7	$ 258.7
Capital and office expenditures	818.0	687.9	865.3
	$ 1,017.3	$ 858.6	$ 1,124.0
Funds flow	$ 859.0	$ 754.2	$ 644.5
Adjusted payout ratio (%)	118%	114%	174%

(1) Cash dividends exclude Stock Dividend Plan proceeds in 2014 and 2013 and former Dividend Reinvestment Plan proceeds in 2012.

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

2014 FOURTH QUARTER OVERVIEW

Production levels averaged 105,591 BOE/day in the fourth quarter, up from 104,035 BOE/day in the third quarter. We continued to curtail production on our Marcellus properties in response to low realized prices in the Northeast Pennsylvania region. The curtailments represent additional production capacity of wells that have been drilled, completed, tied-in and brought on production previously, but are being temporarily restrained. For the fourth quarter, production curtailments averaged 6,000 – 7,000 BOE/day compared to 3,000 – 4,000 BOE/day in the third quarter of 2014. Despite these curtailments, natural gas production remained relatively constant, decreasing by only 1% compared to the third quarter. Oil and liquids production was strong, increasing by 6% or approximately 2,500 BOE/day in the quarter.

Funds flow for the quarter was $212.5 million, consistent with the prior quarter and an increase of 18% over the same period in 2013. Despite the growth in production, the sharp decline in commodity prices led to a decrease in oil and natural gas revenue compared to the third quarter which was partially offset by cash gains on commodity hedges.

SUMMARY FOURTH QUARTER INFORMATION

In comparing the fourth quarter of 2014 with the same period in 2013:

- Average daily production was 105,591 BOE/day compared to 94,167 BOE/day in 2013. Production growth was primarily due to higher volumes from our Marcellus natural gas properties and our Fort Berthold crude oil properties, which had year-over-year production increases of approximately 51% and 38%, respectively. This growth was achieved despite the fourth quarter price related curtailments in the Marcellus of 6,000 – 7,000 BOE/day and the divestment of non-core Canadian natural gas properties.
- Capital spending decreased to $181.0 million compared to $223.0 million in 2013 as spending slowed in response to the significant decline in crude oil prices during the fourth quarter. Investment was focused in our core areas, with spending of $26.5 million in the Marcellus, $89.8 million in Fort Berthold and $47.5 million on our Canadian crude oil waterflood properties.
- Net income increased to $151.7 million from $29.6 million due primarily to non-cash mark-to-market gains on our commodity derivatives of $174.0 million compared to non-cash losses of $6.3 million during the same period in 2013.
- Funds flow totaled $212.5 million, an increase of $31.8 million or 18% over the same period in 2013. Oil and natural gas revenue was similar to 2013, with the increase in production levels offsetting an overall decline in commodity prices.
- We realized cash hedging gains of $45.8 million in the quarter on our commodity derivatives, compared to $16.5 million in the fourth quarter of 2013.
- Cash general and administrative ("G&A") expenses were $2.62/BOE compared to $2.28/BOE in 2013 mainly due to one-time compensation charges in the fourth quarter of 2014.
- Cash share based compensation expense decreased to a recovery of $1.40/BOE compared to an expense of $1.06/BOE in 2013 due to the decrease in our share price during the fourth quarter of 2014.
- In early November, we closed the sale of non-core Canadian natural gas properties with production of approximately 1,200 BOE/day for proceeds of $20.9 million after closing adjustments. In the fourth quarter of 2013, we sold the first half of our undeveloped Montney acreage and additional non-core Canadian oil properties for aggregate proceeds of $168.0 million.
- There was no acquisition activity during the fourth quarter of 2014. During the same period in 2013, property and land acquisitions totaled $173.4 million, including the purchase additional working interest in our core Marcellus properties for $157.9 million, representing approximately 42 MMcf/day of production.

SELECTED FOURTH QUARTER CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended December 31, 2014			Three months ended December 31, 2013		
(millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	16,073	26,745	42,818	16,703	21,028	37,731
Natural gas liquids (bbls/day)	2,315	1,172	3,487	2,858	955	3,813
Natural gas (Mcf/day)	140,910	214,799	355,709	165,114	150,625	315,739
Total average daily production (BOE/day)	41,873	63,718	105,591	47,080	47,087	94,167
Pricing(2)						
Crude oil (per bbl)	$ 67.15	$ 67.12	$ 67.13	$ 70.05	$ 83.89	$ 77.77
Natural gas liquids (per bbl)	48.67	23.94	40.36	52.39	59.87	54.26
Natural gas (per Mcf)	3.54	2.84	3.12	3.12	3.41	3.26
Capital Expenditures						
Capital spending	$ 65.1	$ 115.9	$ 181.0	$ 102.1	$ 120.9	$ 223.0
Acquisitions	–	1.3	1.3	0.4	173.0	173.4
Dispositions	(17.9)	–	(17.9)	(168.7)	0.7	(168.0)
Netback Before Hedging						
Oil and natural gas sales	$ 162.6	$ 230.9	$ 393.5	$ 175.5	$ 221.5	$ 397.0
Royalties	(22.5)	(45.8)	(68.3)	(23.7)	(40.9)	(64.6)
Cash operating expense	(63.8)	(40.6)	(104.4)	(66.2)	(24.4)	(90.6)
Production taxes	(2.8)	(17.6)	(20.4)	(2.3)	(15.6)	(17.9)
Transportation expense	(6.7)	(9.6)	(16.3)	(6.8)	(10.9)	(17.7)
Netback before hedging	$ 66.8	$ 117.3	$ 184.1	$ 76.5	$ 129.7	$ 206.2
Other Expenses						
Commodity derivative instruments gain	$ (219.8)	$ –	$ (219.8)	$ (10.2)	$ –	$ (10.2)
G&A expense(3)	17.2	7.6	24.8	23.0	6.3	29.3
Current income tax expense/(recovery)	–	(6.4)	(6.4)	(0.4)	0.3	(0.1)

(1) Company interest volumes.

(2) Net of transportation costs, but before royalties and the effects of commodity derivative instruments.

(3) G&A expense above includes share based compensation.

2015 OUTLOOK

In response to the decline in commodity prices we have reduced our capital spending and dividend to protect our balance sheet. We plan to defer capital spending across all of our core areas in 2015, preserving our opportunities until we see meaningful cost reductions or an improvement in commodity prices. We are now forecasting capital spending of $480 million, a decrease of approximately 40% from our spending levels in 2014. We have also announced a 44% reduction in our monthly dividend to $0.05 per share, effective for our April 2015 dividend payment. We believe the reductions in capital spending and dividends are prudent in the current commodity price environment, and will help to preserve our financial flexibility in both the near and long-term.

Subsequent to year end, we entered into two agreements to sell non-core assets with production of approximately 1,900 BOE/day for proceeds of $182.0 million, consisting primarily of our Pembina waterflood properties. Despite the low decline nature of these properties, high operating costs and limited future upside potential impacted our ability to direct capital given better opportunities within our portfolio. We expect to use the divestment proceeds to pay down our bank debt, which will further improve our liquidity in 2015.

Our commodity hedging program will also help to protect our funds flow and balance sheet in 2015. We have approximately 52% of our forecasted net crude oil production after royalties hedged at just under US$92/bbl for the first half of the year, and approximately 26% hedged for the second half of the year at just under US$94/bbl. In relation to these crude oil swaps, we have sold puts that effectively convert a portion of these swaps (approximately 13% of our forecasted net crude oil production) to WTI monthly index plus US$30.30/bbl if actual WTI monthly average prices settle below US$62.23/bbl. We also have approximately 40% of forecasted natural gas production after royalties protected at an average floor price of US$4.14/Mcf in 2015.

We expect production curtailments at our Marcellus properties will persist into 2015, averaging approximately 6,000 – 7,000 BOE/day for the year, as we look to preserve natural gas volumes in the low commodity price environment. As a result of these curtailments and non-core asset dispositions we are expecting average production for 2015 of 93,000 – 100,000 BOE/day, a decrease of approximately 6% from 2014, using the mid-point of guidance. Without the impact of curtailments and divestments, we would expect 2015 production levels to be consistent with 2014.

We expect operating expenses to increase slightly to $11.10/BOE in 2015 as a result of the forecasted production curtailments on our lower operating cost Marcellus properties, along with the impact of the weakening Canadian dollar on our U.S. operating costs. Our cash G&A expenses on a per BOE basis are also expected to increase slightly to $2.40/BOE due to the impact of lower production volumes.

Our balance sheet remained stable at December 31, 2014, with a debt to funds flow ratio of 1.3x and less than 10% drawn on our $1 billion credit facility. At December 31, 2014 our Senior Debt to Earnings before Interest, Taxes, Depreciation, Amortization and other non-cash charges ("EBITDA") was 1.3x, significantly lower than our most restrictive debt covenant which limits this ratio to 3.5x for a period of up to six months, reverting to 3.0x thereafter.

2014 OVERVIEW

Summary of Guidance and Results	Original 2014 Guidance	Revised 2014 Guidance	2014 Results	2015 Guidance
Average annual production (BOE/day)	96,000 – 100,000	102,000 – 104,000	103,130	93,000 – 100,000
Production mix (% crude oil and liquids)	48%	43%(1)	42%	42% – 44%
Capital spending (CDN$ millions)	$ 760	$ 830	$ 811	$ 480
Royalties, including state fees (% of gross sale, net of transportation)	23.5%	23%	23%	21%
Operating costs (per/BOE)	$ 10.25	$ 10.25	$ 10.43	$ 11.10
G&A Expenses – cash (per/BOE)	$ 2.45	$ 2.30	$ 2.22	$ 2.40
U.S. cash taxes (% of U.S. funds flow)	3 – 5%	2%	1%	< 1%

(1) Crude oil and liquids guidance revised to 44,000 BOE/day. Percentage above has been calculated using 103,000 BOE/day, the midpoint of the revised average annual production guidance.

We delivered annual production growth of 15% in 2014 with annual average production of 103,130 BOE/day, meeting our annual average guidance of 102,000 – 104,000 BOE/day despite Marcellus production curtailments and the sale of 3,500 BOE/day of non-core assets. Our crude oil and liquids production averaged approximately 43,800 BOE/day, in line with our target of 44,000 BOE/day. The continued growth in the Marcellus resulted in natural gas production increasing 23% over last year.

Capital spending totaled $811.0 million, lower than our target of $830.0 million, as we slowed spending in the fourth quarter in response to the rapid decrease in commodity prices. G&A expenses were $2.22/BOE, beating our guidance of $2.30/BOE, and cash share based compensation expenses came in significantly under guidance due to a decline in our share price during the fourth quarter. Operating costs of $10.43/BOE were slightly higher than our guidance of $10.25/BOE due to higher than expected production curtailments on our Marcellus properties that averaged 5,000 BOE/day in the second half of 2014.

Net income increased to $299.1 million from $48.0 million in 2013 as a result of an increase in oil and natural gas sales and commodity hedging gains. Funds flow increased by 14% year over year to $859.0 million, mainly due to higher production levels and improved average prices during the year.

RESULTS OF OPERATIONS

Production

Average Daily Production Volumes	2014	2013	2012
Crude oil (bbls/day)	40,208	38,250	36,509
Natural gas liquids (bbls/day)	3,565	3,472	3,627
Natural gas (Mcf/day)	356,142	288,423	251,773
Total daily sales (BOE/day)	103,130	89,793	82,098

2014 versus 2013

Production for 2014 increased 15% over 2013 and met our guidance range of 102,000 – 104,000 BOE/day, averaging 103,130 BOE/day. This was achieved despite curtailments in the Marcellus during the second half of 2014 and the sale of 3,500 BOE/d of non-core assets.

Our 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. Our production volumes in the Marcellus nearly doubled in 2014, averaging approximately 188,000 Mcf/day from 95,000 Mcf/day in 2013. This increase was despite the impact of production curtailments due to low realized prices in Northeast Pennsylvania that averaged 30,000 Mcf/day or 5,000 BOE/day during the second half of 2014. We expect these curtailments to continue in 2015 as long as realized prices remain low.

Our production mix for 2014 was 42% crude oil and natural gas liquids and 58% natural gas, compared to 46% and 54%, respectively, in 2013.

2013 versus 2012

Production for 2013 averaged 89,793 BOE/day, representing an increase of over 9% from 2012. Our crude oil production increased 5% with production from our Fort Berthold properties growing by approximately 4,700 BOE/day during the year. Our natural gas production increased 15% primarily due to growth in the Marcellus where we more than doubled our production volumes from the prior year. Somewhat offsetting the production growth were 2,700 BOE/day of non-core asset divestments throughout 2013 as well as production declines in our Canadian conventional natural gas properties due to limited capital investment.

2015 Guidance

We expect annual average production for 2015 of 93,000 – 100,000 BOE/day. This guidance includes the impact of our early 2015 asset dispositions with production of approximately 1,900 BOE/day and assumes curtailments of approximately 6,000 – 7,000 BOE/day of our Marcellus natural gas production for the full year, consistent with curtailment levels in the fourth quarter of 2014. Without the impact of curtailments and divestments, 2015 production would have been essentially flat despite a reduction in capital spending of approximately 40% and a full year impact of 2014 divestments.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, funds flow and financial condition. The following tables summarize our average selling prices, benchmark prices and differentials.

Pricing (average for the period)	2014	2013	2012
Benchmarks			
WTI crude oil (US$/bbl)	$ 93.00	$ 97.97	$ 94.21
AECO natural gas – monthly index (CDN$/Mcf)	4.42	3.16	2.40
AECO natural gas – daily index (CDN$/Mcf)	4.51	3.17	2.39
NYMEX natural gas – last day (US$/Mcf)	4.41	3.65	2.79
USD/CDN exchange rate	1.10	1.03	1.00
Enerplus selling price(1)			
Crude oil (CDN$/ bbl)	$ 84.53	$ 83.99	$ 78.19
Natural gas liquids (CDN$/ bbl)	49.89	52.25	53.01
Natural gas (CDN$/ Mcf)	3.81	3.26	2.39
Average differentials			
MSW Edmonton – WTI (US$/bbl)	$ (7.17)	$ (7.57)	$ (7.79)
WCS Hardisty – WTI (US$/bbl)	(19.40)	(25.20)	(21.03)
Brent Futures (ICE) – WTI (US$/bbl)	6.51	10.77	17.45
AECO monthly – NYMEX (US$/Mcf)	(0.41)	(0.58)	(0.39)
Enerplus realized differentials(1)			
Canada crude oil – WTI (US$/bbl)	$ (18.56)	$ (22.57)	$ (18.96)
Canada natural gas – NYMEX (US$/Mcf)	(0.60)	(0.73)	(0.62)
Bakken crude oil – WTI (US$/bbl)	(14.79)	(11.09)	(11.99)
Marcellus natural gas – NYMEX (US$/Mcf)	(1.45)	(0.33)	0.04

(1) Net of oil and gas transportation costs, but before the effects of royalties and commodity derivative instruments.

