STRENGTHENED ENERGIZED DISCIPLINED FOCUSED

2013

enerPLUS

2013 FINANCIAL SUMMARY

In 2013, we consistently met or exceeded our guidance targets while delivering sustainable, profitable growth to our investors.

58% Canadian total return

9% Growth in annual average production

17% growth in 2P reserves

17% Increase in funds flow

284% production replacement

Contents

2013 FINANCIAL SUMMARY

Selected Financial and Operating Results

SELECTED FINANCIAL RESULTS	Three months ended December 31, 2013	Three months ended December 31, 2012	Twelve months ended December 31, 2013	Twelve months ended December 31, 2012
Financial (000's)				
Funds Flow	$ 180,741	$ 200,411	$ 754,233	$ 644,523
Cash and Stock Dividends	54,665	53,572	216,864	301,560
Net Income	29,626	34,637	47,976	(270,697)
Debt Outstanding – net of cash	1,022,308	1,064,365	1,022,308	1,064,365
Capital Spending	223,035	160,934	681,437	853,455
Property and Land Acquisitions	173,387	121,391	244,837	185,337
Property Divestments	168,050	220,135	365,135	275,771
Debt to Trailing 12-Month Funds Flow	1.4x	1.7x	1.4x	1.7x
Financial per Weighted Average Shares Outstanding				
Funds Flow	$ 0.89	$ 1.01	$ 3.76	$ 3.29
Net Income	0.15	0.17	0.24	(1.38)
Weighted Average Number of Shares Outstanding (000's)	202,257	198,256	200,567	195,633
Selected Financial Results per BOE[(1)(2)]				
Oil & Natural Gas Sales[(3)]	$ 43.79	$ 45.86	$ 48.11	$ 44.56
Royalties	(7.46)	(7.28)	(8.06)	(7.06)
Production Taxes	(2.07)	(2.26)	(2.15)	(1.89)
Commodity Derivative Instruments	1.90	2.04	0.81	0.61
Operating Costs	(10.46)	(9.14)	(10.50)	(10.51)
General and Administrative	(2.28)	(2.34)	(2.54)	(2.61)
Share-Based Compensation	(1.06)	(0.03)	(0.71)	(0.18)
Interest and Other Expenses	(1.51)	(1.45)	(1.71)	(1.42)
Taxes	0.01	0.08	(0.24)	(0.05)
Funds Flow	$ 20.86	$ 25.48	$ 23.01	$ 21.45

SELECTED OPERATING RESULTS	Three months ended December 31, 2013	Three months ended December 31, 2012	Twelve months ended December 31, 2013	Twelve months ended December 31, 2012
Average Daily Production[(2)]				
Crude oil (bbls/day)	37,731	38,597	38,250	36,509
NGLs (bbls/day)	3,813	3,576	3,472	3,627
Natural gas (Mcf/day)	315,739	259,904	288,423	251,773
Total (BOE/day)	94,167	85,490	89,793	82,098
% Crude Oil & Natural Gas Liquids	44%	49%	46%	49%
Average Selling Price[(2)(3)]				
Crude oil (per bbl)	$ 77.77	$ 76.75	$ 83.99	$ 78.19
NGLs (per bbl)	54.26	47.31	52.25	53.01
Natural gas (per Mcf)	3.26	3.01	3.26	2.39
Net Wells drilled	18	11	62	75

(1) Non-cash amounts have been excluded.
(2) Based on Company interest production volumes.
(3) Net of oil and gas transportation costs, but before royalties and the effects of commodity derivative instruments.

Average Benchmark Pricing	Three months ended December 31, 2013	Three months ended December 31, 2012	Twelve months ended December 31, 2013	Twelve months ended December 31, 2012
WTI crude oil (US$/bbl)	$ 97.46	$ 88.18	$ 97.97	$ 94.21
AECO – monthly index (CDN$/Mcf)	3.16	3.06	3.16	2.40
AECO – daily index (CDN$/Mcf)	3.53	3.22	3.17	2.39
NYMEX – monthly NX3 index (US$/Mcf)	3.63	3.36	3.67	2.80
USD/CDN exchange rate	1.05	0.99	1.03	1.00

Share Trading Summary For the twelve months ended December 31, 2013	CDN* – ERF (CDN$)	U.S.** – ERF (US$)
High	$ 19.96	$ 18.79
Low	$ 12.26	$ 12.03
Close	$ 19.30	$ 18.18

* TSX and other Canadian trading data combined.

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

2013 Dividends per Share	CDN$	US$(1)
First Quarter Total	$ 0.27	$ 0.27
Second Quarter Total	$ 0.27	$ 0.26
Third Quarter Total	$ 0.27	$ 0.26
Fourth Quarter Total	$ 0.27	$ 0.26
Total Year-to-Date	$ 1.08	$ 1.05

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

2013 HIGHLIGHTS

RESERVES/RESOURCES

- Proved plus probable company interest ("2P") reserves grew by over 17% to 406 MMBOE. We added 78 MMBOE of 2P reserves through our development programs, including technical and economic revisions, replacing 238% of 2013 annual production. Approximately 30% of the reserve additions were from crude oil. On a per share basis, 2P reserves increased by 15% year-over-year.
- Added a total of 93 MMBOE of 2P reserves, including technical and economic revisions and net acquisition and development activity, replacing 284% of production in 2013. 83% of the total reserve additions were from natural gas.
- 2P finding and development ("F&D") costs including future development capital ("FDC") decreased by over 50% to $11.28 per BOE. This represents a recycle ratio of 2.4 times based upon an estimated operating netback of $27.40 per BOE in 2013.
- 2P finding, development and acquisition ("FD&A") costs per BOE were $8.36 per BOE including FDC, down over 60% year-over-year. Our three year FD&A costs for 2P reserves, including FDC, are $14.66 per BOE.
- A total of 24.4 MMbbls of 2P crude oil reserves were added through our acquisition and capital spending activities, including technical and economic revisions, reflecting a 175% oil production replacement and offsetting the disposition of 10 MMbbls of oil reserves during the year.
- 2P natural gas reserves increased by 43% to 1.2 Tcf with the addition of 463 Bcf associated with our development, acquisition and divestment activities. The majority of the increase in 2P natural gas reserves is attributable to the Marcellus where we added 268 Bcf of 2P reserves through our capital development activities, including technical and economic factors, and 143 Bcf through acquisitions. Total Marcellus 2P reserves at year-end increased to 601 Bcf and now represent 50% of our total 2P natural gas reserves, up from 27% at year-end 2012.
- 12.1 MMBOE of 2P reserves were sold during 2013 at an average cost of $33.72 per BOE.
- 26.9 MMBOE of 2P reserves were purchased during 2013, the majority of which is attributable to the acquisition of additional working interests in the Marcellus, at an average cost of $11.25 per BOE.
- 2P reserve life index remains essentially unchanged at 10.8 years.
- An assessment of the additional resource potential within a portion of our asset base has identified 363 MMBOE of economic, best estimate contingent resources despite converting approximately 70 MMBOE of contingent resources to reserves.

Operations

- We delivered annual production growth of 9% in 2013, exceeding both our annual and exit production forecasts for the year. Daily production averaged 89,800 BOE, ahead of our guidance of 89,000 BOE per day. Total oil production increased by 5% in 2013 to average 38,250 barrels per day, despite the sale of 2,700 BOE per day of non-core oil production.
- Natural gas production increased by 15% to average 288 MMcf per day for the year, representing 54% of our annual production volumes. Strong well performance in the Marcellus combined with the acquisition of additional working interests in December helped to drive this result.
- Capital spending came in slightly lower than our forecast of $685 million, totaling $681.4 million. Approximately 70% of our spending was directed to our crude oil assets with the majority invested at Fort Berthold, North Dakota. We invested 82% of our budget on drilling and completion activities, with 62.2 net wells drilled across our asset base and 61.5 net wells brought on-stream.
- We continued to concentrate our portfolio throughout 2013. We sold $365 million of non-core assets, redeploying $245 million to increase our working interests in our crude oil waterflood portfolio and in the Marcellus. We also acquired additional acreage in the Wilrich, Marcellus and Bakken/Three Forks plays. Our net acquisition and divestment activities realized gross proceeds of $120 million in 2013.
- Our capital efficiencies improved again in 2013. Based upon our capital spending and the growth in production volumes from the fourth quarter of 2012 to the same period in 2013, we calculate a capital efficiency of approximately $26,000 per daily BOE.

Financial

- Funds flow grew by 17% year-over-year to $754 million due to the increase in production volumes, lower costs and an increase in commodity prices. On a per share basis, this was a 14% increase.
- With the increase in funds flow, a reduction in capital spending and improved capital efficiencies, our adjusted payout ratio improved to 114% in 2013 including participation in our Stock Dividend Plan ("SDP"). Monthly dividends to shareholders were maintained throughout the year, totaling $1.08 per share and represented 23% of funds flow including the SDP.
- As a result of the growth in funds flow and the net proceeds from our divestment activities, our financial flexibility increased in 2013. Approximately 80% of our bank credit facility was undrawn and our trailing twelve month debt-to-funds-flow ratio fell to 1.4 times at year end, down from 1.7 times at year end 2012.

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

The following discussion and analysis of financial results is dated February 20, 2014 and is to be read in conjunction with the audited consolidated financial statements prepared in accordance with United States Generally Accepted Accounting Principles (the "Financial Statements") of Enerplus Corporation ("Enerplus" or the "Company"), as at December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011.

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.

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.