CRUDE OIL AND NATURAL GAS LIQUIDS

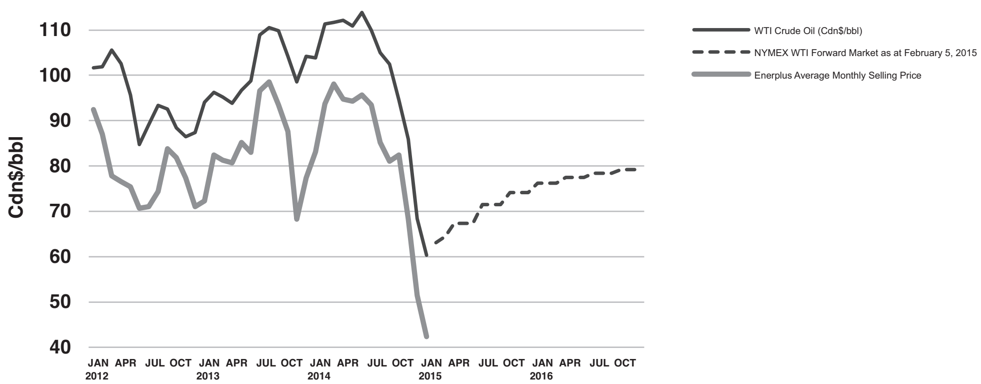
WTI prices averaged US$93.00/bbl for 2014. Daily WTI prices peaked at US$107.26/bbl in June as regional conflict in Iraq increased concern over supply disruptions. Over the second half of the year, we saw continued growth in non-OPEC crude production and weaker crude oil demand from deteriorating economic conditions in Europe and China, which created significant inventory builds and an imbalance between supply and demand worldwide. The market looked to OPEC to reduce its production quota in November to help restore this balance, however, OPEC decided to maintain its production levels to defend market share. Without OPEC production cuts, WTI prices reached a daily low of US$53.27/bbl as we exited the year and continued to fall to a daily low of US$44.45/bbl in late January 2015 as U.S. crude oil storage levels increased to approximately 85% of capacity.

Heavy crude differentials in Canada improved significantly in 2014, averaging US$19.40/bbl below WTI, US$5.80/bbl narrower than in 2013. This improvement was due to increased pipeline and rail capacity made available to transport heavy crude oil out of Canada into the U.S. Midwest and Gulf Coast. Light oil differentials in Canada were largely unchanged in 2014, averaging US$7.17/bbl below WTI for the year. Our realized crude oil differential in the Bakken was US$14.79/bbl below WTI, wider than 2013 due to increasing supplies of light sweet crude oil in the U.S. and wider differentials for crude oil delivered by rail in the U.S.

The average price received for our crude oil (net of transportation costs) was $84.53/bbl for 2014, a 1% increase over 2013. In comparison, the WTI benchmark fell by 5% over the same period. The difference between our realized price and changes in WTI prices was primarily due to the impact of a weaker Canadian dollar throughout 2014.

In 2015 we expect our U.S. Bakken production will receive an average discount of US$12.50/bbl to WTI including field transportation costs. In Canada, we expect the Mixed Sweet Blend ("MSW") will trade at US$5.00/bbl discount and Western Canadian Select ("WCS") will trade at a US$16.00/bbl discount to WTI during 2015.

MONTHLY CRUDE OIL PRICES



NATURAL GAS

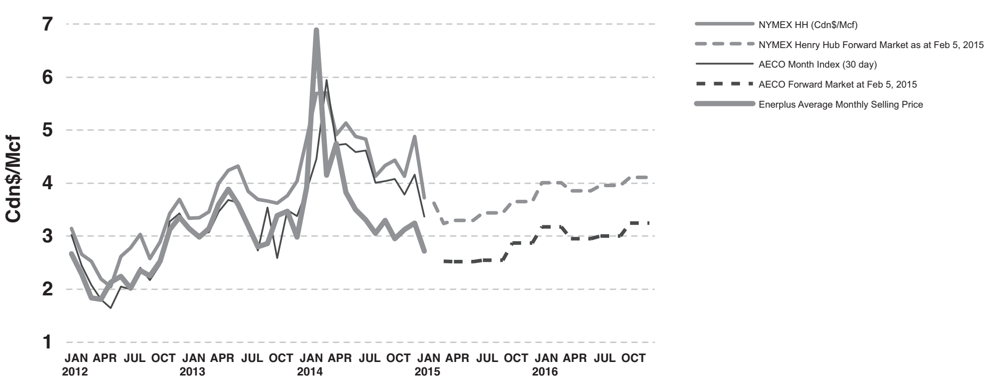
Both AECO and NYMEX natural gas prices strengthened significantly during 2014. AECO monthly index prices increased by 40% over 2013 to average $4.42/Mcf and NYMEX last day prices increased by 21% to average US$4.41/Mcf during the year. A very cold winter depleted natural gas storage levels to record lows in key demand centres in the U.S., driving gas prices higher with monthly NYMEX prices reaching a peak of US$5.56/Mcf in February. However, record dry gas production in the U.S. and cooler than normal summer weather that reduced natural gas power generation demand caused NYMEX natural gas prices to weaken over the remainder of the year. Continued production growth and a warmer than average winter resulted in weakness in NYMEX natural gas prices, which reached a low daily settlement of US$2.69/Mcf at the end of January 2015.

The basis differential between AECO monthly index and NYMEX gas averaged US$0.41/Mcf below NYMEX, compared to US$0.58/Mcf below NYMEX in 2013. This improvement was due to the severe depletion of natural gas storage levels in Western Canada through the winter followed by slower than expected injections of gas back into storage that were needed to sufficiently replenish inventories by the end of October.

Realized natural gas prices in the Marcellus continued to weaken throughout the year as production growth outpaced the increase in pipeline capacity. Monthly prices on both the Transco Leidy and Tennessee Gas Pipeline 300 Leg averaged US$1.80/Mcf and $2.05/Mcf below NYMEX in 2014 and prices at Dominion South Point averaged $1.14/Mcf below NYMEX. Our realized price differential in the Marcellus averaged US$1.45/Mcf below NYMEX versus a discount of US$0.33/Mcf in 2013. We expect our realized Marcellus differential will average approximately US$1.25/Mcf below NYMEX in 2015. We expect this differential will narrow as infrastructure gets built in key producing regions.

Overall, we sold our natural gas for an average price of $3.81/Mcf (net of transportation costs) in 2014 which represented a 17% increase from 2013. The increase in our realized price was in line with the year-over-year increases in both AECO and NYMEX prices, but was offset by significantly wider discounts in the Marcellus.

MONTHLY NATURAL GAS PRICES



FOREIGN EXCHANGE

The Canadian dollar weakened by approximately 9% against the U.S. dollar during 2014, with the USD/CDN exchange rate opening the year at 1.06 and closing the year at 1.16. The drop in the Canadian dollar was due to weakening economic conditions in Canada versus a strengthening economy in the U.S. The precipitous decline in crude oil prices accelerated the decline in the Canadian dollar in the fourth quarter. Downward pressure continued in 2015 with the USD/CDN exchange rate increasing to highs of 1.28 in January. 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 operating 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 2014 third quarter report we added additional floor protection on our natural gas production primarily in the second half of 2015, as we could see gas prices decline further if there is a risk of storage becoming full prior to the winter withdrawal season in October 2015. We added floor protection on an average of 10,000 Mcf/day for April to June 2015 and 45,000 Mcf/day for July to December 2015 at an average NYMEX price of $3.81/Mcf. Although we have significant crude oil hedges in place, we recently swapped an additional 2,000 bbls/day of crude oil for the months of March and April 2015 at a WTI price of US$52.17/bbl to protect against continued rising crude oil inventories in the short term which may drive WTI prices lower.

As of February 5, 2015 we have swapped 16,174 bbls/day of our crude oil production for the first half of 2015 at an average WTI price of US$91.86/bbl, which represents approximately 52% of our 2015 forecasted net oil production after royalties. For the second half of 2015 we have swapped 8,000 bbls/d at an average WTI price of US$93.86/bbl, which represents 26% of our 2015 forecasted net oil production after royalties. In relation to these swaps, we have purchased call options to participate in price upside above US$93.00/bbl on 4,000 bbls/day, and sold put options at an average strike price of US$62.23/bbl, offsetting the call premium. If actual monthly WTI prices fall below US$62.23/bbl for individual months during 2015, our swaps on approximately 13% of our forecasted net crude oil production are effectively converted to WTI monthly index plus US$30.30/bbl, using a weighted average swap price for the year of $92.53/bbl. Additionally, we have entered into WCS differential swap positions to manage some of our exposure to Canadian crude oil differentials. Overall, we expect our crude related hedge contracts to protect a significant portion of our funds flow during 2015.

As of February 5, 2015 we have downside protection on approximately 102,500 Mcf/day of our natural gas production for 2015 consisting of a combination of NYMEX swaps and collars with an average overall floor price of US$4.14/Mcf. This represents approximately 40% of our forecasted natural gas production after royalties. In relation to the swaps we have purchased a call spread on 5,000 Mcf/d to participate in NYMEX price upside and sold NYMEX put options on 5,000 Mcf/day at an average strike price of US$3.25/Mcf to offset the net cost of the call spread. For 2016, we have swapped 10,000 Mcf/day at a NYMEX price of US$4.03/Mcf, which represents 4% of our forecasted net gas production after royalties.

The following is a summary of our financial contracts in place at February 5, 2015, expressed as a percentage of our anticipated net production volumes:

	WTI Crude Oil (US$/bbl)[1]		NYMEX Natural Gas (US$/Mcf)				
	Jan 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Dec 31, 2015	Jan 1, 2015 – Mar 31, 2015	Apr 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Sep 30, 2015	Oct 1, 2015 – Dec 31, 2015	Jan 1, 2016 – Dec 31, 2016
Downside Protection Swaps							
Sold Swaps	$ 91.86	$ 93.86	$ 4.25	$ 4.21	$ 3.98	$ 4.04	$ 4.03
%	52%	26%	31%	35%	45%	37%	4%
Downside Protection Collars							
Purchased Puts	–	–	$ 4.53	–	–	–	–
%	–	–	12%	–	–	–	–
Sold Calls	–	–	$ 5.53	–	–	–	–
%	–	–	12%	–	–	–	–
Upside Participation Collars							
Sold Puts	$ 62.23	$ 62.23	$ 3.25	$ 3.25	$ 3.25	$ 3.25	–
%	12%	12%	2%	2%	2%	2%	–
Sold Calls	–	–	$ 5.00	$ 5.00	$ 5.00	$ 5.00	–
%	–	–	2%	2%	2%	2%	–
Purchased Calls	$ 93.00	$ 93.00	$ 4.29	$ 4.29	$ 4.29	$ 4.29	–
%	12%	12%	2%	2%	2%	2%	–

(1) Based on weighted average price (before premiums), assumed average annual production of 96,500 BOE/day for 2015 and 2016, less royalties and production taxes of 21% in aggregate.

During 2014, we entered into foreign exchange costless collars 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. As of February 5, 2015 we have US$24 million per month hedged for 2015 at an average USD/CDN floor of 1.1088, a ceiling of 1.1845 and a conditional ceiling of 1.1263. Under these contracts, if the monthly foreign exchange rate settles above the ceiling rate the conditional ceiling is used to determine the settlement amount.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Risk Management Gains/(Losses) ($ millions)	2014	2013	2012
Cash gains/(losses):			
Crude oil	$ 7.0	$ 24.4	$ 18.4
Natural gas	(3.5)	2.2	–
Total cash gains	$ 3.5	$ 26.6	$ 18.4
Non-cash gains/(losses):			
Change in fair value – crude oil	$ 182.0	$ (65.5)	$ 70.3
Change in fair value – natural gas	48.9	(3.0)	3.3
Total non-cash gains/(losses)	$ 230.9	$ (68.5)	$ 73.6
Total gains/(losses)	$ 234.4	$ (41.9)	$ 92.0

(Per BOE)	2014	2013	2012
Total cash gains	$ 0.09	$ 0.81	$ 0.61
Total non-cash gains/(losses)	6.14	(2.09)	2.45
Total gains/(losses)	$ 6.23	$ (1.28)	$ 3.06

During 2014 we realized cash gains of $7.0 million on our crude oil contracts and cash losses of $3.5 million on our natural gas contracts. In comparison, during 2013 and 2012 we realized cash gains of $24.4 million and $18.4 million, respectively, on our crude oil contracts and $2.2 million and nil, 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 $167.2 million and $49.2 million, respectively, at December 31, 2014, and a net loss position of $14.8 million and net gain position of $0.3 million, respectively, at December 31, 2013. The change in fair value of our crude oil and natural gas contracts represented gains of $182.0 million and $48.9 million, respectively, during 2014 and losses of $65.5 million and $3.0 million, respectively, during 2013.

During 2014, we entered into foreign exchange costless collars on our oil and natural gas sales. We recorded total cash gains of $0.7 million and non-cash mark-to-market losses of $8.4 million on these contracts. At December 31, 2014 the fair value of the costless collars was a net loss position of $8.4 million. See Note 16 for details.

Revenues

($ millions)	2014	2013	2012
Oil and natural gas sales	$ 1,849.3	$ 1,616.8	$ 1,365.5
Royalties	(323.1)	(264.3)	(212.2)
Oil and natural gas sales, net of royalties	$ 1,526.2	$ 1,352.5	$ 1,153.3

2014 versus 2013

Oil and natural gas sales revenue increased to $1,849.3 million in 2014 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 a significant increase in production.

2013 versus 2012

Oil and natural gas sales revenue increased to $1,616.8 million in 2013 compared to $1,365.5 million in 2012 due to higher realized prices and increased production for both crude oil and natural gas.

Royalties and Production Taxes

($ millions, except per BOE amounts)	2014	2013	2012
Royalties	$ 323.1	$ 264.3	$ 212.2
Per BOE	$ 8.58	$ 8.06	$ 7.06
Production taxes	$ 81.5	$ 70.4	$ 56.6
Per BOE	$ 2.17	$ 2.15	$ 1.89
Royalties and production taxes	$ 404.6	$ 334.7	$ 268.8
Per BOE	$ 10.75	$ 10.21	$ 8.95
Royalties and production taxes (% of oil and natural gas sales, net of transportation)	23%	21%	20%

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.

2014 versus 2013

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 were in line with our guidance for 2014, averaging 23% of oil and natural gas sales (net of transportation).

2013 versus 2012

Royalties and production taxes increased to $334.7 million in 2013 from $268.8 million in 2012 due to increased production from our higher royalty rate U.S. properties. Royalties and production taxes averaged 21% of oil and natural gas sales (net of transportation) in 2013 compared to 20% in 2012.

2015 Guidance

We expect royalty and production taxes in 2015 to average 21% of our oil and gas sales (net of transportation). A significant percentage of our production is from U.S. properties where royalty rates are generally not sensitive to commodity price levels.

Operating Expenses

($ millions, except per BOE amounts)	2014	2013	2012
Operating Expenses	$ 392.6	$ 343.4	$ 319.0
Per BOE	$ 10.43	$ 10.48	$ 10.62

2014 versus 2013

Our 2014 operating expenses totaled $392.6 million ($10.43/BOE) compared to $343.4 million ($10.48/BOE) in 2013. Our 2014 operating costs were slightly above our guidance of $10.25/BOE primarily due to production curtailments of approximately 5,000 BOE/day at our lower operating cost Marcellus properties in the second half of 2014. The impact of these curtailments increased our operating costs on a BOE basis by approximately $0.15/BOE. Non-cash hedging losses on our fixed price electricity swaps also increased our operating expenses for the year.

2013 versus 2012

Our 2013 operating expenses were in line with expectations at $343.4 million ($10.48/BOE) compared to $319.0 million ($10.62/BOE) in 2012. Operating costs improved on a per BOE basis due to increased production from our lower cost properties along with the divestment of non-core properties that had higher operating costs.

2015 Guidance

We are expecting operating expenses of $11.10/BOE in 2015. The increase on a BOE basis is due to estimated production curtailments of 6,000 – 7,000 BOE/day on our Marcellus properties along with the impact of a weaker Canadian dollar on operating costs incurred on our U.S. properties.

Transportation Costs

($ millions, except per BOE amounts)	2014	2013	2012
Transportation costs	$ 57.2	$ 39.9	$ 26.6
Per BOE	$ 1.52	$ 1.22	$ 0.88

Transportation costs for 2014 were $57.2 million ($1.52/BOE) compared to $39.9 million ($1.22/BOE) in 2013 and $26.6 million ($0.88/BOE) in 2012. The increase in transportation costs for 2014 and 2013 relate to our increasing U.S. production and costs associated with securing U.S. pipeline capacity.

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, 2014		
Netbacks by Property Type	**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[2]	$ 78.26	$ 3.94	$ 47.61
Royalties and production taxes	(19.78)	(0.61)	(10.75)
Cash operating costs	(12.79)	(1.42)	(10.40)
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

	Year ended December 31, 2013		
Netbacks by Property Type	**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[2]	$ 76.64	$ 3.57	$ 48.11
Royalties and production taxes	(18.22)	(0.45)	(10.21)
Cash operating costs	(12.38)	(1.46)	(10.50)
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

Netbacks by Property Type	Year ended December 31, 2012 Crude Oil	Natural Gas	Total
Average Daily Production	40,136 BOE/day	251,773 Mcfe/day	82,098 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 72.05	$ 3.04	$ 44.56
Royalties and production taxes	(16.06)	(0.36)	(8.95)
Cash operating costs	(11.94)	(1.52)	(10.51)
Netback before hedging	$ 44.05	$ 1.16	$ 25.10
Cash gains/(losses)	1.25	–	0.61
Netback after hedging	$ 45.30	$ 1.16	$ 25.71
Netback before hedging ($ millions)	$ 647.2	$ 107.1	$ 754.3
Netback after hedging ($ millions)	$ 665.6	$ 107.1	$ 772.7

(1) See "Non-GAAP Measures" in this MD&A.
(2) Net of transportation costs.

Our crude oil properties accounted for 76% of our corporate netback before hedging in 2014 compared to 81% and 86% in 2013 and 2012, respectively.

During 2014 crude oil netbacks per BOE decreased marginally while natural gas netbacks per Mcfe increased primarily due to improved realized prices compared to 2013. Our 2013 crude oil netbacks per BOE and natural gas netbacks per Mcfe increased compared to 2012 primarily due to improved realized prices.

General and Administrative ("G&A") Expenses

Total G&A expenses include cash G&A expenses as well as share based compensation charges related to our long-term incentive plans ("LTI plans") and our stock option plan (see Note 15 for further details). Share based compensation charges are dependent on our share price and can fluctuate from period to period.

($ millions)	2014	2013	2012
Cash:			
G&A expense	$ 83.5	$ 83.2	$ 78.3
Share based compensation expense/(recovery)	(1.2)	23.3	5.6
Non-Cash:			
Share based compensation expense	13.4	9.2	10.3
Equity swap loss/(gain)	9.3	(5.4)	(0.4)
Total G&A expenses	$ 105.0	$ 110.3	$ 93.8

(Per BOE)	2014	2013	2012
Cash:			
G&A expense	$ 2.22	$ 2.54	$ 2.61
Share based compensation expense/(recovery)	(0.03)	0.71	0.18
Non-Cash:			
Share based compensation expense	0.36	0.28	0.34
Equity swap loss/(gain)	0.24	(0.17)	(0.01)
Total G&A expenses	$ 2.79	$ 3.36	$ 3.12

2014 versus 2013

Our 2014 cash G&A expenses totaled $83.5 million ($2.22/BOE), beating our guidance of $2.30/BOE and similar to $83.2 million ($2.54/BOE) in 2013. On a per BOE basis, costs decreased by 13% due to higher production volumes in 2014.

Cash share based compensation was a recovery of $1.2 million in 2014 compared to a charge of $23.3 million in 2013. During 2014, our share price decreased by 42% resulting in a recovery of costs previously expensed. A portion of our LTI plans have a performance based multiplier that also decreased due to our relative total return in the Toronto Stock Exchange Oil and Gas Producers Index.

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 $9.3 million on these hedges in 2014. As of December 31, 2014 we have 950,000 units hedged at a weighted average price of $14.92/share.

2013 versus 2012

Cash G&A expenses were $83.2 million in 2013 compared to $78.3 million in 2012. The increase in 2013 was primarily related to compensation costs and one-time charges recorded in the first quarter. On a per BOE basis costs decreased 3%.

Cash share based compensation was $23.3 million in 2013 compared to $5.6 million in 2012. Higher cash share based compensation in 2013 was the result of our 58% total return in 2013 (share price increase plus dividends) which increased the value of our LTI plans. A portion of our LTI plans have a performance based multiplier that also increased this expense during 2013.

We recorded non-cash gains of $5.4 million in 2013 compared to gains of $0.4 million in 2012 on our equity swaps. At December 31, 2013 we had fixed the settlement cost on 1,130,000 units at a weighted average price of $13.86 per share.

2015 Guidance

For 2015, we expect cash G&A expenses of approximately $2.40/BOE, slightly higher than 2014 on a per BOE basis due to lower production volumes.

Interest Expense

($ millions)		2014		2013		2012
Interest on senior notes and bank facility	$	62.2	$	56.7	$	53.1
Non-cash interest expense		1.6		1.6		1.8
Total interest expense	$	63.8	$	58.3	$	54.9

Interest on our senior notes and bank credit facility in 2014 totaled $63.8 million compared to $58.3 million in 2013 and $54.9 million in 2012. Interest expense increased in 2014 due to the impact of a weaker Canadian dollar on our U.S. dollar denominated interest payments. We also had an increased weighting of senior notes with higher interest rates following our US$200.0 million private placement of senior notes in September 2014 and our $405.0 million private placement of senior notes in May 2012. The proceeds of these note issuances were used to repay lower floating rate bank debt.

Non-cash amounts recorded in interest expense include unrealized gains and losses resulting from the change in fair value of our interest rate swaps and the interest component on our cross currency interest rate swap ("CCIRS"). We have no further interest rate derivatives outstanding at December 31, 2014. See Note 12 for further details.

At December 31, 2014 approximately 93% of our debt was based on fixed interest rates and 7% on floating interest rates, with weighted average interest rates of 5.3% and 2.9%, respectively.

Foreign Exchange

($ millions)	2014	2013	2012
Realized loss	$ 11.2	$ 17.6	$ 6.5
Unrealized loss/(gain)	45.9	(8.3)	(23.7)
Total foreign exchange loss/(gain)	$ 57.1	$ 9.3	$ (17.2)

We recorded a net foreign exchange loss of $57.1 million in 2014 compared to a loss of $9.3 million in 2013 and gain of $17.2 million in 2012. Our foreign exchange exposure relates to fluctuations in the Canadian to U.S. dollar exchange rate and during 2014 the Canadian dollar weakened approximately 9% against the U.S. dollar.

Realized gains or losses can result from day-to-day transactions denominated in foreign currencies. In addition, our realized foreign exchange loss includes the second quarter CCIRS settlement on our US$175 million senior notes. Each year, upon settlement of the swap, we realized a foreign exchange loss (2014 – $15.8 million, 2013 – $17.8 million, 2012 – $18.4 million) and recognized 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.

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

Capital Investment

($ millions)	2014	2013	2012
Capital spending	$ 811.0	$ 681.4	$ 853.4
Office capital	7.0	6.5	11.9
Sub-total	$ 818.0	$ 687.9	$ 865.3
Property and land acquisitions	$ 18.5	$ 244.8	$ 185.3
Property divestments	(203.6)	(365.1)	(275.8)
Sub-total	$ (185.1)	$ (120.3)	$ (90.5)
Total	$ 632.9	$ 567.6	$ 774.8

2014

Capital spending in 2014 totaled $811.0 million, slightly under our guidance of $830.0 million as spending slowed in the fourth quarter in response to the significant decline in crude oil prices. We continued to focus on our core development areas, spending $343.7 million on our Fort Berthold crude oil properties, $176.6 million on our Canadian crude oil properties, $124.5 million on our deep gas properties in Canada and $158.8 million on our Marcellus assets. 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 non-core 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.

On February 18, 2015 we entered into two agreements to sell additional non-core assets with production of approximately 1,900 BOE/day for proceeds of $182.0 million.

2013

Capital spending in 2013 totaled $681.4 million and was focused primarily on our core development areas with 66% targeting oil development. Throughout the year we spent $314.9 million on our Fort Berthold crude oil properties, $172.9 million on our Canadian crude oil properties,

$89.3 million on our deep gas properties in Canada and $78.7 million developing our Marcellus assets. 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 significant transactions included the additional working interests we acquired in our core 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 January 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.

2012

Capital spending in 2012 totaled $853.4 million with approximately 70% directed towards oil properties. We spent $441.6 million on our Fort Berthold crude oil property, $168.5 million on our Canadian crude oil properties and $69.5 million on our deep gas properties in Canada. We also spent $153.6 million on our Marcellus assets primarily focused on drilling for lease retention in core areas. Through our capital program in 2012 we added 58 MMBOE of gross proved plus probable reserves, replacing approximately 190% of our 2012 production.

Property and land acquisitions for 2012 totaled $185.3 million, the majority of which related to our December acquisition of additional working interests in our operated Sleeping Giant crude oil leases in Montana for $117.6 million. We also spent $37.0 million on our Marcellus carry obligation which fully satisfied our carry commitment.

Property divestments in 2012 included the sale of our Manitoba assets for proceeds of $218.1 million and non-core assets in the U.S. for proceeds of $21.9 million.

2015 Guidance

As a result of the continued weakness in commodity prices, we are reducing our capital spending to $480 million, approximately 40% below 2014 levels. We plan to defer capital spending across all of our core areas in 2015 to preserve opportunities until we see a significant reduction in costs or an improvement in realized prices.

Depletion, Depreciation, Amortization and Accretion ("DDA&A")

($ millions, except per BOE amounts)	2014	2013	2012
DDA&A expense	$ 566.7	$ 593.2	$ 560.3
Per BOE	$ 15.06	$ 18.10	$ 18.65

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. The decrease in DDA&A during 2014 was due to significant reserve additions at December 31, 2013 which lowered our depletion rate. The increase in 2013 was mainly due to higher production and capital costs with respect to our U.S. operations.

Impairments

($ millions, except per BOE amounts)	2014	2013	2012
Impairment expense	$ –	$ –	$ 781.1
Per BOE	$ –	$ –	$ 26.00

Under U.S. GAAP, the impairment test on our oil and natural gas properties is performed using estimated after-tax future net cash flows from proved reserves as calculated based on SEC constant prices using trailing 12-month average commodity prices and discounted at 10 percent ("Standardized Measure"). The Standardized Measure is not related to Enerplus' 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.

Enerplus did not record any ceiling test impairments on its oil and natural gas properties in 2014 or 2013. During 2012 non-cash impairments totaling $781.1 million were recorded in the United States cost centre. This impairment was due to capital spending not being fully offset by related increases in the Standardized Measure on our earlier stage U.S. growth assets, along with declines in the trailing 12-month average natural gas price during 2012.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' impairment test as at December 31, 2014, 2013 and 2012:

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
2014	$ 94.99	$ 1.09	$ 94.84	$ 4.30	$ 4.60
2013	96.94	1.03	93.19	3.67	3.16
2012	94.71	1.00	88.33	2.83	2.35

Based on the use of the 12-month average trailing benchmark prices, there is an increased risk of impairment on our oil and natural gas properties if commodity prices fail to recover during 2015.

Marketable Securities

During the first quarter of 2014 we sold the remainder of our publicly listed investments for proceeds of $13.3 million, recognizing a loss of $2.8 million. In 2013 and 2012, we sold the majority of our marketable securities portfolio for proceeds of $2.5 million and $146.9 million, respectively, realizing gains of $0.4 million and $86.5 million, respectively.

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 $288.7 million at December 31, 2014 compared to $291.8 million at December 31, 2013. See Note 9 for further information.

We take an active approach to managing our abandonment, reclamation and remediation obligations. During 2014 we spent $19.4 million (2013 – $16.6 million; 2012 – $19.9 million) on our asset retirement obligations and we expect to spend approximately $17.0 million in 2015. Our abandonment and reclamation costs are expected to be incurred over the next 65 years with the majority between 2029 and 2054. We do not reserve cash or assets for the purpose of funding our future asset retirement obligations. Any reclamation or abandonment costs are anticipated to be funded out of cash flow.

Taxes

Income Tax ($ millions)	2014	2013	2012
Current tax expense	$ 5.0	$ 7.9	$ 1.6
Deferred tax expense/(recovery)	132.8	30.7	(274.6)
Total tax expense/(recovery)	$ 137.8	$ 38.6	$ (273.0)

Our current tax expense is comprised mainly of Alternative Minimum Tax ("AMT") payable with respect to our U.S. subsidiary. We expect to recover AMT in future years as an offset to regular U.S. income taxes otherwise payable.

2014 versus 2013

Our 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 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 increased our deferred tax expense in 2014.

2013 versus 2012

Total tax expense in 2013 was $38.6 million compared to a recovery of $273.0 million in 2012. The increase in tax is primarily related to higher net income in 2013 compared to 2012, which included $781.1 million in non-cash ceiling test impairments in our U.S. cost centre.

2015 Guidance

In 2015, we expect to pay cash taxes (AMT) of less than 1% of U.S. funds flow and do not expect to pay any cash taxes in Canada. These estimates may vary depending on numerous factors including commodity prices, capital spending, tax regulations and acquisition and divestment activity.

Tax Pools

Our estimated tax pools at December 31, 2014 are as follows:

Pool Type ($ millions)	**2014**
Canada	
Canadian oil and gas property expenditures ("COGPE")	$ –
Canadian development expenditures ("CDE")	383
Canadian exploration expenditures ("CEE")	235
Undepreciated capital costs ("UCC")	280
Non-capital losses and other credits	441
	$ 1,339
U.S.	
Alternative minimum tax credit ("AMT")	$ 113
Net operating losses	592
Depletable and depreciable assets	1,227
	$ 1,932
Total tax pools and credits	$ 3,271
Capital losses – Canada	$ 1,207

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.