ADOPTION OF UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

We have converted our financial reporting from International Financial Reporting Standards ("IFRS") to United States Generally Accepted Accounting Principles ("U.S. GAAP") pursuant to U.S. securities regulations as (i) over 50% of the book value of our assets (as previously calculated under IFRS) was in the United States, and (ii) over 50% of our common shares are held by U.S. residents. Reporting under U.S. GAAP began with our financial statements for the year ended December 31, 2013 with comparatives for 2012 and 2011. These U.S. GAAP financial statements are presented in Canadian dollars and satisfy both our Canadian and U.S. securities filing obligations, and IFRS based statements will no longer be prepared.

We continue to qualify as a foreign private issuer for our U.S. securities filings as less than 50% of the book value of our assets is in the United States, as calculated under U.S. GAAP, as at June 30, 2013. We are required to reassess this annually at the end of our second quarter and should our U.S. asset book value exceed 50% of our corporate total as calculated under U.S. GAAP, we would fail to qualify as a foreign private issuer and would become subject to U.S. domestic filing requirements effective the first day of the following calendar year.

The most significant differences between U.S. GAAP and IFRS that impact Enerplus relate to the accounting for our oil and gas assets, particularly accounting for impairment, depletion, divestments, and asset retirement obligations.

Under U.S. GAAP oil and gas sales are generally presented net of royalties and U.S. industry protocol is to present production volumes net of royalties. Under IFRS and Canadian industry protocol oil and gas sales and production volumes are presented before deduction of any royalties. In order to continue to be comparable with our Canadian peer companies, this MD&A presents our production and BOE measures on a Company interest basis before deduction of any royalties.

The following provides a reconciliation of our production volumes:

Average Daily Production Volumes	2013	2012	2011
	Year ended December 31		
Company interest production volumes			
Crude oil (bbls/day)	38,250	36,509	30,181
Natural gas liquids (bbls/day)	3,472	3,627	3,306
Natural gas (Mcf/day)	288,423	251,773	251,068
Company interest production volumes (BOE/day)	89,793	82,098	75,332
Royalty volumes			
Crude oil (bbls/day)	6,938	6,315	4,923
Natural gas liquids (bbls/day)	802	837	770
Natural gas (Mcf/day)	42,192	30,294	31,015
Royalty volumes (BOE/day)	14,772	12,201	10,862
Net production volumes			
Crude oil (bbls/day)	31,312	30,194	25,258
Natural gas liquids (bbls/day)	2,670	2,790	2,536
Natural gas (Mcf/day)	246,231	221,479	220,053
Net production volumes (BOE/day)	75,021	69,897	64,470

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 to evaluate operating performance of our crude oil and natural gas assets. The term netback is calculated as oil and natural gas sales revenue (net of transportation), less royalties, production taxes and operating costs.

"Funds Flow" is used to analyze operating performance, leverage and liquidity. Funds flow is calculated as net cash provided by operating activities but before changes in non-cash operating working capital and asset retirement obligation expenditures.

Reconciliation of Cash Flow from Operating Activities to Funds flow	2013	2012	2011
	Year ended December 31		
Cash flow from operating activities	$ 766.5	$ 535.7	$ 624.2
Asset retirement obligation expenditures	16.6	19.9	21.7
Changes in non-cash operating working capital	(28.9)	88.9	(71.5)
Funds flow	$ 754.2	$ 644.5	$ 574.4

"Debt to Funds Flow Ratio" is used to analyze 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 to analyze operating performance, leverage and liquidity. We calculate our adjusted payout ratio as dividends to shareholders, net of our Stock Dividend Program ("SDP") and former Dividend Reinvestment Program ("DRIP") proceeds, plus capital spending (including office capital) divided by funds flow.

2013 FOURTH QUARTER OVERVIEW

Production continued to exceed our expectations averaging 94,167 BOE/day during the fourth quarter, concluding a year of significant production growth. Strong fourth quarter production was driven by continued outperformance and the acquisition of additional working interests in the Marcellus. Despite an improvement in natural gas prices, funds flow during the fourth quarter totaled $180.7 million compared to $196.2 million in the third quarter, primarily due to wider crude oil differentials along with higher share-based compensation. We continued to focus our portfolio during the quarter, recognizing proceeds of $168.7 million through our divestment activity. We maintained a strong balance sheet exiting the year with a conservative trailing 12-month debt to funds flow ratio of 1.4x.

SUMMARY FOURTH QUARTER INFORMATION

In comparing the fourth quarter of 2013 with the same period in 2012:

- Average daily production was 94,167 BOE/day compared to 85,490 BOE/day in 2012, with the majority of the growth coming from our Marcellus and Fort Berthold properties in the U.S. and our Wilrich properties in Canada. Our average daily production for December was 99,569 BOE/day, ahead of our exit guidance of 95,000 BOE/day.
- Funds flow totaled $180.7 million compared to $200.4 million in 2012. Funds flow decreased from the fourth quarter of 2012 primarily due to higher operating costs and share-based compensation, offset by higher oil and gas sales.
- Cash general and administrative ("G&A") expenses were $2.28/BOE compared to $2.34/BOE in 2012. The decrease in cash G&A expense on a per BOE basis was due to higher production during the period.
- Cash share-based compensation expense increased to $1.06/BOE compared to $0.03/BOE in 2012 due to the increase in our share price during the quarter.
- Capital spending increased to $223.0 million compared to $160.9 million in 2012. Our fourth quarter capital spending was in line with expectations with the majority of our spending focused on our core operating areas. During the quarter, we invested $95.9 million in Fort Berthold, $24.3 million in the Marcellus, $48.5 million on our Canadian crude oil waterflood properties, and $43.2 million on our Canadian Deep Gas properties.
- Property and land acquisitions were $173.4 million compared to $121.4 million in 2012. During the fourth quarter of 2013 we purchased additional working interests in our core Marcellus properties for $157.9 million, representing approximately 42 MMcf/day of production.
- Divestments totaled $168.0 million compared to $220.1 million in 2012. In the fourth quarter we disposed of non-core Canadian oil properties for proceeds of $103.6 million and entered into agreements to sell our undeveloped Montney acreage for $134.6 million, after adjustments, of which $65.7 million was closed during the quarter with the remainder recognized in January 2014. During the fourth quarter of 2012 we divested of our non-core properties in Manitoba for proceeds of $218.1 million.

SELECTED FOURTH QUARTER CANADIAN AND U.S. FINANCIAL RESULTS

(CDN$ millions, except per unit amounts)	Three months ended December 31, 2013 Canada	U.S.	Total	Three months ended December 31, 2012 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	16,703	21,028	37,731	20,713	17,884	38,597
Natural gas liquids (bbls/day)	2,858	955	3,813	3,177	399	3,576
Natural gas (Mcf/day)	165,114	150,625	315,739	188,628	71,276	259,904
Total average daily production (BOE/day)	47,080	47,087	94,167	55,328	30,162	85,490
Pricing[2]						
Crude oil (per bbl)	$ 70.05	$ 83.89	$ 77.77	$ 72.01	$ 82.25	$ 76.75
Natural gas liquids (per bbl)	52.39	59.87	54.26	48.09	41.08	47.31
Natural gas (per Mcf)	3.12	3.41	3.26	2.76	3.67	3.01
Capital Expenditures						
Capital spending	$ 102.1	$ 120.9	$ 223.0	$ 50.3	$ 110.6	$ 160.9
Acquisitions	0.4	173.0	173.4	(0.2)	121.6	121.4
Dispositions	(168.7)	0.7	(168.0)	(220.2)	–	(220.2)
Revenues						
Oil and natural gas sales[2]	$ 168.8	$ 210.6	$ 379.4	$ 199.8	$ 160.9	$ 360.7
Commodity derivative instruments gain/(loss)	10.2	–	10.2	17.7	–	17.7
Expenses						
Operating	$ 66.8	$ 24.4	$ 91.2	$ 57.9	$ 13.9	$ 71.8
Royalties	23.7	40.9	64.6	26.7	30.5	57.2
Production taxes	2.3	15.6	17.9	2.4	15.4	17.8
General and administrative	14.5	5.2	19.7	20.0	3.9	23.9
Depletion, depreciation, amortization and accretion	59.3	63.8	123.1	87.1	55.4	142.5
Current income tax expense/(recovery)	(0.4)	0.3	(0.1)	(2.2)	1.5	(0.7)

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

2013 OVERVIEW

Summary of Guidance and Results	Original 2013 Guidance	Revised 2013 Guidance	2013 Results	2014 Guidance
Average annual production (BOE/day)	82,000 – 85,000	89,000	89,793	96,000 – 100,000
Capital spending (CDN$ millions)	$ 685	$ 685	$ 681	$ 760
Production mix volumes (% crude oil and liquids)	50%	48%	46%	48%
Average royalty and production tax rate (% of gross sales, net of transportation)	21%	21%	21%	23.5%
Operating costs (per/BOE)	$ 10.70	$ 10.70	$ 10.48	$ 10.25
G&A Expenses – cash (per/BOE)	$ 2.70	$ 2.70	$ 2.54	$ 2.45
Share based compensation expenses – cash (per/BOE)	$ 0.45	$ 0.60	$ 0.71	$ 0.25

Production increased by over 9% during 2013, averaging 89,793 BOE/day and exceeding our annual average guidance of 89,000 BOE/day. We exited the year with average production of 99,569 BOE/day in December, exceeding our exit guidance of 95,000 BOE/day. We had an average crude oil and liquids weighting of 46% for 2013 compared to 49% in 2012 despite growth in our crude oil production of 5% year-over-year. Our crude oil divestment activity and production outperformance in the Marcellus contributed to the change in our production weighting.