SELECTED ANNUAL CANADIAN AND U.S. FINANCIAL RESULTS

	Year ended December 31, 2014			**Year ended December 31, 2013**		
(millions, except per unit amounts)	**Canada**	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	16,667	23,541	40,208	17,862	20,388	38,250
Natural gas liquids (bbls/day)	2,477	1,088	3,565	2,801	671	3,472
Natural gas (Mcf/day)	150,930	205,212	356,142	175,876	112,547	288,423
Total average daily production (BOE/day)	44,299	58,831	103,130	49,976	39,817	89,793
Pricing(2)						
Crude oil (per bbl)	$ 82.21	$ 86.17	$ 84.53	$ 77.67	$ 89.52	$ 83.99
Natural gas liquids (per bbl)	55.32	37.53	49.89	55.51	38.64	52.25
Natural gas (per Mcf)	4.20	3.52	3.81	3.01	3.66	3.26
Capital Expenditures						
Capital spending	$ 308.3	$ 502.7	$ 811.0	$ 286.5	$ 394.9	$ 681.4
Acquisitions	2.0	16.5	18.5	44.4	200.4	244.8
Dispositions	(154.6)	(49.0)	(203.6)	(323.2)	(41.9)	(365.1)
Netback Before Hedging						
Oil and natural gas sales	$ 807.9	$ 1,041.4	$ 1,849.3	$ 782.3	$ 834.5	$ 1,616.8
Royalties	(118.8)	(204.3)	(323.1)	(105.8)	(158.5)	(264.3)
Cash operating expense	(252.9)	(138.4)	(391.3)	(259.9)	(84.3)	(344.2)
Production taxes	(9.2)	(72.3)	(81.5)	(10.1)	(60.3)	(70.4)
Transportation expense	(24.6)	(32.6)	(57.2)	(24.1)	(15.8)	(39.9)
Netback before hedging	$ 402.4	$ 593.8	$ 996.2	$ 382.4	$ 515.6	$ 898.0
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (234.4)	$ –	$ (234.4)	$ 41.9	$ –	$ 41.9
General and administrative expense	79.1	25.9	105.0	92.4	17.9	110.3
Current income tax expense/(recovery)	(0.5)	5.5	5.0	(0.6)	8.5	7.9

(1) Company interest volumes.
(2) Net of transportation costs, but before royalties and the effects of commodity derivative instruments.
(3) General and administrative expense above includes share based compensation.

THREE YEAR SUMMARY OF KEY MEASURES

($ millions, except per share amounts)	2014	2013	2012
Oil and natural gas sales, net of royalties	$ 1,526.2	$ 1,352.5	$ 1,153.3
Net income/(loss)	299.1	48.0	(270.7)
Per share (Basic)	1.46	0.24	(1.38)
Per share (Diluted)	1.44	0.24	(1.38)
Funds flow	859.0	754.2	644.5
Cash and stock dividends(1)	221.1	216.9	301.6
Per share (Basic)(1)	1.08	1.08	1.54
Total assets	4,082.3	3,681.8	3,618.4
Long-term debt, net of cash(2)	1,134.9	1,022.3	1,064.4

(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.

2014 versus 2013

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

2013 versus 2012

Oil and gas sales, net income and funds flow improved in 2013 due to increased production volumes and higher realized prices. Net income in 2012 was also impacted by non-cash asset impairment charges.

Cash and stock dividends were lower in 2013 than 2012 due to the reduction in our monthly dividend from $0.18 per month to $0.09 per month, effective July 2012.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share	
			Basic	Diluted
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
2013				
Fourth Quarter	$ 332.4	$ 29.6	$ 0.15	$ 0.15
Third Quarter	365.4	(3.7)	(0.02)	(0.02)
Second Quarter	341.3	38.5	0.19	0.19
First Quarter	313.4	(16.4)	(0.08)	(0.08)
Total 2013	$ 1,352.5	$ 48.0	$ 0.24	$ 0.24

Oil and natural gas sales, net of royalties, generally increased throughout 2013 and the first half of 2014 due to production growth and increasing realized prices. As commodity prices steadily declined in the second half of 2014, oil and natural gas sales also decreased.

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. Net income in 2013 was impacted primarily by fluctuating risk management costs.

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 and dividend levels. We also assess our leverage relative to our most restrictive debt covenant, which is a Senior Debt to Earnings before Interest, Taxes, Depreciation, Amortization and other non-cash charges ("EBITDA") threshold of 3.5x for a period of up to six months, after which it drops to 3.0x. At December 31, 2014 our Senior Debt to EBITDA ratio was 1.3x and our debt to funds flow ratio was 1.3x. Subsequent to year end, we entered into agreements to sell additional non-core assets, including our Pembina waterflood properties, for proceeds of $182.0 million. We plan to use the proceeds in part to pay down our debt which will improve our liquidity and financial flexibility going into 2015.

Total debt net of cash at December 31, 2014 was $1,134.9 million compared to $1,022.3 million at December 31, 2013. Total debt is comprised of $79.9 million of bank indebtedness and $1,057.0 million of senior notes less $2.0 million in cash. On September 3, 2014 we closed a private placement of US$200.0 million senior unsecured notes with a twelve year amortizing term and a fixed interest rate of 3.79%, the proceeds of which were used to repay our short-term, floating rate bank debt. Consequently, at year end, less than 10% of our senior, unsecured bank credit facility was drawn. The maturities on our senior notes range between 2015 and 2026, with approximately $100 million of scheduled principal repayments during 2015 and none in 2016.

Our working capital deficiency, excluding cash and current deferred financial and tax balances, decreased to $260.5 million at December 31, 2014 from $271.4 million at December 31, 2013. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by funds flow, was 118% for 2014 compared to 114% in 2013. Despite the increase in our adjusted payout ratio, we have continued to maintain our financial flexibility through an ongoing focus on cost efficiencies and the success of our non-core asset divestment program. During 2014, we recorded net acquisition and divestment proceeds of $185.1 million and used the funds to finance a portion of our capital spending program. After adjusting for net acquisition and divestment proceeds, our adjusted payout ratios for 2014 and 2013 decrease to 97% and 98%, respectively.

We have a $1.0 billion senior, unsecured, covenant-based bank credit facility that matures on October 31, 2017. Drawn and undrawn fees range between 150 and 315 basis points over Bankers' Acceptance rates, with current drawn fees of 170 basis points. The bank credit facility ranks equally with our senior, unsecured, covenant-based notes. At December 31, 2014 we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at www.sedar.com. The following table lists our financial covenants as at December 31, 2014:

Covenant Description		December 31, 2014
Bank Credit Facility:	**Maximum Ratio**	
Senior Debt to EBITDA	3.5 x	1.3 x
Total Debt to EBITDA	4.0 x	1.3 x
Total Debt to Capitalization(1)	50%	26%
Senior Notes:	**Maximum Ratio**	
Senior Debt to EBITDA(2)	3.0x – 3.5 x	1.3x
Maximum debt to consolidated present value of total proved reserves	60%	37%
	Minimum Ratio	
EBITDA to Interest	4.0 x	14.4 x

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.

"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 Shareholders' Equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes
(1) Upon completion of a material acquisition, the Total Debt to Capitalization maximum ratio may increase to 55% for a period extending to and including the second full fiscal quarter after the completion of the acquisition
(2) 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

Counterparty Credit

OIL AND NATURAL GAS SALES COUNTERPARTIES

Our oil and natural gas receivables are with customers in the oil and gas business 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. 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 some 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, 2014 we had $246.7 million in mark-to-market assets offset by $13.2 million of mark-to-market liabilities resulting in a net asset position of $233.5 million. The majority of our outstanding derivative contracts are with 11 financial institutions, 7 of which are members of our bank syndicate. All of our derivative counterparties are considered investment grade.

Dividends

($ millions, except per share amounts)	2014	2013	2012
Cash dividends[1]	$ 199.3	$ 170.7	$ 278.0
Stock Dividend Plan	21.8	46.2	23.6
Total dividends to shareholders	$ 221.1	$ 216.9	$ 301.6
Per weighted average share (Basic)	$ 1.08	$ 1.08	$ 1.54

(1) Includes former Dividend Reinvestment Plan proceeds of $19.2 million in 2012

We reported a total of $221.1 million or $1.08 per share in dividends to our shareholders in 2014. Dividends during 2013 and 2012 were $216.9 million or $1.08 per share and $301.6 million or $1.54 per share, respectively.

Effective September 19, 2014 the Board of Directors elected to suspend the Stock Dividend Plan ("SDP") in an effort to eliminate the dilution associated with the issuance of shares through the plan.

Effective July 20, 2012 we reduced our monthly dividend from $0.18 per share to $0.09 per share.

2015 GUIDANCE

We are reducing the dividend from $0.09 per share to $0.05 per share effective with the April 2015 payment to help maintain our balance sheet strength in both the near and long term. The dividend is an important part of our strategy to create shareholder value and we will continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	2014	2013	2012
Share capital ($ millions)	$ 3,120.0	$ 3,061.8	$ 2,997.7
Common shares outstanding (thousands)	205,732	202,758	198,684
Weighted average shares outstanding – basic (thousands)	204,510	200,567	195,633
Weighted average shares outstanding – diluted (thousands)	207,424	201,404	195,633

During 2014 a total of 2,974,000 shares (2013 – 4,074,000; 2012 – 2,816,000) and $53.2 million of additional equity (2013 – $61.0 million; 2012 – $43.9 million) was issued pursuant to the SDP, our former Dividend Reinvestment Plan ("DRIP") and the stock option plan. For further details see Note 15.

At February 19, 2015 we had 205,920,733 shares outstanding.

On February 8, 2012 we completed a bought deal equity financing of 14,708,500 common shares at a price of $23.45 per share for gross proceeds of $344.9 million ($330.6 million net of issuance costs).

Commitments

As at December 31, 2014 we had the following minimum annual commitments:

		Minimum Annual Commitment Each Year					Total
($ millions)	Total	2015	2016	2017	2018	2019	Committed after 2019
Bank credit facility	$ 79.9	$ –	$ –	$ 79.9	$ –	$ –	$ –
Senior notes(3)	1,057.0	98.9	–	52.2	52.2	82.2	771.5
Transportation commitments	165.5	39.7	29.6	18.8	9.4	7.5	60.5
Processing commitments	58.8	11.4	11.3	10.8	9.3	5.7	10.3
Drilling and completions	19.3	19.3	–	–	–	–	–
Office leases	121.9	12.1	12.4	12.4	12.4	11.3	61.3
Total commitments(1)(2)	$ 1,502.4	$ 181.4	$ 53.3	$ 174.1	$ 83.3	$ 106.7	$ 903.6

(1) US$ commitments have been converted to CDN$ using the December 31, 2014 foreign exchange rate of 1.1601.

(2) 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.

(3) Interest payments have not been included.

We have various firm sales and transportation contracts in place for up to 16,000 bbls/day of our U.S. oil production through 2017.

We have contracted up to 182 MMcf/day of natural gas pipeline capacity with contract terms that range anywhere from one month to fifteen years.

During 2014, we extended our Canadian office lease by 5 years to 2024. 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 17.

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 Board of Directors' Safety and Social Responsibility ("S&SR") Committee is responsible for review of the policies, 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 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. 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 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.

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. Reserve estimates impact net income through depletion, the determination of decommissioning liabilities and the application of impairment tests. Revisions or changes in reserve estimates can have either a positive or a negative impact on net income.

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 amortized 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, reserve estimates, costs and technology.

Business Combinations

Management makes various assumptions in determining the fair values 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(m) in our Financial Statements for a detailed listing of Standards and Interpretations that were issued but not yet effective at December 31, 2014.

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 demand, weather conditions, the supply and 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 decline in crude oil or natural gas prices may have a material adverse effect on the Corporation's operations, financial condition, borrowing ability, levels of reserves and resources and the level of expenditures for the development of the Corporation's 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 the Corporation's production volumes, or its desire to market its production in unsatisfactory market conditions. Furthermore, the Corporation may be subject to the decisions of third party operators who, independently and using different economic parameters than the Corporation, 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 5, 2015, approximately 38% of our 2015 forecasted crude oil production is hedged at a price of US$92.53/bbl and approximately 40% of our forecasted natural gas production is hedged at a price of US$4.14/bbl. If actual monthly WTI prices fall below US$62.23/bbl in 2015, we are exposed to floating WTI prices below that level on 4,000 bbls/day and our downside protection is limited to US$30.30/bbl (assuming the WTI index falls to $0/bbl) on the volume of put options that were sold, using a weighted average swap price of $92.53/bbl. To date, we have no hedges on our forecasted crude oil production for 2016 and only 4% of our 2016 natural gas production is hedged, 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.

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 12-month average trailing benchmark prices, there is an increased risk of impairment on our oil and gas properties if commodity prices fail to recover during 2015.

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 most of 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 89% of the total proved plus probable value (discounted at 10%) of our reserves at December 31, 2014. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 71% 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. crude oil assets. Netherland, Sewell & Associates, Inc. (NSAI) evaluated 100% of our U.S. 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 resources 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 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.

We are listed on the Toronto and New York stock exchanges and maintain an active investor relations program. We provide continuous disclosure and maintain complete and timely public filings. Nonetheless, 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).

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. The assets of the Corporation 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 2015, 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 and. 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").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.

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.

Health, Safety and Environmental Risk ("HSE")

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 established an S&SR team that develops standards and systems to manage health, safety and environmental risks, regulatory compliance and stakeholder engagement for the organization. The actions of the S&SR team 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. The Corporation carries insurance to cover a portion of its property losses, liability and business interruption. At present, the Corporation believes that it is, and expects to continue to be, in compliance with all material applicable environmental laws and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet its ongoing environmental obligations.

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 and U.S. debt repayment is negatively impacted with a weak Canadian dollar.

We have hedged our foreign currency exposure on our US$54 million and a portion of our US$225 million senior notes using financial swaps that convert the U.S. denominated debt to Canadian dollar debt. We have also entered into foreign exchange costless collars on our oil and gas sales to hedge a floor exchange rate on a portion of our U.S. dollar denominated oil and natural gas sales. These collars have ceilings at an average USD/CDN rate of 1.1845, calculated monthly. If we exceed the ceiling foreign exchange rate during a given month, we are knocked back to an average conditional ceiling of 1.1263. Despite these foreign exchange instruments, much of our U.S. dollar exposure remains unhedged.

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 16 and are based on forward markets as at February 5, 2015. 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 2015 Funds Flow per Share[1]
Change of $0.50 per Mcf in the price of NYMEX natural gas	$ 0.18
Change of US$5.00 per barrel in the price of WTI crude oil	$ 0.27
Change of 1,000 BOE/day in production	$ 0.03
Change of $0.01 in the USD/CDN exchange rate	$ 0.02
Change of 1% in interest rate	$ 0.01

(1) Assumes 205.9 million weighted average shares outstanding.

2015 GUIDANCE

A summary of our 2015 guidance is below. This guidance includes the sale of non-core assets with production of approximately 1,900 BOE/day and is based on a WTI price of US$55/bbl, NYMEX of US$2.75/Mcf, AECO of $2.50/GJ and a USD/CDN exchange rate of 1.25. This guidance does not include any other potential acquisitions or divestments.

Summary of 2015 Expectations	Target
Average annual production	93,000 – 100,000 BOE/day
Marcellus annual average production curtailments	6,000 – 7,000 BOE/day
Crude oil and liquids (% of annual average production)	42% – 44%
Capital spending	$480 million
Royalties, including state fees (% of gross sales, net of transportation)	21%
Operating costs	$11.10/BOE
Cash G&A expenses	$2.40/BOE
U.S. Cash taxes (% of U.S. funds flow)	<1%

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a – 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109, Certification of Disclosure in 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, 2014, 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, 2014 and ended December 31, 2014 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 2015 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 proportion and average production volumes associated with operator-led curtailments in the Marcellus; 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 2015 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 costs; capital spending levels in 2015 and its impact on our production level and land holdings; our ability to reallocate funds within our 2015 capital program; potential future asset 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; 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 further curtailment of production and/or reduced realized prices; current commodity price and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and 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; the availability of third party services; and the extent of our liabilities. In addition, our 2015 guidance contained in this MD&A is based on the following: a WTI price of US$55/bbl, a NYMEX price of US$2.75/Mcf, an AECO price of $2.50/GJ and a CDN/USD exchange rate of 1.25. 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: changes in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inaccurate estimation of our oil and gas reserve and 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, 2014, 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, 2014, 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, 2014.