Capital spending and operating costs were lower than expected at $681.4 million and $10.48/BOE respectively. G&A expenses were consistent with our expectations at $2.54/BOE, however cash share-based compensation expense was higher than expected at $0.71/BOE given the increase in our share price during the period. Funds flow increased 17% over 2012 at $754.2 million. Stronger crude oil and natural gas prices and higher production contributed to this increase.

We continued to make progress in focusing our portfolio and concentrating on our core operating areas. We sold $365.1 million of non-core assets representing production of approximately 2,700 BOE/day and reinvested $244.8 million into our core areas through transactions that included the acquisition of crude oil waterflood properties in Canada and additional working interests in the Marcellus. On a net basis, we realized proceeds of $120.3 million from our acquisition and divestment activities during the period.

With the increase in funds flow and a reduction in capital spending, our adjusted payout ratio fell to 114% in 2013. Monthly dividends to shareholders were maintained throughout the year totaling $1.08 per share. Our financial flexibility also improved in 2013, as we ended the year with a debt to funds flow ratio of 1.4x and approximately $786 million of available credit on our bank facility.

RESULTS OF OPERATIONS

Production

Average Daily Production Volumes	2013	2012	2011
Crude oil (bbls/day)	38,250	36,509	30,181
Natural gas liquids (bbls/day)	3,472	3,627	3,306
Natural gas (Mcf/day)	288,423	251,773	251,068
Total daily sales (BOE/day)	89,793	82,098	75,332

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% as production from our Fort Berthold properties grew by approximately 4,700 BOE/day in 2013. 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 in the assets.

2012 versus 2011

Production for 2012 averaged 82,098 BOE/day, representing an increase of 9% from 2011. Our crude oil production increased by 21% mainly due to our successful capital development program at our Fort Berthold properties. Natural gas volumes were relatively flat year-over-year as increased volumes from our Marcellus assets offset production declines on our Canadian conventional natural gas properties.

2014 Guidance

We expect to deliver 9% production growth again in 2014, targeting annual average production between 96,000 BOE/day and 100,000 BOE/day. This guidance does not contemplate future acquisitions or 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.

Average Selling Price[1]	2013	2012	2011
Crude oil (per bbl)	$ 83.99	$ 78.19	$ 83.48
Natural gas liquids (per bbl)	52.25	53.01	64.99
Natural gas (per Mcf)	3.26	2.39	3.72
Per BOE	48.11	44.56	48.85

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

Average Benchmark Pricing	2013	2012	2011
WTI crude oil (US$/bbl)	$ 97.97	$ 94.21	$ 95.12
AECO natural gas – monthly index (CDN$/Mcf)	3.16	2.40	3.68
AECO natural gas – daily index (CDN$/Mcf)	3.17	2.39	3.62
NYMEX natural gas – monthly NX3 index (US$/Mcf)	3.67	2.80	4.07
US/CDN exchange rate	1.03	1.00	0.99

Average Differentials (US$/bbl or US$/Mcf)		**2013**		**2012**		**2011**
MSW Edmonton – WTI	$	(7.57)	$	(7.79)	$	1.33
WCS Hardisty – WTI		(25.20)		(21.03)		(17.15)
Brent Futures (ICE) – WTI		10.77		17.45		15.72
AECO monthly – NYMEX		(0.58)		(0.39)		(0.32)

CRUDE OIL AND NATURAL GAS LIQUIDS

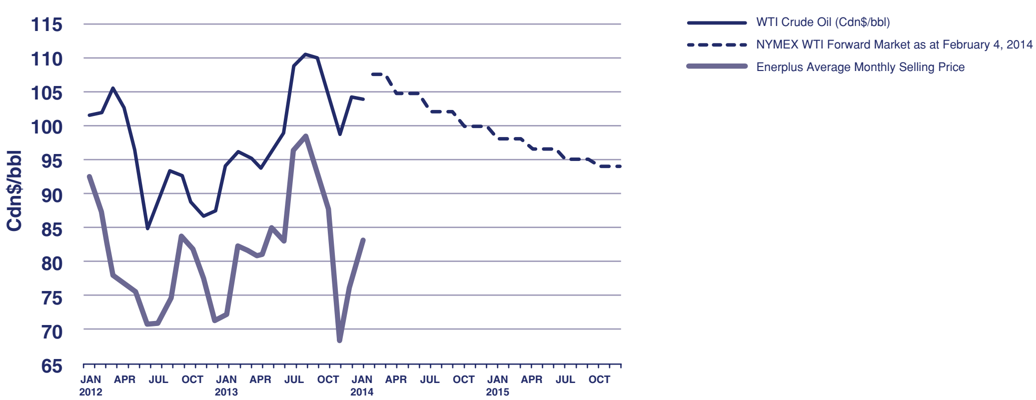
WTI started 2013 trading at US$93.12/bbl and ended the year trading at US$98.42, averaging US$97.97/bbl over the period. A low of US$86.68/bbl was reached in April as U.S. crude oil inventories reached their highest point in 25 years. Geopolitical tensions in Syria, Iran and Libya, combined with a strong turnaround in U.S. refining demand and associated decline in U.S. crude oil stocks, helped push WTI prices to a peak of US$110.53/bbl in early September. Some of the geopolitical tension eased during the latter part of the year, resulting in WTI prices falling by over US$17.00/bbl by the end of the year. Brent/WTI differentials averaged US$10.77/bbl, which was US$6.68/bbl narrower versus 2012, as increased domestic light sweet crude oil production began to displace imported crudes.

Heavy crude oil differentials in Canada continued to widen in 2013, averaging US$4.17/bbl wider than 2012, due to increased Canadian heavy crude oil production and a number of unplanned outages and refinery turnarounds throughout the year. Light oil differentials in Canada were virtually unchanged on average compared to 2012, although they widened significantly in the fourth quarter due to constraints on export pipelines and the continued growth in light oil production in the U.S.

Enerplus' crude oil stream differential discount to WTI in 2013 averaged US$13.98/bbl versus US$16.02/bbl in 2012. The average price received for our crude oil (net of transportation costs) was $83.99/bbl for 2013, a 7% increase over 2012. In comparison, the WTI benchmark increased by 4% over the same period. The difference between the change in WTI and the change in our realized prices is largely due to a weaker Canadian dollar in 2013 which helped to increase our realized prices.

In 2014 we expect our U.S. Bakken and Three Forks oil will trade at US$12.00/bbl discount to WTI. In Canada, we expect the Mixed Sweet Blend ("MSW") to trade at an US$8.00/bbl discount and Western Canadian Select ("WCS") to trade at a US$25.00/bbl discount to WTI during 2014.

MONTHLY CRUDE OIL PRICES



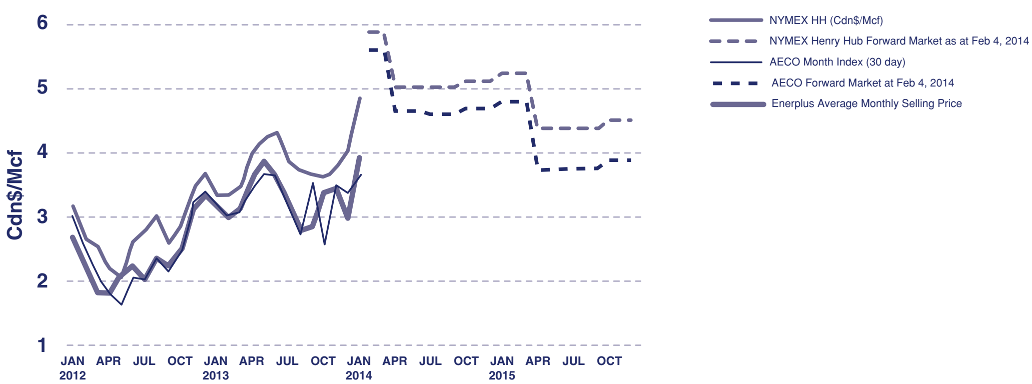
NATURAL GAS

Natural gas prices at both AECO and NYMEX strengthened considerably versus 2012. AECO monthly index prices increased by 32% to average $3.16/Mcf for the year, while NYMEX gas prices increased by 31% to average US$3.67/Mcf. Colder than normal weather late last winter pushed AECO monthly prices to $3.68/Mcf in the spring, with NYMEX reaching US$4.19/Mcf in June. These gains were short-lived as significant production growth in the U.S. and cooler than expected weather put significant pressure on natural gas prices during the summer months. However, record withdrawals from storage were seen in December in the U.S., helping push spot NYMEX prices to approximately US$4.50/Mcf before year-end.

Natural gas prices in the Marcellus weakened throughout the year given increased production in the region and takeaway capacity constraints. Monthly spot prices on the Transco Leidy and Tennessee Gas Pipeline 300 Leg weakened from approximately $0.30/MMBtu below NYMEX in early summer to as high as $2.00/MMBtu below NYMEX by the fourth quarter due to increased capacity constraints. In 2013 approximately 50% of our natural gas was sold under long-term sales contracts at market points with stronger pricing. This provided some protection from these discounts, resulting in our realized discount to NYMEX averaging US$0.33/MMBtu for the year. We expect wider differentials to continue in the region until pipeline expansions are built, and within the context of stronger natural gas prices we are forecasting our differential to NYMEX to average $1.00/MMBtu in 2014.

Overall, we sold our natural gas for an average price of $3.26/Mcf (net of transportation costs) in 2013 which represented a 36% increase from 2012. The increase in our realized price was in line with the year-over-year changes in both AECO and NYMEX prices.

MONTHLY NATURAL GAS PRICES



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. We have hedged a significant portion of our crude oil production in 2014 as it currently accounts for approximately 80% of our corporate netback. As of February 4, 2014 we have swapped an average of 19,500 bbls/day for 2014 at an average price of US$94.02/bbl, which represents approximately 59% of our forecasted net oil production after royalties. We have not added material crude oil positions for 2015 given the significant backwardation in the forward curve.

We have entered into WCS differential swap positions for 2014 to manage exposure against heavy crude oil differentials. These differential swaps have been fixed at WTI less US$21.88/bbl on 2,000 bbls/day for February through December of 2014.

As of February 4, 2014 we have downside protection on approximately 40% of our forecasted natural gas production after royalties for 2014. This is comprised of 75,000 Mcf/day at a NYMEX price of US$4.14/Mcf. In addition, we purchased a call spread whereby we participate in price upside between US$4.17/Mcf and US$5.00/Mcf on 25,000 Mcf/day at NYMEX. At AECO we have approximately 19,000 Mcf/day hedged at an average price of CDN$4.21/Mcf, weighted towards the second half of 2014. For 2015, we have swapped 20,000 Mcf/day at a NYMEX price of US$4.16/Mcf.

The following is a summary of our financial contracts in place at February 4, 2014, expressed as a percentage of our anticipated net production volumes:

	Crude Oil (US$/bbl)[1]			AECO Natural Gas (CDN$/Mcf)			NYMEX Natural Gas (US$/Mcf)	
	Jan 1, 2014 – Jun 30, 2014	Jul 1, 2014 – Dec 31, 2014	Jan 1, 2015 – Dec 31, 2015	Jan 1, 2014 – Mar 31, 2014	Apr 1, 2014 – Jun 30, 2014	Jul 1, 2014 – Dec 31, 2014	Jan 1, 2014 – Dec 31, 2014	Jan 1, 2015 – Dec 31, 2015
Sold Puts							$ 3.23	
%							11%	
Swaps	$ 93.98	$ 94.07	$ 90.00	$ 3.96	$ 4.12	$ 4.25	$ 4.14	$ 4.16
%	70%	48%	2%	2%	6%	12%	32%	9%
Sold Calls							$ 5.00	
%							11%	
Purchased Calls							$ 4.17	
%							11%	

(1) Based on weighted average price (before premiums), assumed average annual production of 98,000 BOE/day for 2014 and 2015, less royalties and production taxes of 23.5% in aggregate.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Risk Management Gains/(Losses) ($ millions)	2013	2012	2011
Cash gains/(losses):			
Crude oil	$ 24.4	$ 18.4	$ (46.5)
Natural gas	2.2	–	13.3
Total cash gains/(losses)	$ 26.6	$ 18.4	$ (33.2)
Non-cash gains/(losses) on financial contracts:			
Change in fair value – crude oil	$ (65.5)	$ 70.3	$ 18.7
Change in fair value – natural gas	(3.0)	3.3	(12.6)
Total non-cash gains/(losses)	$ (68.5)	$ 73.6	$ 6.1
Total gains/(losses)	$ (41.9)	$ 92.0	$ (27.1)

(Per BOE)	2013	2012	2011
Total cash gains/(losses)	$ 0.81	$ 0.61	$ (1.21)
Total non-cash gains/(losses)	(2.09)	2.45	0.22
Total gains/(losses)	$ (1.28)	$ 3.06	$ (0.99)

2013 versus 2012

During 2013 we realized cash gains of $24.4 million on our crude oil contracts and $2.2 million on our natural gas contracts. In comparison, during 2012 we realized cash gains of $18.4 million on our crude oil contracts. The cash gains in 2013 and 2012 were due to contracts which provided floor protection above market prices.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At December 31, 2013 the fair value of our crude oil contracts represented a loss position of $14.8 million, while our natural gas contracts represented a gain position of $0.3 million. For the year ended December 31, 2013 the fair value of our crude oil contracts decreased $65.5 million while the fair value of our natural gas contracts decreased $3.0 million. See Note 15 for details.

2012 versus 2011

During 2012 we realized cash gains of $18.4 million on our crude oil contracts. In comparison, in 2011 we realized cash losses of $46.5 million on our crude oil contracts and gains of $13.3 million on our natural gas contracts. The cash gains in 2012 were due to contracts which provided floor protection above market prices. The cash losses in 2011 were a result of crude oil prices rising above our fixed price swap positions.

At December 31, 2012 the fair value of our crude oil and natural gas contracts represented gains of $50.7 million and $3.3 million respectively. For the year ended December 31, 2012 the fair value of our crude oil and natural gas contracts increased $70.3 million and $3.3 million, respectively.

Revenues

($ millions)	2013	2012	2011
Oil and natural gas sales	$ 1,616.8	$ 1,365.5	$ 1,363.7
Royalties	(264.3)	(212.2)	(205.1)
Oil and natural gas sales, net of royalties	$ 1,352.5	$ 1,153.3	$ 1,158.6

2013 versus 2012

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

2012 versus 2011

Oil and gas sales revenues of $1,365.5 million in 2012 were similar to 2011 revenues of $1,363.7 million. Increased production volumes in 2012 were offset by lower realized prices.

Royalties and Production Taxes

($ millions, except per BOE amounts)	2013	2012	2011
Royalties	$ 264.3	$ 212.2	$ 205.1
Per BOE	$ 8.06	$ 7.06	$ 7.46
Production taxes	$ 70.4	$ 56.6	$ 40.1
Per BOE	$ 2.15	$ 1.89	$ 1.46
Royalties and production taxes	$ 334.7	$ 268.8	$ 245.2
Per BOE	$ 10.21	$ 8.95	$ 8.92
Royalties and production taxes (% of oil and natural gas sales, net of transportation)	21%	20%	18%

(1) Prior to adoption of U.S. GAAP, Enerplus reported the aggregate of royalties and production taxes as a single "Royalties" category on the Consolidated Income Statement.

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.

2013 versus 2012

Royalties and production taxes increased to $334.7 million in 2013 from $268.8 million in 2012 due to increased production, particularly in the U.S. where rates are higher. Royalties and production taxes averaged 21% of oil and gas sales (net of transportation) in 2013 compared to 20% in 2012.

2012 versus 2011

Royalties and production taxes were $268.8 million in 2012 compared to $245.2 in 2011. Royalties and production taxes increased to 20% of oil and gas sales (net of transportation) from 18% in 2011, due to increased U.S. production levels.

Guidance

We are expecting average royalty and production taxes in 2014 to increase to 23.5% of expected oil and gas sales (net of transportation).

Transportation Costs

($ millions, except per BOE amounts)	2013	2012	2011
Transportation costs	$ 39.9	$ 26.6	$ 20.6
Per BOE	$ 1.22	$ 0.88	$ 0.75

Transportation costs for 2013 were $39.9 million compared to $26.6 million in 2012 and $20.6 million in 2011. The increased transportation costs are related to our increasing U.S. production as well as costs associated with securing U.S. pipeline capacity.

Operating Expenses

($ millions, except per BOE amounts)	2013	2012	2011
Operating Expenses	$ 343.4	$ 319.0	$ 280.4
Per BOE	$ 10.48	$ 10.62	$ 10.20

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.

2012 versus 2011

Our 2012 operating expenses totaled $319.0 million ($10.62/BOE) compared to $280.4 million ($10.20/BOE) in 2011. In 2012 we had additional facility charges at Fort Berthold and higher well servicing and repairs and maintenance costs as poor weather in 2011 delayed some maintenance into 2012.

2014 Guidance

We are expecting our 2014 operating expenses to decrease to approximately $10.25/BOE.

Netbacks

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

	Year ended December 31, 2013		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	42,587 BOE/day	283,237 Mcfe/day	89,793 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 76.90	$ 3.70	$ 48.11
Royalties and production taxes	(18.39)	(0.48)	(10.21)
Cash operating costs	(12.23)	(1.49)	(10.50)
Netback before hedging	$ 46.28	$ 1.73	$ 27.40
Cash gains/(losses)	1.57	0.02	0.81
Netback after hedging	$ 47.85	$ 1.75	$ 28.21
Netback before hedging ($ millions)	$ 719.3	$ 178.7	$ 898.0
Netback after hedging ($ millions)	$ 743.7	$ 180.9	$ 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

Netbacks by Property Type	Year ended December 31, 2011 Crude Oil	Natural Gas	Total
Average Daily Production	33,185 BOE/day	252,883 Mcfe/day	75,332 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 77.17	$ 4.42	$ 48.85
Royalties and production taxes	(16.27)	(0.52)	(8.92)
Cash operating costs	(11.77)	(1.52)	(10.30)
Netback before hedging	$ 49.13	$ 2.38	$ 29.63
Cash gains/(losses)	(3.84)	0.14	(1.21)
Netback after hedging	$ 45.29	$ 2.52	$ 28.42
Netback before hedging ($ millions)	$ 595.3	$ 219.4	$ 814.7
Netback after hedging ($ millions)	$ 548.8	$ 232.7	$ 781.5

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

Our crude oil properties accounted for 80% of our corporate netback before hedging in 2013 compared to 86% and 73% in 2012 and 2011, respectively.