Ian C. Dundas
President and
Chief Executive Officer

Robert J. Waters
Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 19, 2015

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, 2014, 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 the management's report. 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 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 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 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, 2014, 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 at and for the year ended December 31, 2014 of the Company and our report dated February 19, 2015 expressed an unqualified opinion on those consolidated financial statements.

Deloitte LLP

Chartered Accountants

February 19, 2015
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 19, 2015. 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, Chartered 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 the 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

Robert J. Waters
Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 19, 2015

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, 2014 and December 31, 2013, 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, 2014, and 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, 2014 and December 31, 2013, and their financial performance and their cash flows for each of the years in the three-year period ended December 31, 2014 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, 2014, 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, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte LLP

Chartered Accountants

February 19, 2015
Calgary, Canada

Consolidated Balance Sheets

(CDN$ thousands)	Note	December 31, 2014	December 31, 2013
Assets			
Current assets			
Cash		$ 2,036	$ 2,990
Accounts receivable	3	199,745	165,091
Deferred income tax asset	14	–	48,476
Deferred financial assets	16	215,706	9,198
Other current assets		8,241	7,641
		425,728	233,396
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	4	2,632,474	2,420,144
Other capital assets, net	4	20,591	21,210
Property, plant and equipment		2,653,065	2,441,354
Goodwill		624,390	609,975
Deferred income tax asset	14	348,117	364,411
Deferred financial assets	16	30,997	19,274
Marketable securities	6	–	13,389
Total Assets		$ 4,082,297	$ 3,681,799
Liabilities			
Current liabilities			
Accounts payable	7	$ 351,006	$ 377,157
Dividends payable		18,516	18,250
Current portion of long-term debt	8	98,933	48,713
Deferred income tax liability	14	50,805	–
Deferred financial credits	16	10,826	37,031
		530,086	481,151
Deferred financial credits	16	2,396	–
Long-term debt	8	1,037,997	976,585
Asset retirement obligation	9	288,692	291,761
		1,329,085	1,268,346
Total Liabilities		1,859,171	1,749,497
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: December 31, 2014 – 206 million shares			
December 31, 2013 – 203 million shares	15	3,120,002	3,061,839
Paid-in capital	15	46,906	38,398
Accumulated deficit		(1,039,260)	(1,117,238)
Accumulated other comprehensive income/(loss)		95,478	(50,697)
		2,223,126	1,932,302
Total Liabilities & Equity		$ 4,082,297	$ 3,681,799
Commitments, Contingencies and Guarantees	17		

See accompanying notes to the Consolidated Financial 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**	**2014**	**2013**	**2012**
Revenues				
Oil and natural gas sales, net of royalties	10	$ 1,526,194	$ 1,352,472	$ 1,153,334
Commodity derivative instruments gain/(loss)	16	234,373	(41,870)	91,995
		1,760,567	1,310,602	1,245,329
Expenses				
Operating		392,564	343,433	319,031
Production taxes		81,522	70,388	56,624
Transportation		57,215	39,918	26,569
General and administrative	11	105,041	110,260	93,844
Depletion, depreciation, amortization and accretion		566,674	593,203	560,293
Asset impairment	5	–	–	781,099
Interest	12	63,788	58,337	54,907
Foreign exchange(gain)/loss	13	57,090	9,313	(17,204)
Other expense/(income)		(231)	(868)	(86,146)
		1,323,663	1,223,984	1,789,017
Income/(Loss) Before Taxes		436,904	86,618	(543,688)
Current income tax expense/(recovery)	14	4,998	7,889	1,648
Deferred income tax expense/(recovery)	14	132,830	30,753	(274,639)
Net Income/(Loss)		$ 299,076	$ 47,976	$ (270,697)
Other Comprehensive Income/(Loss)				
Changes due to marketable securities (net of tax)				
Unrealized gain/(loss)	6	(145)	7,136	(10,115)
Realized (gain)/loss reclassified to net income	6	2,503	(315)	–
Change in cumulative translation adjustment		143,817	72,867	(32,255)
Other Comprehensive Income/(Loss)		146,175	79,688	(42,370)
Total Comprehensive Income/(Loss)		$ 445,251	$ 127,664	$ (313,067)
Net Income/(Loss) per Share				
Basic	15	$ 1.46	$ 0.24	$ (1.38)
Diluted	15	$ 1.44	$ 0.24	$ (1.38)

See accompanying notes to the Consolidated Financial Statements

Consolidated Statements of Changes in Shareholders' Equity

For the year ended December 31 (CDN$ thousands)	2014	2013	2012
Share Capital			
Balance, beginning of year	$ 3,061,839	$ 2,997,682	$ 2,622,003
Public offering	–	–	330,618
Stock Option Plan – cash	31,350	14,838	1,180
Stock Option Plan – non cash	4,978	3,108	1,119
Dividend Reinvestment Plan	–	–	19,150
Stock Dividend Plan	21,835	46,211	23,612
Balance, end of year	$ 3,120,002	$ 3,061,839	$ 2,997,682
Paid-in Capital			
Balance, beginning of year	$ 38,398	$ 32,293	$ 23,115
Share-based compensation – exercised/settled	(4,978)	(3,108)	(1,119)
Share-based compensation – expensed	13,486	9,213	10,297
Balance, end of year	$ 46,906	$ 38,398	$ 32,293
Accumulated Deficit			
Balance, beginning of year	$ (1,117,238)	$ (948,350)	$ (376,093)
Net income/(loss)	299,076	47,976	(270,697)
Dividends	(221,098)	(216,864)	(301,560)
Balance, end of year	$ (1,039,260)	$ (1,117,238)	$ (948,350)
Accumulated Other Comprehensive Income/(Loss)			
Balance, beginning of year	$ (50,697)	$ (130,385)	$ (88,015)
Changes due to marketable securities (net of tax)			
Unrealized gain/(loss)	(145)	7,136	(10,115)
Realized (gain)/loss reclassified to net income	2,503	(315)	–
Change in cumulative translation adjustment	143,817	72,867	(32,255)
Balance, end of year	$ 95,478	$ (50,697)	$ (130,385)
Total Shareholders' Equity	$ 2,223,126	$ 1,932,302	$ 1,951,240

See accompanying notes to the Consolidated Financial Statements

Consolidated Statements of Cash Flows

For the year ended December 31 (CDN$ thousands)	Note	2014	2013	2012
Operating Activities				
Net income/(loss)		$ 299,076	$ 47,976	$ (270,697)
Non-cash items add/(deduct):				
Depletion, depreciation, amortization and accretion		566,674	593,203	560,293
Asset impairment	5	–	–	781,099
Changes in fair value of derivative instruments	16	(242,038)	35,088	(85,163)
Deferred income tax expense/(recovery)	14	132,830	30,753	(274,639)
Foreign exchange (gain)/loss on debt and working capital	13	68,202	19,747	(7,647)
Share-based compensation	15	13,486	9,213	10,297
Amortization of debt issue costs		968	793	(5)
Derivative settlement on senior notes		17,024	17,827	18,406
Asset disposition (gain)/loss		2,798	(367)	(87,421)
Asset retirement obligation expenditures	9	(19,409)	(16,606)	(19,905)
Changes in non-cash operating working capital	19	(52,414)	28,851	(88,929)
Cash flow from operating activities		787,197	766,478	535,689
Financing Activities				
Proceeds from the issuance of shares	15	31,350	14,838	350,948
Cash dividends	15	(199,263)	(170,653)	(277,948)
Change in bank credit facility		(136,918)	(45,556)	(189,251)
Proceeds/(repayment) of senior notes		167,497	(46,814)	359,852
Derivative settlement on senior notes		(17,024)	(17,827)	(18,406)
Changes in non-cash financing working capital		263	368	(14,727)
Cash flow from financing activities		(154,095)	(265,644)	210,468
Investing Activities				
Capital and office expenditures		(817,968)	(687,905)	(865,296)
Property and land acquisitions		(18,491)	(244,837)	(185,337)
Property dispositions		203,576	365,135	245,771
Sale of marketable securities	6	13,300	2,482	146,898
Changes in non-cash investing working capital		(17,449)	60,604	(90,252)
Cash flow from investing activities		(637,032)	(504,521)	(748,216)
Effect of exchange rate changes on cash		2,976	1,477	1,630
Change in cash		(954)	(2,210)	(429)
Cash, beginning of year		2,990	5,200	5,629
Cash, end of year		$ 2,036	$ 2,990	$ 5,200

See accompanying notes to the Consolidated Financial 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 19, 2015.

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, 2014 and 2013 and results of operations for the years ended December 31, 2014, and the 2013 and 2012 comparative years.

i. Functional and Reporting Currency

These Consolidated Financial Statements are presented in Canadian dollars, which is Enerplus' functional 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, amortization and accretion ("DDA&A"), impairment, asset retirement obligations, income taxes, contingent assets and liabilities, impairment assessments of goodwill, share-based compensation 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) 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, 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. 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.

Proceeds on property dispositions are accounted for as a reduction to the full cost pool without recognition of a gain or loss, unless the deduction significantly alters the relationship between capitalized costs and proved reserves in the cost centre.

d) 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.

e) 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. During the 2014 and 2013 years there were no additions to goodwill. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

Impairment testing is performed on an annual basis or more frequently if events or changes in circumstances indicate that goodwill may be impaired. If the fair value of the consolidated reporting unit is less than its book value (including goodwill), then goodwill is reduced to its implied fair value and the amount of the impairment is charged against earnings.

f) 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.

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

g) 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 routinely reviewed 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. The financial statement effects 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.

h) 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

Non-derivative financial instruments are comprised of cash, accounts receivable, accounts payable, dividends payable and long-term debt. The carrying amount of cash, accounts receivable, accounts payable and dividends payable approximate fair value. The fair value of long-term debt is disclosed in Note 16.

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.

i) 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").

j) 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 its Stock Option Plan and equity-settled RSU and PSU plans. The Company suspended the issuance of stock options effective in 2014.

k) 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.

l) 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.

m) Accounting Changes and Recent Pronouncements Issued

i. Changes in accounting policies for 2014

Effective January 1, 2014, Enerplus adopted the following Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"), which did not have a material impact on Enerplus' financial statements:

- ASU 2013-04, *Obligations resulting from Joint and Several Liability Arrangements*
- ASU 2013-05, *Parent's Accounting for Cumulative Translation Adjustments upon Derecognition of Subsidiaries*
- ASU 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists*

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 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity* – effective January 1, 2015
- ASU 2014-09, *Revenue from Contracts with Customers* – effective January 1, 2017
- 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

3) ACCOUNTS RECEIVABLE

($ thousands)	December 31, 2014	December 31, 2013
Accrued receivables	$ 136,949	$ 122,482
Accounts receivable – trade	41,618	36,034
Current income tax receivable	23,900	9,371
Allowance for doubtful accounts	(2,722)	(2,796)
Total accounts receivable	$ 199,745	$ 165,091

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

As at December 31, 2014 ($ thousands)	Cost	Accumulated Depletion and Depreciation	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

As at December 31, 2013 ($ thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties	$ 11,481,207	$ 9,061,063	$ 2,420,144
Other capital assets	89,818	68,608	21,210
Total PP&E	$ 11,571,025	$ 9,129,671	$ 2,441,354

5) IMPAIRMENT

($ thousands)	2014	2013	2012
Oil and natural gas properties	$ –	$ –	$ 781,099
Impairment expense	$ –	$ –	$ 781,099

Enerplus did not record any ceiling test impairments on its oil and natural gas properties in 2014 or 2013. During 2012, a non-cash impairment totaling $781.1 million was recorded in the United States cost centre due to high capital spending and a lower 12-month average trailing natural gas price during 2012. No impairments were recorded to the Canadian cost centre in 2012.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling test as at December 31, 2014, 2013 and 2012:

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
2014	$ 94.99	$ 1.09	$ 94.84	$ 4.30	$ 4.60
2013	96.94	1.03	93.19	3.67	3.16
2012	94.71	1.00	88.33	2.83	2.35

6) MARKETABLE SECURITIES

During the years ended December 31, 2014 and 2013, Enerplus sold certain publicly traded securities for proceeds of $13.3 million and $2.5 million, recognizing a loss of $2.8 million and a gain of $0.4 million, respectively. In connection with these sales, realized losses of $2.5 million and a gain of $0.3 million net of tax, respectively were reclassified from accumulated other comprehensive income to net income.

During the year ended December 31, 2012 Enerplus sold the majority of its unlisted securities for proceeds of $146.9 million and a gain of $86.5 million.

For the years ended December 31, 2014, 2013, and 2012 the change in fair value of publicly listed investments represented unrealized losses of $0.1 million, unrealized gains of $7.1 million, and unrealized losses of $10.1 million net of tax, respectively ($0.2 million loss, $8.2 million gain and $11.9 million loss before tax, respectively).

Realized gains are included in Other Income/(Expense) on the Consolidated Statements of Income/(Loss).

7) ACCOUNTS PAYABLE

($ thousands)	December 31, 2014	December 31, 2013
Accrued payables	$ 239,773	$ 262,117
Accounts payable – trade	111,233	115,040
Total accounts payable	$ 351,006	$ 377,157

8) DEBT

($ thousands)	December 31, 2014	December 31, 2013
Current:		
Senior notes	$ 98,933	$ 48,713
	98,933	48,713
Long-term:		
Bank credit facility	$ 79,917	$ 214,394
Senior notes	958,080	762,191
	1,037,997	976,585
Total debt	$ 1,136,930	$ 1,025,298

Bank Credit Facility

Enerplus has a senior unsecured, covenant-based, $1 billion bank credit facility that matures on October 31, 2017. Drawn fees range between 150 and 315 basis points over bankers' acceptance rates, with current drawn fees of 170 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, 2014 Enerplus had $79.9 million (December 31, 2013 – $214.4 million) drawn and was in compliance with all financial covenants under the facility. During 2014 a fee of $0.6 million (2013 – $0.7 million, 2012 – $0.7 million) was paid to extend the facility. These fees are considered debt issue costs and are capitalized on the Consolidated Balance Sheets. The weighted average interest rate on the facility for the year ended December 31, 2014 was 2.8% (December 31, 2013 – 2.6%).

Senior Notes

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 and 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	$ 232,020
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	23,202
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$355,000	411,836
June 18, 2009	June 18 and Dec 18	Bullet payment on June 18, 2015	6.37%	CDN$40,000	CDN$40,000	40,000
June 18, 2009	June 18 and Dec 18	Bullet payment on June 18, 2015	6.82%	US$40,000	US$40,000	46,403
June 18, 2009	June 18 and Dec 18	5 equal annual installments beginning June 18, 2017	7.97%	US$225,000	US$225,000	261,023
Oct 1, 2003	April 1 and Oct 1	5 equal annual installments beginning Oct 1, 2011	5.46%	US$54,000	US$10,800	12,529
				Total carrying value		$ 1,057,013
				Current portion		$ 98,933
				Long-term portion		$ 958,080

9) ASSET RETIREMENT OBLIGATION

At December 31, 2014 Enerplus estimated the present value of its asset retirement obligation to be $288.7 million (December 31, 2013 – $291.8 million) based on a total undiscounted liability of $730.9 million (December 31, 2013 – $720.6 million). The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.92% at December 31, 2014 (December 31, 2013 – 5.96%). Enerplus' asset retirement obligation expenditures are expected to be incurred over the next 65 years with the majority between 2029 and 2054. For the year-ended December 31, 2013, changes in estimate related to increases in estimated future abandonment and reclamation costs.