During 2013 crude oil netbacks per BOE and natural gas netbacks per Mcfe increased compared to 2012 primarily due to improved realized prices. Our 2012 crude oil netbacks per BOE after hedging were similar to 2011 as lower realized prices were offset by cash hedging gains, while natural gas netbacks per Mcfe decreased due to lower realized prices.

General and Administrative (G&A) Expenses

Total G&A expenses include cash G&A expenses as well as share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans") and our stock option plan (see Note 14 for further details). SBC charges are dependent on our share price and can fluctuate from period to period.

($ millions)	2013	2012	2011
Cash:			
G&A expense(1)	$ 83.2	$ 78.3	$ 67.6
SBC	23.3	5.6	14.5
Non-Cash:			
SBC – equity swap loss/(gain)	(5.4)	(0.4)	–
SBC – Stock option plan	9.2	10.3	12.3
Total G&A expenses	$ 110.3	$ 93.8	$ 94.4

(Per BOE)	2013	2012	2011
Cash:			
G&A expense(1)	$ 2.54	$ 2.61	$ 2.46
SBC	0.71	0.18	0.53
Non-Cash:			
SBC – equity swap loss/(gain)	(0.17)	(0.01)	–
SBC – Stock option plan	0.28	0.34	0.45
Total G&A expenses	$ 3.36	$ 3.12	$ 3.44

(1) Excluding share-based compensation.

2013 versus 2012

Cash G&A expenses were $83.2 million 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 SBC was $23.3 million in 2013 compared to $5.6 million in 2012. Higher cash SBC 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 because of our total return relative to the TSX oil and gas index.

We recorded non-cash gains of $5.4 million in 2013 compared to gains of $0.4 million in 2012 on our equity swaps. These gains result from the change in fair value of the equity swaps which effectively fix the future settlement cost on a portion of the outstanding units under the plans. At December 31, 2013 we had fixed the settlement cost on 1,130,000 shares at a weighted average price of $13.86 per share.

2012 versus 2011

Cash G&A expenses were $78.3 million in 2012 compared to $67.6 million in 2011. The increase in 2012 was primarily due to expanding our U.S. operations as well as higher professional and legal fees.

Cash SBC expenses decreased to $5.6 million in 2012 from $14.5 million in 2011. Our LTI costs were significantly lower in 2012 as a result of the decrease in our share price during the year.

2014 Guidance

For 2014 we expect cash G&A expenses of approximately $2.45/BOE. We also anticipate cash SBC to decrease to approximately $0.25/BOE as we expect future grants under our LTI plans will be treasury settled as compared to our current practice of cash settlement.

Interest Expense

($ millions)	2013	2012	2011
Interest on senior notes and bank facility	$ 56.7	$ 53.1	$ 47.0
Non-cash interest expense	1.6	1.8	(2.1)
Total interest expense	$ 58.3	$ 54.9	$ 44.9

Interest on our senior notes and bank credit facility in 2013 totaled $58.3 million compared to $54.9 million in 2012 and $44.9 million in 2011. The increases in 2013 and 2012 are due to an increased weighting of senior notes with higher interest rates after our $405 million private placement of senior notes in May 2012. Non-cash amounts recorded in finance 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"). See Note 11 for further details.

At December 31, 2013, after including our underlying derivatives, approximately 74% of our debt was based on fixed interest rates and 26% on floating interest rates.

Foreign Exchange

($ millions)	2013	2012	2011
Realized loss/(gain)	$ 17.6	$ 6.5	$ 18.4
Unrealized loss/(gain)	(8.3)	(23.7)	(14.2)
Total foreign exchange loss/(gain)	$ 9.3	$ (17.2)	$ 4.2

We recorded a net foreign exchange loss of $9.3 million in 2013 compared to a gain of $17.2 million in 2012 and loss of $4.2 million in 2011. In each of these years 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 (2013 – $17.8 million, 2012 – $18.4 million, 2011 – $19.1 million) and recognized a corresponding unrealized gain to remove the mark-to-market position previously recorded on the balance sheet. We also had unrealized foreign exchange gains in 2013 on the translation of our U.S. debt and working capital. See Note 12 for details.

Capital Investment

($ millions)	2013	2012	2011
Capital spending	$ 681.4	$ 853.4	$ 866.5
Office capital	6.5	11.9	11.3
Sub-total	$ 687.9	$ 865.3	$ 877.8
Property and land acquisitions	$ 244.8	$ 185.3	$ 255.2
Property divestments	(365.1)	(275.8)	(641.2)
Sub-total	$ (120.3)	$ (90.5)	$ (386.0)
Total net capital investment	$ 567.6	$ 774.8	$ 491.8

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 liquids rich deep gas properties in Canada and $78.7 million developing our Marcellus assets. Through our capital program in 2013 we added 78 MMBOE of proved plus probable reserves, replacing approximately 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 $134.6 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 80% directed towards oil and liquids rich natural gas 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 liquids rich 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 57.3 MMBOE of 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 were $275.8 million which 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.

2011

Capital spending during 2011 totaled $866.5 million and was focused on our key growth areas. We spent $375.0 million on our Bakken oil assets in the U.S. and Canada, $164.0 million on our crude oil waterflood properties, $210.0 million on our Marcellus assets and $84.0 million on our deep gas plays.

Property and land acquisitions in 2011 totaled $255.2 million which included $112.5 million on undeveloped land in Canada and US$111.0 million on our Marcellus carry obligation.

Property divestments in 2011 were $641.2 million including the sale of approximately 91,000 net acres of our Marcellus interests for proceeds of $567.9 million and the divestment of non-core Canadian assets for proceeds of approximately $61.8 million.

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

($ millions, except per BOE amounts)	2013	2012	2011
DDA&A expense	$ 593.2	$ 560.3	$ 509.6
Per BOE	$ 18.10	$ 18.65	$ 18.53

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For 2013 DDA&A was $593.2 million compared to $560.3 million in 2012 and $509.6 million in 2011. The increases were primarily due to higher production and capital costs with respect to our U.S. operations.

Impairments

($ millions, except per BOE amounts)	2013	2012	2011
Impairment expense	$ –	$ 781.1	$ 209.4
Per BOE	$ –	$ 26.00	$ 7.62

Under U.S. GAAP, the ceiling test is performed using estimated after-tax future net cash flows from proved reserves as calculated under 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 gas properties in 2013. During 2012 and 2011, non-cash impairments totaling $781.1 million and $209.4 million, respectively, were recorded in the United States cost center. These impairments were due to our 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. No impairments were recorded in the Canadian cost center in the comparative periods.

Marketable Securities

During 2013 we sold marketable securities for proceeds of $2.5 million recognizing a gain of $0.4 million. During 2012 we sold securities, the most significant being our shares in Laricina Energy Ltd., for net cash proceeds of $146.9 million resulting in a gain of $86.5 million.

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 estimated by management based on our net ownership interest, estimated costs to abandon and reclaim and the estimated timing of the costs to be incurred in future periods.

We have estimated the net present value of our asset retirement obligation to be $291.8 million at December 31, 2013 compared to $256.1 million at December 31, 2012. Our overall liability increased year-over-year primarily due to higher cost estimates along with a decrease in the weighted credit-adjusted risk free rate used to calculate the present value of the liability, which decreased to 5.96% at December 31, 2013 from 6.15% at December 31, 2012. See Note 9 for further information.

We take an active approach to managing our abandonment, reclamation and remediation obligations. During 2013 we spent $16.6 million (2012 – $19.9 million; 2011 – $21.7 million) on our asset retirement obligations and we expect to spend approximately $26.6 million in 2014. Our abandonment and reclamation costs are expected to be incurred over the next 66 years with the majority between 2024 and 2053. 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)	2013	2012	2011
Current tax expense/(recovery)	$ 7.9	$ 1.6	$ 81.2
Deferred tax expense/(recovery)	30.7	(274.6)	(163.6)
Total tax expense/(recovery)	$ 38.6	$ (273.0)	$ (82.4)

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.

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 center.

2012 versus 2011

The increased tax recovery of $273.0 million in 2012 compared to $82.4 million in 2011 relates primarily to the decrease in net income in 2012 due to non-cash ceiling test impairments in our U.S. cost center. Our current taxes were higher in 2011 due to our Marcellus property disposition and resulting gain for income tax purposes.