($ thousands)	December 31, 2014	December 31, 2013
Balance, beginning of year	$ 291,761	$ 256,102
Change in estimates	4,378	44,217
Property acquisition and development activity	1,778	1,454
Divestments	(4,313)	(8,362)
Settlements	(19,409)	(16,606)
Accretion expense	14,497	14,956
Balance, end of year	$ 288,692	$ 291,761

10) OIL AND NATURAL GAS SALES

($ thousands)	2014	2013	2012
Oil and natural gas sales	$ 1,849,312	$ 1,616,798	$ 1,365,542
Royalties(1)	(323,118)	(264,326)	(212,208)
Oil and natural gas sales, net of royalties	$ 1,526,194	$ 1,352,472	$ 1,153,334

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

11) GENERAL AND ADMINISTRATIVE EXPENSE

($ thousands)	2014	2013	2012
General and administrative expense	$ 83,493	$ 83,235	$ 78,341
Share-based compensation expense	21,548	27,025	15,503
General and administrative expense	$ 105,041	$ 110,260	$ 93,844

12) INTEREST EXPENSE

($ thousands)	2014	2013	2012
Realized:			
Interest on bank debt and senior notes	$ 62,240	$ 56,716	$ 53,074
Unrealized:			
Cross currency interest rate swap (gain)/loss	580	1,306	2,963
Interest rate swap (gain)/loss	–	(478)	(1,125)
Amortization of debt issue costs and senior note premium	968	793	(5)
Interest expense	$ 63,788	$ 58,337	$ 54,907

13) FOREIGN EXCHANGE

($ thousands)	2014	2013	2012
Realized:			
Foreign exchange (gain)/loss	$ 11,165	$ 17,596	$ 6,508
Unrealized:			
Translation of U.S. dollar debt and working capital (gain)/loss	68,202	19,747	(7,647)
Cross currency interest rate swap (gain)/loss	(16,128)	(19,920)	(15,118)
Foreign exchange swap (gain)/loss	(6,149)	(8,110)	(947)
Foreign exchange (gain)/loss	$ 57,090	$ 9,313	$ (17,204)

14) INCOME TAXES

Enerplus' provision for income tax is a follows:

($ thousands)	2014	2013	2012
Current Tax expense/(recovery)			
Canada	$ (543)	$ (621)	$ (2,074)
United States	5,541	8,510	3,722
Current tax expense/(recovery)	4,998	7,889	1,648
Deferred Tax expense/(recovery)			
Canada	$ 64,746	$ (21,166)	$ 17,720
United States	68,084	51,919	(292,359)
Deferred tax expense/(recovery)	132,830	30,753	(274,639)
Income tax expense/(recovery)	$ 137,828	$ 38,642	$ (272,991)

The deferred income tax recovery recognized in Other Comprehensive Income totaled $0.3 million for 2014 ($1.0 million expense in 2013, and $3.0 million recovery in 2012) related to marketable securities.

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

($ thousands)	2014	2013	2012
Income/(loss) before taxes			
Canada	$ 247,856	$ (74,946)	$ 220,259
United States	189,048	161,564	(763,947)
Total income/(loss) before taxes	$ 436,904	$ 86,618	$ (543,688)
Canadian statutory rate	25.35%	25.35%	25.32%
Expected income tax expense/(recovery)	$ 110,755	$ 21,958	$ (137,662)
Impact on taxes resulting from:			
Foreign tax rate differential	$ 11,242	$ 10,407	$ (106,858)
Statutory and other rate differences	(38)	(1,976)	(7,828)
Change in valuation allowance	8,007	(690)	(11,082)
Non-taxable capital (gains)/losses	8,318	4,884	(12,248)
Share-based compensation	2,636	2,335	2,574
Other	(3,092)	1,724	113
Income tax expense/(recovery)	$ 137,828	$ 38,642	$ (272,991)

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

($ thousands)	2014	2013
Deferred income tax liabilities		
Property, plant and equipment	$ (187,080)	$ (62,565)
Deferred financial assets and credits	(55,348)	–
Other liabilities	–	(9,343)
Total deferred income tax liabilities	(242,428)	(71,908)
Deferred income tax assets		
Tax loss carry-forwards and other credits	$ 610,177	$ 551,331
Asset retirement obligation	74,335	75,677
Deferred financial assets and credits	–	2,114
Other assets	15,879	8,317
Total deferred income tax assets	700,391	637,439
Less valuation allowance	(160,651)	(152,644)
Total deferred income tax assets, net	539,740	484,795
Net deferred income tax asset/(liability)	$ 297,312	$ 412,887

The net deferred income tax asset includes a current deferred income tax liability of $50.8 million (December 31, 2013 – asset of $48.5 million) and a long-term deferred income tax asset of $348.1 million (December 31, 2013 – $364.4 million).

Loss carry-forwards and tax credits that can be utilized in future years are as follows:

As at December 31 ($ thousands)	2014	Expiration Date
Canada		
Capital losses	$ 1,207,000	Indefinite
Non-capital losses	422,000	2028-2034
United States		
Net operating losses	592,000	2030-2034
Alternative minimum tax credits	113,000	Indefinite

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

For the years ended December 31 ($ thousands)	2014	2013	2012
Balance, beginning of year	$ 18,000	$ 18,500	$ 13,600
Increase/(decrease) for tax positions of prior years	2,700	(500)	4,900
Settlements	(3,700)	–	–
Balance, end of year	$ 17,000	$ 18,000	$ 18,500

If recognized, all of Enerplus' unrecognized tax benefits as at December 31, 2014 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	2004-2014
United States – Federal & State	2008-2014

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.

15) SHAREHOLDERS' EQUITY

a) Share Capital

	2014		2013		2012	
Authorized unlimited number of common shares Issued: (thousands)	**Shares**	**Amount**	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	202,758	$ 3,061,839	198,684	$ 2,997,682	181,159	$ 2,622,003
Issued for cash:						
Public offerings	–	–	–	–	14,709	330,618
Dividend Reinvestment Plan	–	–	–	–	955	19,150
Stock Option Plan	1,944	31,350	1,042	14,838	68	1,180
Non-cash:						
Stock Dividend Plan	1,030	21,835	3,032	46,211	1,793	23,612
Stock Option Plan	–	4,978	–	3,108	–	1,119
Balance, end of year	205,732	$ 3,120,002	202,758	$ 3,061,839	198,684	$ 2,997,682

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

b) Dividends

($ thousands)	2014	2013	2012
Cash dividends[(1)]	$ 199,263	$ 170,653	$ 277,948
Stock dividends	21,835	46,211	23,612
Dividends to shareholders	$ 221,098	$ 216,864	$ 301,560

(1) Includes DRIP of $19.2 million in 2012. The DRIP was discontinued in 2012 and has no impact on 2014 or 2013 cash dividends.

For the year ended December 31, 2014 Enerplus paid dividends of $1.08 per common share totaling $221.1 million (December 31, 2013 – $1.08 per share and $216.9 million, December 31, 2012 – $1.54 per share and $301.6 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)		2014		2013		2012
Cash:						
Long-term incentive plans (recovery)/expense	$	(1,220)	$	23,262	$	5,618
Non-Cash:						
Long-term incentive plans expense		9,349		–		–
Stock Option Plan expense		4,137		9,213		10,297
Equity swap (gain)/loss		9,282		(5,450)		(412)
Share-based compensation expense	$	21,548	$	27,025	$	15,503

(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, 2014:

	Cash-settled LTI Plans			Equity-settled LTI Plans		
For the year ended December 31, 2014 (thousands of units)	PSU	RSU	DSU	PSU	RSU	Total
Balance, beginning of year	650	821	99	–	–	1,570
Granted	–	8	47	560	849	1,464
Vested	(224)	(376)	(24)	–	–	(624)
Forfeited	(20)	(55)	–	(50)	(74)	(199)
Balance, end of year	406	398	122	510	775	2,211

Cash-settled LTI Plans

For the year ended December 31, 2014 the Company recorded a recovery for cash share-based compensation expense of $1.2 million (2013 – charges of $23.3 million, 2012 – charges of $5.6 million). For the year ended December 31, 2014, the Company made cash payments of $14.1 million related to its cash-settled plans (2013 – $11.1 million, 2012 – $14.0 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, 2014 ($ thousands, except for years)		PSU(1)		RSU		DSU		Total
Cumulative recognized share-based compensation expense	$	8,051	$	5,098	$	1,953	$	15,102
Unrecognized share-based compensation expense		2,698		987		–		3,685
Intrinsic value	$	10,749	$	6,085	$	1,953	$	18,787
Weighted-average remaining contractual term (years)		0.8		0.5		–		

(1) Includes estimated performance multipliers.

Equity-settled LTI Plans

For the year ended December 31, 2014 the Company recorded non-cash share-based compensation expense of $9.3 million. No non-cash amounts were recognized for the twelve months ended December 31, 2013 or December 31, 2012 with respect to equity-settled grants, as the ability to treasury settle was only effective as of March 2014.

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, 2014 ($ thousands, except for years)	**PSU[1]**	**RSU**	**Total**
Cumulative recognized share-based compensation expense	$ 2,239	$ 6,963	$ 9,202
Unrecognized share-based compensation expense	5,273	6,350	11,623
Fair value	$ 7,512	$ 13,313	$ 20,825
Weighted-average remaining contractual term (years)	2.0	1.5	

(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 year ended December 31, 2014. The following assumptions were used to arrive at the estimates of fair value during each of the respective reporting years:

Weighted average for the year	**December 31, 2014[2]**	**December 31, 2013**	**December 31, 2012**
Dividend yield[1]	N/A	8.0%	8.2%
Volatility[1]	N/A	27.80%	28.35%
Risk-free interest rate	N/A	1.51%	1.35%
Forfeiture rate	N/A	10.0%	10.0%
Expected life	N/A	4.5 years	4.5 years

(1) Reflects the expected dividend yield and volatility of Enerplus shares over the expected life of the option.
(2) The Company suspended stock option grants in 2014.

The following table summarizes the stock option plan activity for the year ended December 31, 2014:

Year ended December 31, 2014	**Number of Options** (thousands)	**Weighted Average Exercise Price**
Options outstanding, beginning of year	13,414	$ 18.65
Granted	–	–
Exercised	(1,944)	16.12
Forfeited	(641)	19.60
Expired	(461)	27.84
Options outstanding, end of year	10,368	$ 18.65
Options exercisable, end of year	5,748	$ 20.99

At December 31, 2014, 5,748,000 options were exercisable at a weighted average reduced exercise price of $20.99 with a weighted average remaining contractual term of 3.94 years, giving an aggregate intrinsic value of nil (December 31, 2013 – $5.2 million, December 31, 2012 – nil). The intrinsic value of options exercised during the year ended December 31, 2014 was $13.4 million (December 31, 2013 – $2.7 million, December 31, 2012 – $0.3 million).

At December 31, 2014 the total share-based compensation expense related to non-vested options not yet recognized was $1.1 million. The expense is expected to be recognized in net income over a weighted-average period of 0.8 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)	2014	2013	2012
Balance, beginning of year	$ 38,398	$ 32,293	$ 23,115
Stock Option Plan – exercised	(4,978)	(3,108)	(1,119)
Stock Option Plan – expensed	13,486	9,213	10,297
Balance, end of year	$ 46,906	$ 38,398	$ 32,293

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

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

(thousands, except per share amounts)	2014	2013	2012
Net income/(loss)	$ 299,076	$ 47,976	$ (270,697)
Weighted average shares outstanding – Basic	204,510	200,567	195,633
Dilutive impact of share-based compensation(1)	2,914	837	–
Weighted average shares outstanding – Diluted	207,424	201,404	195,633
Net income/(loss) per share			
Basic	1.46	0.24	(1.38)
Diluted	1.44	0.24	(1.38)

(1) For the year ended December 31, 2012 the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the loss per share.

16) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At December 31, 2014, 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.

Enerplus' portfolio of marketable securities consists of publicly traded investments. At December 31, 2014 the fair value of marketable securities was nil (December 31, 2013 – $13.4 million).

At December 31, 2014 senior notes included in long-term debt had a carrying value of $1,057.0 million and a fair value of $1,150.0 million (December 31, 2013 – $810.9 million and $837.8 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, 2014**	**December 31, 2013**	**December 31, 2012**	**Consolidated Statements of Income/(Loss) Presentation**
Interest Rate Swaps	$ –	$ 478	$ 1,125	Interest expense
Cross Currency Interest Rate Swap:				
Interest	(580)	(1,306)	(2,963)	Interest expense
Foreign Exchange	16,128	19,920	15,118	Foreign exchange
Foreign Exchange Derivatives	6,149	8,110	947	Foreign exchange
Electricity Swaps	(1,275)	758	(3,108)	Operating expense
Equity Swaps	(9,282)	5,450	412	General and administrative expense
Commodity Derivative Instruments:				
Oil	182,019	(65,504)	70,283	Commodity derivative
Gas	48,879	(2,994)	3,349	instruments
Total Gain/(Loss)	$ 242,038	$ (35,088)	$ 85,163	

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

($ thousands)	**2014**	**2013**	**2012**
Change in fair value gain/(loss)	$ 230,898	$ (68,498)	$ 73,632
Net realized cash gain/(loss)	3,475	26,628	18,363
Commodity derivative instruments gain/(loss)	$ 234,373	$ (41,870)	$ 91,995

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

	December 31, 2014				**December 31, 2013**		
	Assets		**Liabilities**		**Assets**		**Liabilities**
($ thousands)	**Current**	**Long-term**	**Current**	**Long-term**	**Current**	**Long-term**	**Current**
Cross Currency Interest Rate Swap:	$ –	$ –	$ –	$ –	$ –	$ –	$ 15,548
Foreign Exchange Derivatives	1,616	28,665	8,434	–	564	15,135	–
Electricity Swaps	–	–	1,368	–	–	–	95
Equity Swaps	–	–	1,024	2,396	1,723	4,139	–
Commodity Derivative Instruments:							
Oil	167,187	–	–	–	4,138	–	18,970
Gas	46,903	2,332	–	–	2,773	–	2,418
Total	$ 215,706	$ 30,997	$ 10,826	$ 2,396	$ 9,198	$ 19,274	$ 37,031

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 5, 2015:

Crude Oil Instruments:

Instrument Type	bbls/day	US$/bbl(1)
Jan 1, 2015 – Feb 28, 2015		
WTI Swap	15,500	93.58
WCS Differential Swap	4,000	(18.24)
WTI Purchased Call	4,000	93.00
WTI Sold Put	4,000	62.23
Mar 1, 2015 – Apr 30, 2015		
WTI Swap	17,500	88.85
WCS Differential Swap	4,000	(18.24)
WTI Purchased Call	4,000	93.00
WTI Sold Put	4,000	62.23
May 1, 2015 – Jun 30, 2015		
WTI Swap	15,500	93.58
WCS Differential Swap	4,000	(18.24)
WTI Purchased Call	4,000	93.00
WTI Sold Put	4,000	62.23
Jul 1, 2015 – Dec 31, 2015		
WTI Swap	8,000	93.86
WCS Differential Swap	3,000	(17.85)
WTI Purchased Call	4,000	93.00
WTI Sold Put	4,000	62.23

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

Natural Gas Instruments:

Instrument Type	MMcf/day	CDN$/Mcf
Jan 1, 2015 – Mar 31, 2015		
NYMEX Swap	80.0	4.25
NYMEX Collar – Purchased Put	30.0	4.53
NYMEX Collar – Sold Call	30.0	5.53
NYMEX Purchased Call	5.0	4.29
NYMEX Sold Put	5.0	3.25
NYMEX Sold Call	5.0	5.00
Apr 1, 2015 – Jun 30, 2015		
NYMEX Swap	90.0	4.21
NYMEX Purchased Call	5.0	4.29
NYMEX Sold Put	5.0	3.25
NYMEX Sold Call	5.0	5.00
Jul 1, 2015 – Sep 30, 2015		
NYMEX Swap	115.0	3.98
NYMEX Purchased Call	5.0	4.29
NYMEX Sold Put	5.0	3.25
NYMEX Sold Call	5.0	5.00
Oct 1, 2015 – Dec 31, 2015		
NYMEX Swap	95.0	4.04
NYMEX Purchased Call	5.0	4.29
NYMEX Sold Put	5.0	3.25
NYMEX Sold Call	5.0	5.00
Jan 1, 2016 – Dec 31, 2016		
NYMEX Swap	10.0	4.03

Electricity:

Instrument Type	MWh	CDN$/MWh
Jan 1, 2015 – Dec 31, 2015		
AESO Power Swap[1]	16.0	50.79
Jan 1, 2016 – Dec 31, 2016		
AESO Power Swap[1]	6.0	50.25

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

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations 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.