2014 Guidance

We expect to pay U.S. cash taxes (AMT) of approximately 3-5% of U.S. funds flow in 2014 and 2015. We currently do not expect to pay material cash taxes in Canada until after 2018. 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, 2013 and 2012 are as follows:

Pool Type ($ millions)	**2013**	**2012**
Canada		
Canadian oil and gas property expenditures ("COGPE")	$ 111	$ 315
Canadian development expenditures ("CDE")	365	316
Canadian exploration expenditures ("CEE")	224	216
Undepreciated capital costs ("UCC")	295	375
Non-capital losses and other credits	459	488
	1,454	1,710
U.S.		
Alternative minimum tax credit ("AMT")	99	84
Net operating losses	463	462
Depletable and depreciable assets	1,253	1,048
	1,815	1,594
Total tax pools and credits	$ 3,269	$ 3,304
Capital losses – Canada	$ 1,208	$ 1,212

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, 2013			**Year ended December 31, 2012**		
(CDN$ millions, except per unit amounts)	**Canada**	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	17,862	20,388	38,250	20,647	15,862	36,509
Natural gas liquids (bbls/day)	2,801	671	3,472	3,244	383	3,627
Natural gas (Mcf/day)	175,876	112,547	288,423	198,356	53,417	251,773
Total average daily production (BOE/day)	49,976	39,817	89,793	56,950	25,148	82,098
Pricing(2)						
Crude oil (per bbl)	$ 77.67	$ 89.52	$ 83.99	$ 75.21	$ 82.08	$ 78.19
Natural gas liquids (per bbl)	55.51	38.64	52.25	54.86	37.35	53.01
Natural gas (per Mcf)	3.01	3.66	3.26	2.17	3.21	2.39
Capital Expenditures						
Capital spending	$ 286.5	$ 394.9	$ 681.4	$ 255.4	$ 598.0	$ 853.4
Acquisitions	44.4	200.4	244.8	13.6	171.7	185.3
Divestments	(323.2)	(41.9)	(365.1)	(253.9)	(21.9)	(275.8)
Revenues						
Oil and natural gas sales(2)	$ 758.2	$ 818.7	$ 1,576.9	$ 794.1	$ 544.9	$ 1,339.0
Commodity derivative instruments gain/(loss)	(41.9)	–	(41.9)	92.0	–	92.0
Expenses						
Operating	$ 259.1	$ 84.3	$ 343.4	$ 266.3	$ 52.7	$ 319.0
Royalties	105.8	158.5	264.3	109.9	102.3	212.2
Production taxes	10.1	60.3	70.4	11.6	45.0	56.6
General and administrative	92.4	17.9	110.3	78.9	14.9	93.8
DDA&A	300.5	292.7	593.2	322.1	238.2	560.3
Impairments	–	–	–	–	781.1	781.1
Current income tax expense/(recovery)	(0.6)	8.5	7.9	(2.1)	3.7	1.6

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

THREE YEAR SUMMARY OF KEY MEASURES

($ millions, except per share amounts)	2013	2012	2011
Oil and natural gas sales[(1)]	$ 1,576.9	$ 1,339.0	$ 1,343.1
Net income/(loss)	48.0	(270.7)	12.8
Per share (Basic)	0.24	(1.38)	0.07
Per share (Diluted)	0.24	(1.38)	0.07
Funds flow	754.2	644.5	574.4
Per share (Basic)	3.76	3.29	3.19
Cash and stock dividends[(2)]	216.9	301.6	388.9
Per share (Basic)[(2)]	1.08	1.54	2.16
Total assets	3,681.8	3,618.4	3,856.1
Long-term debt, net of cash[(3)]	1,022.3	1,064.4	901.5

(1) Net of transportation costs, but before royalties and the effects of commodity derivative instruments.
(2) 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.
(3) Including current portion of long-term debt.

2013 versus 2012

Oil and gas sales increased in 2013 due to higher realized crude oil and natural gas prices and increased production volumes.

Net income and funds flow improved over 2012 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 in July 2012.

2012 versus 2011

Oil and gas sales were relatively flat for 2012 compared to 2011 as higher production volumes offset the impact of lower realized commodity prices. In 2012 we recorded a net loss of $270.7 million, primarily due to non-cash asset impairment charges.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales[(1)]	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2013				
Fourth Quarter	$ 379.4	$ 29.6	$ 0.15	$ 0.15
Third Quarter	432.7	(3.7)	(0.02)	(0.02)
Second Quarter	398.6	38.5	0.19	0.19
First Quarter	366.2	(16.4)	(0.08)	(0.08)
Total 2013	$ 1,576.9	$ 48.0	$ 0.24	$ 0.24
2012				
Fourth Quarter	$ 360.7	$ 34.6	$ 0.18	$ 0.18
Third Quarter	324.9	(88.6)	(0.45)	(0.45)
Second Quarter	314.4	(41.9)	(0.21)	(0.21)
First Quarter	339.0	(174.8)	(0.92)	(0.92)
Total 2012	$ 1,339.0	$ (270.7)	$ (1.38)	$ (1.38)

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

Oil and gas sales increased through the third quarter of 2013 mainly due to strengthening crude oil prices and increased natural gas production in the Marcellus. While we continued to see strong production growth from our Marcellus assets in the fourth quarter, realized crude oil pricing weakened contributing to a decrease in oil and gas sales. During 2012 oil and gas sales were relatively flat compared to 2011 as increased production volumes were offset by lower realized commodity prices.

Net income for 2013 and 2012 was impacted by fluctuating risk management costs, asset impairment charges, gains on marketable security divestments and resulting tax provisions.

LIQUIDITY AND CAPITAL RESOURCES

In 2013 we continued to maintain our liquidity and financial flexibility through an increased focus on cost efficiencies, a disciplined capital program, and the sale of non-core properties. We closed the year in a strong financial position with approximately 80% of our bank credit facility undrawn and a trailing 12-month debt to funds flow ratio of 1.4x.

Total debt net of cash at December 31, 2013, including the current portion, was $1,022.3 million compared to $1,064.4 million at December 31, 2012. Total debt was comprised of $214.4 million of bank indebtedness and $810.9 million of senior notes less $3.0 million in cash. Our working capital deficiency, excluding cash and current deferred financial and tax assets and credits, increased to $271.4 million at December 31, 2013 from $173.2 million at December 31, 2012. The increase in our working capital deficit resulted from increased accounts payable balances due to timing of capital spending compared to the fourth quarter of 2012. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our adjusted payout ratio, which is calculated as dividends, net of our SDP and DRIP proceeds, plus capital spending and office capital, divided by funds flow, was 114% for 2013 compared to 174% in 2012. The decrease in our adjusted payout ratio was a result of increased funds flow over the prior year along with reduced capital spending and the reduction in our monthly dividend mid-2012.

Our key leverage ratios are detailed below:

Financial Leverage and Coverage	December 31, 2013	December 31, 2012
Long-term debt to funds flow (trailing 12-month)(1)	1.4 x	1.7 x
Funds flow to interest expense (trailing 12-month)(2)	13.3 x	12.1 x
Long-term debt to long-term debt plus equity(1)	35%	35%

(1) Long-term debt is measured net of cash and includes the current portion of the senior notes.
(2) Interest expense excluding non-cash items.

On November 8, 2013, our $1.0 billion bank credit facility was extended for one year, maturing October 31, 2016. Drawn and undrawn fees improved by 10 basis points across the grid and range between 150 and 315 basis points over Bankers' Acceptance rates. We are currently paying 170 basis points over Bankers' Acceptance rates, which are trading around 1.2%, for a combined rate of approximately 2.9%. At December 31, 2013 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.

Counterparty Credit

OIL AND GAS SALES COUNTERPARTIES

Our oil and 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 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 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, 2013 we had $28.5 million in mark-to-market assets offset by $37.0 million of mark-to-market liabilities resulting in a net liability position of $8.5 million.

Dividends

($ millions, except per share amounts)	2013	2012	2011
Cash dividends[1]	$ 170.7	$ 278.0	$ 388.9
Stock Dividend Plan	46.2	23.6	–
Total dividends to shareholders	$ 216.9	$ 301.6	$ 388.9
Per weighted average share (Basic)	$ 1.08	$ 1.54	$ 2.16

(1) Includes DRIP of $19.2 million in 2012 and $52.4 million in 2011.

We reported a total of $216.9 million or $1.08 per share in dividends to our shareholders in 2013. Dividends during 2012 were $301.6 million or $1.54 per share and during 2011 were $388.9 million or $2.16 per share. We reduced our monthly dividend from $0.18 per share to $0.09 per share, effective for our July 20, 2012 dividend payment. We will continue to assess our dividend levels with respect to anticipated funds flow, debt levels, capital spending plans and capital market conditions and do not anticipate any changes to our dividend at this time.

Participation in the Stock Dividend Plan ("SDP") is optional allowing our shareholders to continue to receive cash dividends unless they elect to receive stock dividends. Currently we have a participation rate of approximately 23% or approximately $4.2 million per month. The SDP serves as a source of capital by allowing us to retain cash that would otherwise be paid out as dividends.

Commitments

As at December 31, 2013 we had the following minimum annual commitments including long-term debt:

		Minimum Annual Commitment Each Year					
($ millions)	Total	2014	2015	2016	2017	2018	Total Committed after 2018
Transportation commitments	$ 102.7	$ 30.4	$ 25.5	$ 13.4	$ 12.0	$ 3.5	$ 17.9
Processing commitments	50.6	10.2	9.6	9.0	8.2	6.8	6.8
Drilling and completions commitment	11.6	11.6	–	–	–	–	–
Power infrastructure	13.9	4.0	7.9	2.0	–	–	–
Office leases	73.0	13.6	11.8	12.1	12.3	12.45	10.7
Total commitments[1][2]	$ 251.8	$ 69.8	$ 54.8	$ 36.5	$ 32.5	$ 22.8	$ 35.4

(1) 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.

(2) US$ commitments have been converted to CDN$ using the December 31, 2013 foreign exchange rate of 1.0636.

For our U.S. Bakken crude oil we have aggregate term pipeline transportation capacity of approximately 8,500 bbl/day from 2014 until April 2016 with 7,500 bbl/day of that continuing through December 2017.

We have contracted up to 191 MMcf/day of natural gas pipeline capacity, some of it in series, with contract terms that range anywhere from one month to five years.

Our Canadian and U.S. office leases expire in 2019. Annual costs of these lease commitments include rent and operating fees. Our commitments, contingencies and guarantees are more fully described in Note 16.

Subsequent to December 31, 2013 we entered into a long-term agreement with a counterparty to provide NGL fractionation services in Western Canada with potential unmitigated demand charges of approximately $18.9 million over the term of the agreement.