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.

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. The following contracts are outstanding at February 5, 2015:

Instrument Type[1]	Monthly Notional Amount (US$ millions)	Floor	Ceiling	Conditional Ceiling[2]
Jan 1, 2015 – Dec 31, 2015	24.0	1.1088	1.1845	1.1263

(1) Transactions with a common term have been aggregated and presented at average USD/CDN foreign exchange rates.
(2) If the USD/CDN average monthly rate settles above the ceiling rate the settlement amount is determined based on the conditional ceiling.

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 matures in October 2015 in conjunction with the final principal repayment on the US$54.0 million senior notes.

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.

Interest Rate Risk:

At December 31, 2014, approximately 93% of Enerplus' debt was based on fixed interest rates and 7% was based on floating interest rates. At December 31, 2014 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 15. Enerplus has entered into various equity swaps maturing between 2015 and 2016 and has effectively fixed the future settlement cost on 950,000 shares at a weighted average price of $14.92 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, 2014 approximately 71% of Enerplus' marketing receivables were with companies considered investment grade.

At December 31, 2014 approximately $3.2 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, 2014 was $2.7 million (December 31, 2013 – $2.8 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.

17) COMMITMENTS, CONTINGENCIES AND GUARANTEES

a) Commitments

Enerplus has the following minimum annual commitments at December 31, 2014:

		Minimum Annual Commitment Each Year					
($ thousands)	Total	2015	2016	2017	2018	2019	Thereafter
Bank credit facility	$ 79,917	$ –	$ –	$ 79,917	$ –	$ –	$ –
Senior notes[3]	1,057,013	98,933	–	52,205	52,205	82,204	771,466
Transportation commitments	165,455	39,721	29,617	18,765	9,377	7,451	60,524
Processing commitments	58,830	11,388	11,309	10,788	9,300	5,713	10,332
Drilling and completions	19,309	19,309	–	–	–	–	–
Office leases	121,882	12,075	12,351	12,449	12,413	11,302	61,292
Total commitments[1][2]	$ 1,502,406	$181,426	$ 53,277	$174,124	$ 83,295	$106,670	$ 903,614

(1) Crown and surface royalties, 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.
(2) US$ commitments have been converted to CDN$ using the December 31, 2014 foreign exchange rate of 1.1601.
(3) Interest payments have not been included.

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.

18) GEOGRAPHICAL INFORMATION

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
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
Goodwill	451,121	158,854	609,975

As at and for the year ended December 31, 2012 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales	$ 707,985	$ 445,349	$ 1,153,334
Property, plant and equipment	1,323,850	1,013,945	2,337,795
Goodwill	451,121	148,595	599,716

19) SUPPLEMENTAL INFORMATION

a) Change in Non-Cash Operating Working Capital

($ thousands)	December 31, 2014	December 31, 2013	December 31, 2012
Accounts receivable	$ (8,392)	$ (6,935)	$ (34,384)
Other current assets	(6,777)	(1,156)	4,007
Accounts payable	(37,245)	36,942	(58,552)
	$ (52,414)	$ 28,851	$ (88,929)

b) Supplementary Cash Flow Information

($ thousands)	December 31, 2014	December 31, 2013	December 31, 2012
Income taxes paid	$ 18,087	$ 4,448	$ 17,946
Interest paid	$ 58,416	$ 55,957	$ 49,826

20) SUBSEQUENT EVENT

Subsequent to December 31, 2014 Enerplus entered into agreements to dispose of Canadian crude oil properties for proceeds (before closing adjustments) of approximately $182 million, subject to customary closing conditions.

Subsequent to December 31, 2014 Enerplus' Board of Directors approved a reduction in its monthly dividend from $0.09 per share to $0.05 per share, effective with the April dividend.

5 YEAR DETAILED STATISTICAL REVIEW

	2014	2013	2012	2011	2010[12]
Daily Production[1]					
Crude oil (bbls/day)	40,208	38,250	36,509	30,181	31,135
NGLs (bbls/day)	3,565	3,472	3,627	3,306	3,889
Natural gas (Mcf/day)	356,142	288,423	251,773	251,068	288,692
BOE per day	103,130	89,793	82,098	75,332	83,139
Drilling Activity (net wells)	88	62	75	107	225
Average Benchmark Pricing					
WTI crude oil (US$ per bbl)	$ 93.00	$ 97.97	$ 94.21	$ 95.12	$ 79.53
AECO natural gas – monthly (per Mcf)	4.42	3.16	2.40	3.68	4.13
NYMEX natural gas – last day(US$ per Mcf)	4.41	3.65	2.79	4.04	4.39
US/CDN exchange Rate	1.10	1.03	1.00	0.99	1.03
Realized Pricing					
Crude oil (per bbl)	$ 84.53	$ 83.99	$ 78.19	$ 83.48	$ 70.38
Natural gas liquids (per bbl)	49.89	52.25	53.01	64.99	51.41
Natural gas (per Mcf)	3.81	3.26	2.39	3.72	4.05
Average realized price[2] (per BOE)	47.61	48.11	44.56	48.85	42.85

($ thousands, except per share amounts)	2014	2013	2012	2011	2010[12]
Financial					
Oil and natural gas sales[2]	$1,792,097	$1,576,878	$1,338,973	$1,343,079	$1,300,181
Funds flow	859,020	754,233	644,523	574,401	728,968
Cash flow from operating activities	787,197	766,478	535,689	624,232	696,183
Cash and stock dividends to shareholders	221,098	216,864	301,560	388,904	384,127
Per share	1.08	1.08	1.62	2.16	2.16
Capital spending	811,026	681,437	853,435	866,504	536,436
Property and land acquisitions	18,491	244,837	185,337	255,209	1,012,272
Property Divestitures	203,576	365,135	275,771	641,190	871,458
Total net capital expenditures[3]	632,883	567,607	774,862	491,786	681,254
Total assets	4,082,297	3,681,799	3,856,083	5,723,312	5,489,181
Total debt, net of current portion of long-term debt and cash	1,035,961	973,595	1,018,799	901,465	724,031
Adjusted payout ratio[4]	118%	114%	174%	212%	123%
Net debt/funds flow ratio	1.3x	1.4x	1.7x	1.6x	1.0x
Oil and Gas Economics					
Net royalty rate	23%	21%	20%	18%	17%
Average realized price[2]	$ 47.61	$ 48.11	$ 44.56	$ 48.85	$ 42.85
Commodity derivative instruments[6]	0.09	0.81	0.61	(1.21)	1.64
Average realized price[5]	47.70	48.92	45.17	47.64	44.49
Net royalty & production tax expense	10.75	10.21	8.95	8.92	7.36
Operating expense[6]	10.40	10.50	10.51	10.30	9.66
Operating netback, after hedging	26.55	28.21	25.71	28.42	27.47
General and administrative expense[6]	2.19	3.25	2.79	2.99	2.76
Interest, foreign exchange and other expenses[6]	1.42	1.71	1.42	1.59	1.69
Taxes	0.12	0.24	0.05	2.95	(1.00)
Funds flow	$ 22.82	$ 23.01	$ 21.45	$ 20.83	$ 24.02

($ thousands, except per share amounts)	2014	2013	2012	2011	2010[12]
Reserves					
Proved Reserves[7]					
Crude oil (Mbbls)	127,007	118,611	124,759	116,664	109,706
NGLs (Mbbls)	8,137	8,967	9,236	9,215	8,610
Natural gas (MMcf)	331,709	409,830	413,906	476,887	554,090
Shale gas (MMcf)	564,583	411,431	146,127	92,682	52,225
MBOE	284,525	264,455	227,335	220,807	219,369
Probable Reserves[7]					
Crude oil (Mbbls)	73,424	73,635	66,913	54,497	40,147
NGLs (Mbbls)	4,662	5,757	5,387	4,411	2,966
Natural gas (MMcf)	124,721	183,744	198,727	192,363	198,097
Shale gas (MMcf)	275,357	189,430	78,373	60,861	64,437
MBOE	144,766	141,587	118,483	101,112	86,868
Proved Plus Probable Reserves[7]					
Crude oil (Mbbls)	200,431	192,246	191,672	171,161	149,853
NGLs (Mbbls)	12,798	14,723	14,623	13,626	11,576
Natural gas (MMcf)	456,430	593,574	612,634	669,250	752,187
Shale gas (MMcf)	839,940	600,861	224,500	153,543	116,662
MBOE	429,291	406,042	345,817	321,919	306,237
Reserves Life Index[8]					
Proved (years)	7.8	7.6	7.8	7.7	8.2
Proved plus probable (years)	10.7	10.8	10.9	9.8	10.7
Trading Information[9]					
Canadian trading summary[10]					
High	$ 27.05	$ 19.96	$ 26.94	$ 32.83	$ 31.85
Low	9.02	12.26	11.53	23.00	18.22
Close	11.19	19.30	12.90	25.85	30.67
Volume	360,805	214,057	270,710	180,917	127,386
U.S. trading summary[11]					
High	$ 25.37	$ 18.79	$ 26.54	$ 33.29	$ 31.83
Low	7.75	12.03	11.35	21.65	13.76
Close	9.60	18.18	12.96	25.32	30.84
Volume	203,965	192,733	386,690	225,858	168,979
Weighted average number of shares outstanding (basic)	204,510	200,567	195,633	179,889	175,736
Number of shares outstanding at December 31	205,732	202,758	198,684	181,159	176,946

(1) Production is on a company interest basis.
(2) Net of transportation but before 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) Does not include non-cash portion of expense.
(7) 2014 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.
(8) 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.
(9) 2010 – Trust Units trading information. All other years – share trading information. All shares are in thousands.
(10) TSX data 2010, Canadian composite trading data including TSX thereafter. Volumes are in thousands.
(11) NYSE data 2010, U.S. composite trading data including NYSE thereafter. Volumes are in thousands.
(12) 2010 comparatives restated in accordance with IFRS. All other data prepared in accordance with U.S. GAAP.

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 89% of the total proved plus probable value (before tax, discounted at 10%, using forecast prices and costs) of our reserves at December 31, 2014. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated approximately 71% of our Canadian 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 29% of our Canadian properties. Netherland, Sewell & Associates, Inc. ("NSAI") evaluated the reserves of our U.S. properties in Pennsylvania and West Virginia.

The following reserves information sets out our gross reserves volumes at December 31, 2014 by production type and reserves category under McDaniel's 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, 2014 were based upon forecast crude oil and natural gas pricing assumptions prepared by McDaniel as of January 1, 2015. 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.

McDaniel January 2015 Forecast Price Assumptions

	WTI(1) Crude Oil US$/bbl	Light Crude Oil Edmonton(2) CDN$/bbl	Alberta Heavy Crude Oil(3) 12° API CDN$/bbl	Sask Cromer Medium CDN$/bbl	U.S. Henry Hub Gas Price US$/MMBtu	Natural Gas Alberta Spot @ AECO CDN$/MMBtu	Exchange Rate US$/CDN$
2015	65.00	68.60	51.10	64.50	3.30	3.50	0.86
2016	75.00	83.20	62.00	78.20	3.80	4.00	0.86
2017	80.00	88.90	66.20	83.60	4.05	4.25	0.86
2018	84.90	94.60	70.50	88.90	4.30	4.50	0.86
2019	89.30	99.60	74.20	93.60	4.55	4.70	0.86
Thereafter	(4)	(4)	(4)	(4)	(5)	(5)	0.86

(1) West Texas Intermediate at Cushing Oklahoma 40 degree API, 0.5% sulphur content crude.
(2) Edmonton Light Sweet 40 degree API, 0.3% sulphur content crude.
(3) After deducting blending costs to reach pipeline quality.
(4) Escalation is approximately 5% in 2020 and approximately 2% per year thereafter.
(5) Escalation is approximately 6.5% in 2020, declining to 3.5% in 2024 and approximately 2% per year thereafter.

Reserves Summary

Enerplus' 2P reserves increased by 28.6 million BOE to 429.3 million BOE at year-end 2014, up from 400.7 million at year-end 2013. The majority of reserves additions, including technical revisions and economic factors and after acquisitions and divestitures were from our Fort Berthold and Marcellus assets. These assets now represent 61% of total 2P reserves, an increase of 10% from 2013. Proved reserves as a percentage of total 2P reserves are 66%, a 1% increase from 2013.

Reserves Summary	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Gross							
Proved producing	68,361	26,858	95,219	6,149	268,390	386,620	210,536
Proved developed non-producing	5,509	13	5,522	456	9,840	70,010	19,286
Proved undeveloped	21,615	4,651	26,266	1,532	53,479	107,952	54,704
Total proved	95,485	31,522	127,007	8,137	331,709	564,583	284,525
Total probable	61,808	11,616	73,424	4,662	124,721	275,357	144,766
Proved plus probable	**157,293**	**43,138**	**200,431**	**12,798**	**456,430**	**839,940**	**429,291**
Net							
Proved producing	56,907	21,454	78,361	4,698	239,194	309,371	174,486
Proved developed non-producing	4,378	12	4,390	352	7,759	56,014	15,370
Proved undeveloped	17,522	3,532	21,054	1,208	48,538	86,384	44,748
Total proved	78,806	24,998	103,804	6,256	295,491	451,770	234,604
Total probable	49,917	8,966	58,883	3,636	109,933	220,305	117,558
Proved plus probable	**128,723**	**33,964**	**162,687**	**9,892**	**405,424**	**672,075**	**352,161**

Reserve Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a gross basis, from December 31, 2013 to December 31, 2014.

PROVED RESERVES – GROSS VOLUMES (FORECAST PRICES)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at December 31, 2013	29,163	30,806	59,969	6,203	336,199	–	122,204
Acquisitions	–	–	–	–	–	–	–
Dispositions	(24)	–	(24)	(1,425)	(41,034)	–	(8,288)
Discoveries	–	–	–	–	–	–	–
Extensions and Improved Recovery	612	2,265	2,877	533	28,208	–	8,112
Economic Factors	200	–	200	(5)	(8,200)	–	(1,171)
Technical Revisions	(451)	1,587	1,136	(114)	8,604	–	2,456
Production	(2,930)	(3,136)	(6,066)	(860)	(53,116)	–	(15,778)
Proved Reserves at December 31, 2014	26,571	31,522	58,093	4,333	270,661	–	107,535

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at December 31, 2013	58,526	–	58,526	2,529	54,081	411,431	138,640
Acquisitions	64	–	64	4	36	–	74
Dispositions	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–
Extensions and Improved Recovery	8,243	–	8,243	586	4,879	164,065	36,986
Economic Factors	7	–	7	–	13	–	9
Technical Revisions	10,651	–	10,651	1,078	8,067	57,767	22,702
Production	(8,577)	–	(8,577)	(393)	(6,028)	(68,681)	(21,422)
Proved Reserves at December 31, 2014	68,914	–	68,914	3,804	61,048	564,583	176,990

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at December 31, 2013	87,689	30,806	118,495	8,732	390,279	411,431	260,844
Acquisitions	64	–	64	4	36	–	74
Dispositions	(24)	–	(24)	(1,425)	(41,034)	–	(8,288)
Discoveries	–	–	–	–	–	–	–
Extensions and Improved Recovery	8,855	2,265	11,120	1,119	33,087	164,065	44,717
Economic Factors	207	–	207	(5)	(8,187)	–	(1,162)
Technical Revisions	10,200	1,587	11,787	964	16,671	57,767	25,539
Production	(11,507)	(3,136)	(14,643)	(1,253)	(59,144)	(68,681)	(37,199)
Proved Reserves at December 31, 2014	95,485	31,522	127,007	8,137	331,709	564,583	284,525

PROBABLE RESERVES – GROSS VOLUMES (FORECAST PRICES)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at December 31, 2013	9,662	11,260	20,922	2,523	142,103	–	47,129
Acquisitions	–	–	–	–	–	–	–
Dispositions	(10)	–	(10)	(469)	(13,075)	–	(2,658)
Discoveries	–	–	–	–	–	–	–
Extensions and Improved Recovery	258	1,884	2,142	165	12,484	–	4,387
Economic Factors	–	–	–	(566)	(20,847)	–	(4,041)
Technical Revisions	(733)	(1,528)	(2,261)	(323)	(31,307)	–	(7,801)
Production	–	–	–	–	–	–	–
Probable Reserves at December 31, 2014	9,177	11,616	20,793	1,330	89,359	–	37,016

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at December 31, 2013	52,678	–	52,678	3,106	32,342	189,430	92,746
Acquisitions	995	–	995	67	557	–	1,154
Dispositions	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–
Extensions and Improved Recovery	4,157	–	4,157	291	2,421	38,835	11,324
Economic Factors	–	–	–	–	–	–	–
Technical Revisions	(5,199)	–	(5,199)	(132)	42	47,092	2,525
Production	–	–	–	–	–	–	–
Probable Reserves at December 31, 2014	52,631	–	52,631	3,332	35,362	275,357	107,749

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at December 31, 2013	62,340	11,260	73,600	5,629	174,446	189,430	139,875
Acquisitions	995	–	995	67	557	–	1,154
Dispositions	(10)	–	(10)	(469)	(13,075)	–	(2,658)
Discoveries	–	–	–	–	–	–	–
Extensions and Improved Recovery	4,415	1,884	6,299	455	14,905	38,835	16,091
Economic Factors	–	–	–	(566)	(20,847)	–	(4,040)
Technical Revisions	(5,932)	(1,528)	(7,460)	(455)	(31,265)	47,092	(5,657)
Production	–	–	–	–	–	–	–
Probable Reserves at December 31, 2014	61,808	11,616	73,424	4,662	124,721	275,357	144,766

PROVED PLUS PROBABLE RESERVES – GROSS VOLUMES (FORECAST PRICES)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at December 31, 2013	38,825	42,066	80,891	8,726	478,302	–	169,334
Acquisitions	–	–	–	–	–	–	–
Dispositions	(34)	–	(34)	(1,894)	(54,108)	–	(10,946)
Discoveries	–	–	–	–	–	–	–
Extensions and Improved Recovery	870	4,149	5,019	698	40,692	–	12,499
Economic Factors	200	–	200	(571)	(29,047)	–	(5,212)
Technical Revisions	(1,183)	59	(1,124)	(437)	(22,703)	–	(5,345)
Production	(2,930)	(3,136)	(6,066)	(860)	(53,116)	–	(15,778)
Proved Plus Probable Reserves at December 31, 2014	35,748	43,138	78,886	5,662	360,020	–	144,552

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at December 31, 2013	111,204	–	111,204	5,635	86,423	600,861	231,386
Acquisitions	1,059	–	1,059	71	593	–	1,229
Dispositions	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–
Extensions and Improved Recovery	12,400	–	12,400	876	7,301	202,900	48,310
Economic Factors	7	–	7	–	13	–	9
Technical Revisions	5,452	–	5,452	946	8,109	104,859	25,227
Production	(8,577)	–	(8,577)	(393)	(6,028)	(68,681)	(21,422)
Proved Plus Probable Reserves at December 31, 2014	121,545	–	121,545	7,136	96,410	839,940	284,739

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at December 31, 2013	150,029	42,066	192,095	14,360	564,725	600,861	400,720
Acquisitions	1,059	–	1,059	71	593	–	1,229
Dispositions	(34)	–	(34)	(1,894)	(54,108)	–	(10,946)
Discoveries	–	–	–	–	–	–	–
Extensions and Improved Recovery	13,271	4,149	17,420	1,574	47,993	202,900	60,809
Economic Factors	207	–	207	(571)	(29,034)	–	(5,203)
Technical Revisions	4,268	59	4,327	510	(14,594)	104,859	19,882
Production	(11,507)	(3,136)	(14,643)	(1,253)	(59,144)	(68,681)	(37,199)
Proved Plus Probable Reserves at December 31, 2014	157,293	43,138	200,431	12,798	456,430	839,940	429,291

FUTURE DEVELOPMENT CAPITAL

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 U.S. FDC has increased as a result of the change in the estimated US$/CDN$ exchange rate and an increase in the estimated development cost per well in Fort Berthold, this was offset by a decrease in the number of undeveloped drilling locations at Fort Berthold, Marcellus and Canadian gas properties, resulting in an overall decrease in 2014 FDC compared to 2013.

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:

Future Development Capital ($ millions)	**Proved Reserves**	**Proved Plus Probable Reserves**
2015	429	563
2016	248	439
2017	227	423
2018	40	346
2019	29	133
Remainder	33	32
Total FDC Undiscounted	1,006	1,936
Total FDC Discounted at 10%	873	1,606

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

($ millions except for per BOE amounts)	2014	2013	2012	3 Year
Proved Plus Probable Reserves				
Finding & Development Costs				
Capital Expenditures	$ 811.0	$ 681.4	$ 852.8	$ 2,345.3
Net change in Future Development Capital	$ (71.3)	$ 200.0	$ 534.6	$ 663.3
Gross Reserves additions (MMBOE)	75.5	78.1	57.3	210.9
F&D costs ($/BOE)	$ 9.80	$ 11.28	$ 24.21	$ 14.26
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$ 625.9	$ 561.1	$ 726.4	$ 1,913.5
Net change in Future Development Capital	$ (59.2)	$ 216.6	$ 509.1	$ 666.5
Gross Reserves additions (MMBOE)	65.8	93.0	53.9	212.7
FD&A costs ($/BOE)	$ 8.62	$ 8.36	$ 22.92	$ 12.13
Proved Reserves				
Finding & Development Costs				
Capital Expenditures	$ 811.0	$ 681.4	$ 852.8	$ 2,345.3
Net change in Future Development Capital	$ 13.8	$ (106.4)	$ 248.3	$ 155.7
Gross Reserves additions (MMBOE)	69.1	57.1	38.4	164.6
F&D costs ($/BOE)	$ 11.94	$ 10.08	$ 28.67	$ 15.20
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$ 625.9	$ 561.1	$ 726.4	$ 1,913.5
Net change in Future Development Capital	$ 4.9	$ (112.8)	$ 241.3	$ 133.4
Gross Reserves additions (MMBOE)	60.9	69.9	36.6	167.4
FD&A costs ($/BOE)	$ 10.36	$ 6.41	$ 26.44	$ 12.23

ECONOMIC, BEST ESTIMATE 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, 2014. These contingent resources are economic using McDaniel's January 1, 2015 forecast commodity prices and use established technologies.

The evaluations of contingent resources associated with the Wilrich 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. The contingent resources assessment associated with a portion of our waterflood properties was completed internally by qualified reserves evaluators.

Contingent Resources	"Best Estimate" Contingent Resources	Contingent Resources Net Drilling Locations
Canada		
Crude oil – IOR/EOR on a portion of waterfloods (MMBOE)	59.3	106
Natural gas – Wilrich (BcfGE)	242.6	49
Total Canada (MMBOE)	**99.7**	**155**
United States		
Crude oil and NGLs – Bakken/Three Forks oil wells Fort Berthold (MMBOE)	114.5	186
Natural gas – Marcellus (Bcf)	1407.9	144
Total United States (MMBOE)	**349.2**	**330**
Total Company (MMBOE)	**448.9**	**485**

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 prices for our portfolio of crude oil and also a decrease in the prices of natural gas at AECO and Henry Hub when compared to the price assumptions used at December 31, 2013. As a result, despite a 7% increase in our 2P reserves at December 31, 2014, the estimated before tax NPV using a 10% discount rate decreased by 12%.

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

Reserves at December 31, 2014, ($ Millions, discounted at)	**0%**	**5%**	**10%**	**15%**
Proved developed producing	5,276	3,594	2,745	2,241
Proved developed non-producing	390	206	129	88
Proved undeveloped	1,256	512	208	54
Total Proved	6,923	4,312	3,082	2,383
Probable	5,011	2,240	1,274	822
Total Proved Plus Probable Reserves (before tax)	11,934	6,552	4,356	3,205

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, 2014, the best estimate of economic contingent resources contained within our leases was 448.9 million BOE. As we execute our capital programs, we expect to convert contingent resources to reserves which could result in a doubling of 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.

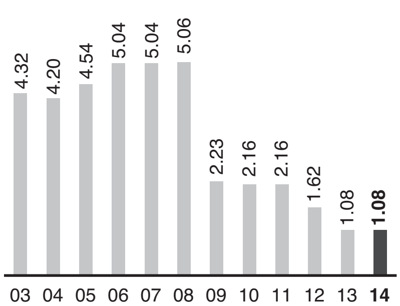
Net Asset Value (Forecast Prices and Costs at December 31, 2014)

($ millions except share amounts, discounted at)	0%	5%	10%	15%
Total net present value of proved plus probable reserves (before tax)	$11,934	$6,552	$4,356	$3,205
Undeveloped acreage (2014 Year End)(1)	296	296	296	296
Asset retirement obligations(2)	(477)	(245)	(52)	(34)
Long-term debt, including current portion (net of cash)	(1,135)	(1,135)	(1,135)	(1,135)
Net working capital(4)	(7)	(7)	(7)	(7)
Net Asset Value	**$10,611**	**$5,461**	**$3,458**	**$2,325**
Net Asset Value per Share(3)	**$51.58**	**$26.54**	**$16.81**	**$11.30**

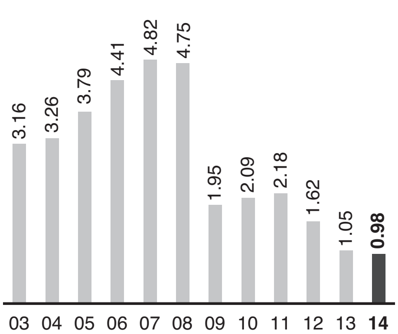
(1) Canadian acreage in Stacked Mannville, Cardium and validated Duvernay is carried at acquisition cost. Acreage in the U.S. that is prospective is carried at historical acquisition cost. All other acreage is valued at a nominal value of $50/acre.
(2) Asset retirement obligations ("ARO") do not equal the amount on the balance sheet ($288.7 million) as the balance sheet amount uses a 5.92% discount rate and a portion of the ARO costs are already reflected in the present value of reserves computed by the independent engineers.
(3) Based on 205,732,000 shares outstanding as at December 31, 2014.
(4) Net working capital includes deferred income tax assets and deferred financial assets and credits.

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.

Best Estimate of Economic Contingent Resources An estimate with an equal likelihood that the actual remaining quantities of contingent resources recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least 50% probability that the quantities actually recovered will equal or exceed the best estimate. Economic contingent resources are those resources that are economically recoverable based on McDaniel's January 1, 2015 forecast commodity prices.

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.

F&D Costs Finding and development costs. Calculated as total capital expenditures, exclusive of acquisitions or divestments, and including changes in future development capital, divided by the applicable reserves additions (proved and/or proved plus probable). It is a measure of the effectiveness of a company's capital program.

FD&A Costs Finding, development and acquisition costs. Calculated as total capital expenditures and net acquisitions, including changes in future development capital, divided by reserves additions (proved and/or proved plus probable). It is a measure of a company's ability to add reserves in a cost effective manner.

Future Development Capital (FDC) Future Development Capital 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.

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

Payout Ratio Calculated as dividends to shareholders (net of stock dividends and DRIP proceeds) divided by funds flow.

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(12)
Corporate Director
Houston, Texas

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

Edwin V. Dodge(11)
Corporate Director
Vancouver, British Columbia

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

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

James B. Fraser(7)(11)
Corporate Director
Polson, Montana

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

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

Donald J. Nelson(3)(9)
President
Fairway Resources, Inc.
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

CHAIRMAN EMERITUS

Douglas R. Martin(1)
Calgary, Alberta

(1) Chairman Emeritus is an honorary title and, as such, Mr. Martin does not attend Board meetings nor does he receive any compensation.

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas
President & Chief Executive Officer

Ray J. Daniels
Senior Vice President, Operations

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

Robert J. Waters
Senior Vice President & Chief Financial Officer

Jo-Anne M. Caza
Vice President, Corporate & Investor Relations

Jodine J. Jenson Labrie
Vice President, Finance

Robert A. Kehrig
Vice President, Business Development & New Plays

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

Edward L. McLaughlin
President, Enerplus (USA) Corporation

Lisa M. Ower
Vice President, Human Resources

P. Scott Walsh
Vice President, Information & Corporate Services

Kenneth W. Young
Vice President, Land & Operations Services

Michael R. Politeski
Treasurer & Corporate Controller

CORPORATE INFORMATION

Operating Companies Owned by Enerplus Corporation

Enerplus Resources (USA) Corporation

Legal Counsel
Blake, Cassels & Graydon LLP
Calgary, Alberta

Auditors
Deloitte LLP
Calgary, Alberta

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

U.S. Co-Transfer Agent
Computershare Trust Company, N.A.
Golden, Colorado

Independent Reserves Engineers
McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

Stock Exchange Listings and Trading Symbols
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New York Stock Exchange: ERF

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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 8, 2015
10:00 am, MT
The Telus Convention Centre
Glen 205
120 – 9th Avenue SE
Calgary, Alberta

Why invest in Enerplus?

Enerplus is a North American energy producer with a portfolio of high quality oil and gas assets in resource plays that offer significant organic growth potential. We are focused on creating value for our investors through the execution of a disciplined capital investment strategy that supports the successful development of our properties, and a monthly dividend to shareholders. We are a responsible developer of resources that strives to provide investors with a competitive return comprised of both growth and income.

ERF LISTED ON TMX Toronto Stock Exchange

ERF LISTED NYSE

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