Shareholders' Capital

	2013	2012	2011
Share capital ($ millions)	$ 3,061.8	$ 2,997.7	$ 2,622.0
Common shares outstanding (thousands)	202,758	198,684	181,159
Weighted average shares outstanding (thousands)	200,567	195,633	179,889

During 2013 a total of 4,074,000 shares (2012 – 2,816,000; 2011 – 2,510,000) and $61.0 million of additional equity (2012 – $43.9; 2011 – $64.0 million) was issued pursuant to the SDP, our former DRIP and the stock option plan. For further details see Note 14.

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).

At December 31, 2013 we had 202,758,000 shares outstanding (2012 – 198,684,000; 2011 – 181,159,000) and at February 20, 2014 we had 203,121,000 shares outstanding.

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.

The ongoing uncertainty surrounding the direction from government on regulations affects our ability to proactively manage potential risks and opportunities associated with greenhouse gas emissions. We intend to continue to improve energy efficiencies and proactively manage our emissions.

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 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, 2013.

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, NGLs, 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.

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. 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. Refer to the "Price Risk Management" section for further details on our price risk management program.

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 reserve or resource write-downs.

Each year, independent reserves engineers evaluate the majority of our proved and probable reserves as well as 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

Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("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 reserve evaluations have been conducted on approximately 89.5% of the total proved plus probable value (discounted at 10%) of our reserves at December 31, 2013. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 74% 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 properties. Netherland, Sewell & Associates, Inc. (NSAI) evaluated 100% of our U.S. natural gas and shale gas properties.

The evaluations of contingent resources associated with our Wilrich and Fort Berthold assets were conducted by Enerplus and audited by McDaniel. NSAI evaluated 100% of our Marcellus gas reserves and provided the estimate of contingent resources. The contingent resource assessments associated with a portion of our waterflood properties were completed internally by Enerplus' qualified reserve evaluators.

The Reserves Committee and the Board of Directors has reviewed and approved the reserve and resource 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.

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. 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 this 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 2014, 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 are subject to a broad range of regulatory requirements that continue to increase both within Canada and the United States.

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 a 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

The volatile commodity price environment increases 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. 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$175 million, 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. In addition, we have hedged the U.S. dollar interest obligation on our US$175 million notes. At this time we have not entered into any other foreign currency derivatives with respect to our oil and gas sales or our U.S. operations.

Interest Rate Exposure

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

We monitor the interest rate forward market and have fixed the interest rate on approximately 74% 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. 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.

Cash Flow Sensitivity

The sensitivities below reflect all commodity contracts listed in Note 15 and are based on forward markets as at February 4, 2014. To the extent crude oil and natural gas prices change significantly from current levels, the sensitivities will no longer be relevant.

Sensitivity Table(2)	Estimated Effect on 2014 Funds Flow per Share(1)
Change of $0.50 per Mcf in the price of AECO natural gas	$ 0.14
Change of US$5.00 per barrel in the price of WTI crude oil	$ 0.14
Change of 1,000 BOE/day in production	$ 0.02
Change of $0.01 in the US$/CDN$ exchange rate	$ 0.04
Change of 1% in interest rate	$ 0.02

(1) Assumes 204,039,000 weighted average shares outstanding.

2014 GUIDANCE

A summary of our 2014 guidance is below. This guidance does not include any potential acquisitions or divestments.

Summary of 2014 Expectations	Target
Average annual production	96,000 – 100,000 BOE/day
Capital spending	$760 million
Production mix (volumes)	48% crude oil and liquids, 52% natural gas
Operating costs	$10.25/BOE
Cash G&A expenses	$2.45/BOE
Cash share-based compensation expenses	$0.25/BOE
U.S. Cash taxes (% of U.S. funds flow)	3-5%

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, 2013, 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, 2013 and ended December 31, 2013 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 2014 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged; the results from our drilling program and the timing of related production; future oil and natural gas prices and differentials and our commodity risk management programs; 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 2014 and its impact on our production level and land holdings; our ability to reallocate funds within our 2014 capital program; potential future asset impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future 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; the amount and timing of future cash dividends that we may pay to our shareholders; the amount and timing of future debt and equity issuances and expected use of proceeds therefrom; and the amount and timing of future dispositions and acquisitions; and our ability to improve our trading multiple and create significant value for 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; 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; commodity price and cost assumptions; 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. 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; 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; a failure to complete planned asset dispositions on the terms anticipated or at all; 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 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.

REPORTS

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 (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2013, 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, 2013, 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, 2013.

Ian C. Dundas
President and
Chief Executive Officer

Robert J. Waters
Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 20, 2014

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, 2013, based on the criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management's report on internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of 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, 2013, based on the criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2013 of the Company and our report dated February 20, 2014 expressed an unqualified opinion on those financial statements.

Deloitte LLP

Chartered Accountants

February 20, 2014
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 20, 2014. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

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

The consolidated financial statements have been examined by Deloitte LLP, Independent Registered 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 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 20, 2014

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, 2013 and December 31, 2012, 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, 2013, 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, 2013 and December 31, 2012, and their financial performance and their cash flows for each of the years in the three-year period ended December 31, 2013 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, 2013, based on the criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 20, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte LLP

Chartered Accountants

February 20, 2014
Calgary, Canada

Consolidated Balance Sheets

(CDN$ thousands)	Note	December 31, 2013	December 31, 2012
Assets			
Current assets			
Cash		$ 2,990	$ 5,200
Accounts receivable	3	165,091	161,131
Deferred income tax asset	13	48,476	–
Deferred financial assets	15	9,198	54,165
Other current assets		7,641	7,623
		233,396	228,119
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	4	2,420,144	2,315,599
Other capital assets, net	4	21,210	22,196
Property, plant and equipment		2,441,354	2,337,795
Goodwill		609,975	599,716
Deferred income tax asset	13	364,411	437,076
Deferred financial assets	15	19,274	8,013
Marketable securities	6	13,389	7,699
Total Assets		$ 3,681,799	$ 3,618,418
Liabilities			
Current liabilities			
Accounts payable	7	$ 377,157	$ 278,550
Dividends payable		18,250	17,882
Current portion of long-term debt	8	48,713	45,566
Deferred income tax liability	13	–	9,430
Deferred financial credits	15	37,031	18,522
		481,151	369,950
Long-term debt	8	976,585	1,023,999
Deferred financial credits	15	–	17,127
Asset retirement obligation	9	291,761	256,102
		1,268,346	1,297,228
Total Liabilities		1,749,497	1,667,178
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value Issued and outstanding: December 31, 2013 – 203 million shares December 31, 2012 – 199 million shares	14	3,061,839	2,997,682
Paid-in capital	14	38,398	32,293
Accumulated deficit		(1,117,238)	(948,350)
Accumulated other comprehensive income/(loss)		(50,697)	(130,385)
		1,932,302	1,951,240
Total Liabilities & Equity		$ 3,681,799	$ 3,618,418

Commitments, Contingencies and Guarantees 16

See accompanying notes to the Consolidated Financial Statements

Approved on behalf of the Board of Directors:

Douglas R. Martin
Director

Robert B. Hodgins
Director

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

For the year ended December 31 (CDN$ thousands)	**Note**	**2013**	**2012**	**2011**
Revenues				
Oil and natural gas sales, net of royalties	10	$ 1,352,472	$ 1,153,334	$ 1,158,589
Commodity derivative instruments gain/(loss)	15	(41,870)	91,995	(27,092)
		1,310,602	1,245,329	1,131,497
Expenses				
Operating		343,433	319,031	280,425
Production taxes		70,388	56,624	40,092
Transportation		39,918	26,569	20,647
General and administrative	14	110,260	93,844	94,442
Depletion, depreciation, amortization and accretion		593,203	560,293	509,620
Asset impairment	5	–	781,099	209,396
Foreign exchange loss/(gain)	12	9,313	(17,204)	4,216
Interest	11	58,337	54,907	44,938
Other Income	6	(868)	(86,146)	(2,677)
		1,223,984	1,789,017	1,201,099
Income/(loss) before tax expense		86,618	(543,688)	(69,602)
Current income tax expense/(recovery)	13	7,889	1,648	81,195
Deferred income tax expense/(recovery)	13	30,753	(274,639)	(163,608)
Net Income/(loss)		$ 47,976	$ (270,697)	$ 12,811
Other Comprehensive Income/(loss)				
Changes due to marketable securities (net of tax)				
Unrealized gains/(losses)	6	7,136	(10,115)	685
Realized gains reclassified to net income	6	(315)	–	–
Change in cumulative translation adjustment		72,867	(32,255)	11,931
Other Comprehensive Income/(loss)		79,688	(42,370)	12,616
Total Comprehensive Income/(loss)		$ 127,664	$ (313,067)	$ 25,427
Net income/(loss) per share				
Basic	14	$ 0.24	$ (1.38)	$ 0.07
Diluted	14	$ 0.24	$ (1.38)	$ 0.07

See accompanying notes to the Consolidated Financial Statements

Consolidated Statements of Changes in Shareholders' Equity

For the year ended December 31 (CDN$ thousands)	**2013**	**2012**	**2011**
Share Capital			
Balance, beginning of year	$ 2,997,682	$ 2,622,003	$ 2,548,631
Public offering	–	330,618	–
Stock Option Plan – cash	14,838	1,180	11,626
Stock Option Plan – non cash	3,108	1,119	9,371
Dividend Reinvestment Plan	–	19,150	52,375
Stock Dividend Plan	46,211	23,612	–
Balance, end of year	$ 3,061,839	$ 2,997,682	$ 2,622,003
Paid-in Capital			
Balance, beginning of year	$ 32,293	$ 23,115	$ 20,156
Stock Option Plan – exercised	(3,108)	(1,119)	(9,371)
Stock Option Plan – expensed	9,213	10,297	12,330
Balance, end of year	$ 38,398	$ 32,293	$ 23,115
Accumulated Deficit			
Balance, beginning of year	$ (948,350)	$ (376,093)	$ –
Net income/(loss)	47,976	(270,697)	12,811
Dividends	(216,864)	(301,560)	(388,904)
Balance, end of year	$ (1,117,238)	$ (948,350)	$ (376,093)
Accumulated Other Comprehensive Income/(Loss)			
Balance, beginning of year	$ (130,385)	$ (88,015)	$ (100,631)
Changes due to marketable securities (net of tax)			
Unrealized gains/(losses)	7,136	(10,115)	685
Realized gains reclassified to net income	(315)	–	–
Change in cumulative translation adjustment	72,867	(32,255)	11,931
Balance, end of year	$ (50,697)	$ (130,385)	$ (88,015)
Total Shareholders' Equity	$ 1,932,302	$ 1,951,240	$ 2,181,010

See accompanying notes to the Consolidated Financial Statements

Consolidated Statements of Cash Flows

For the year ended December 31 (CDN$ thousands)	**Note**	**2013**	**2012**	**2011**
Operating Activities				
Net income/(loss)		$ 47,976	$ (270,697)	$ 12,811
Non-cash items add/(deduct):				
Depletion, depreciation, amortization and accretion		593,203	560,293	509,620
Asset impairment	5	–	781,099	209,396
Changes in fair value of derivative instruments	15	35,088	(85,163)	(31,920)
Deferred income tax expense/(recovery)	13	30,753	(274,639)	(163,608)
Foreign exchange (gain)/loss on debt and working capital	12	19,747	(7,647)	7,185
Share-based compensation – Stock Option Plan	14	9,213	10,297	12,330
Amortization of debt issue costs and senior note premium		793	(5)	(429)
Derivative settlement on senior notes principal repayment		17,827	18,406	19,119
Asset disposition (gain)/loss	6	(367)	(87,421)	(103)
Asset retirement obligation expenditures	9	(16,606)	(19,905)	(21,656)
Changes in non-cash operating working capital	18	28,851	(88,929)	71,487
Cash flow from operating activities		766,478	535,689	624,232
Financing Activities				
Proceeds from the issuance of shares	14	14,838	350,948	64,001
Cash dividends	14	(170,653)	(277,948)	(388,904)
Change in bank debt		(45,556)	(189,251)	212,732
Repayment of senior notes		(46,814)	(46,236)	(45,523)
Proceeds from senior note issue		–	406,088	–
Derivative settlement on senior notes principal repayment		(17,827)	(18,406)	(19,119)
Changes in non-cash financing working capital		368	(14,727)	451
Cash flow from financing activities		(265,644)	210,468	(176,362)
Investing Activities				
Capital expenditures		(687,905)	(865,296)	(877,767)
Property and land acquisitions		(244,837)	(185,337)	(255,209)
Property dispositions		365,135	245,771	641,190
Sale of marketable securities	6	2,482	146,898	1,544
Changes in non-cash investing working capital		60,604	(90,252)	38,592
Cash flow from investing activities		(504,521)	(748,216)	(451,650)
Effect of exchange rate changes on cash		1,477	1,630	1,035
Change in cash		(2,210)	(429)	(2,745)
Cash, beginning of year		5,200	5,629	8,374
Cash, end of year		$ 2,990	$ 5,200	$ 5,629

See accompanying notes to the Consolidated Financial Statements

NOTES

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 20, 2014.

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, 2013 and 2012 and results of operations for the years ended December 31, 2013, and the 2012 and 2011 comparative periods.

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, 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. 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 resulting from revisions to estimated timing of cash flows, or changes in the credit-adjusted risk-free rate are recognized as a change in the asset retirement obligation and related capitalized asset retirement cost.

Amortization of capitalized decommissioning 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.

g) Income Tax

Income tax expense is comprised of current and deferred income tax. Current income tax is the expected tax payable or refund on taxable income or loss for the year, using rates enacted at the reporting date. Deferred income tax is recognized using the liability method of accounting for income taxes. Under this method, deferred tax is recorded on the temporary differences between the accounting and income tax basis of assets and liabilities, using the enacted income tax rates expected to apply when the temporary differences are expected to reverse. Deferred tax is recognized in net income except to the extent that it relates to items recognized directly in shareholders' equity. Deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. The Company routinely reviews deferred tax assets 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 Company recognizes the financial statement effects of an uncertain tax position when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxation authority. The amount of tax benefit recognized is the largest amount of tax benefit that has a greater than 50 percent likelihood of being realized upon settlement with a taxation authority. The Company recognizes potential penalties and interest related to uncertain tax positions in income tax expense.

The effect of changes in enacted income tax rates or laws, for both current and deferred income tax, is recognized in net income in the period of enactment.

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. 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, such as exchange traded commodity derivatives

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 comprise cash, marketable securities, accounts receivable, accounts payable, dividends payable and debt. Cash is classified as held-for-trading and carried at cost, which approximates fair value due to the short-term nature of the instrument, based on a Level 1 designation. Accounts receivable are classified as loans and receivables and are carried at amortized cost less any allowance for impairment. Accounts payable, dividends payable and long-term debt are classified as other financial liabilities and are carried at amortized cost.

Enerplus holds certain marketable securities in entities involved in the oil and gas industry. 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' 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 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 Stock Option Plan and long-term incentive plans.

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 as options are exercised.

Enerplus' long-term incentive plans include its Restricted Share Unit ("RSU"), Performance Share Unit ("PSU") and Director Share Unit ("DSU") plans. Under Enerplus' RSU plan, employees receive cash 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. Upon vesting, the plan participants receive a cash payment 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 cash 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. Upon vesting, the plan participants receive a cash payment based on the value of the underlying shares plus notional accrued dividends. The payment is subject to a multiplier that ranges from 0 to 2.0 depending on Enerplus' performance compared to the TSX oil and gas index over the vesting period.

Under Enerplus' DSU plan, directors receive cash 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 non-cash retainer value and they vest upon the director leaving the Board. Upon vesting, the plan participants receive a cash payment based on the value of the underlying notional shares plus notional accrued dividends over the vesting period.

Enerplus recognizes a liability for its long-term incentive plans based on their estimated fair value which is determined using the current market price of the Company's shares, accumulated dividends, and estimated performance multipliers, where applicable. The liability is re-measured at each reporting date and on the settlement date with any changes in fair value recorded as share-based compensation, which is included in general and administrative expenses.

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) Recent Pronouncements Issued

As of January 1, 2014 Enerplus will adopt the following FASB accounting standards updates, which have been issued but are not yet effective. The adoption of these standards is not expected to have any material impact on Enerplus' financial statements.

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

3) ACCOUNTS RECEIVABLE

($ thousands)	December 31, 2013	December 31, 2012
Accrued receivables	$ 122,482	$ 107,518
Accounts receivable – trade	36,034	45,657
Current income tax receivable	9,371	10,759
Allowance for doubtful accounts	(2,796)	(2,803)
Total accounts receivable	$ 165,091	$ 161,131

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

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

As at December 31, 2012 ($ thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties	$ 10,658,923	$ 8,343,324	$ 2,315,599
Other capital assets	82,587	60,391	22,196
Total PP&E	$ 10,741,510	$ 8,403,715	$ 2,337,795

5) IMPAIRMENT

($ thousands)	2013	2012	2011
Oil and natural gas properties	$ –	$ 781,099	$ 209,396
Impairment expense	$ –	$ 781,099	$ 209,396

Enerplus did not record any ceiling test impairments on its oil and natural gas properties in 2013. During 2012 and 2011, non-cash impairments totaling $781.1 million and $209.4 million, respectively, were recorded in the United States cost centre due to continued capital spending and declines in the 12-month average trailing natural gas price during 2012. No impairments were recorded to the Canadian cost centre in the comparative periods.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling test as at December 31, 2013, 2012 and 2011:

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
2013	$ 96.94	$ 1.03	$ 93.19	$ 3.67	$ 3.16
2012	94.71	1.00	88.33	2.83	2.35
2011	96.19	0.98	97.30	4.18	3.75

6) MARKETABLE SECURITIES

During the year ended December 31, 2013 Enerplus sold certain publicly traded securities for proceeds of $2.5 million recognizing a gain of $0.4 million. In connection with these sales, realized gains of $0.3 million net of tax 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, including its Laricina shares which were sold for proceeds of $141.0 million and a gain of $86.5 million.

For the year ended December 31, 2013 the change in fair value of publicly listed investments represented unrealized gains of $7.1 million net of tax ($8.2 million before tax). For the year ended December 31, 2012 and 2011 the change in fair value of these investments represented unrealized losses of $10.1 million ($11.9 million before tax) and unrealized gains of $0.7 million ($0.9 million before tax), respectively.

Realized gains are included in Other Income on the Consolidated Income Statements.

7) ACCOUNTS PAYABLE

($ thousands)	December 31, 2013	December 31, 2012
Accrued payables	$ 262,117	$ 184,498
Accounts payable – trade	115,040	94,052
Total accounts payable	$ 377,157	$ 278,550

8) DEBT

($ thousands)	December 31, 2013	December 31, 2012
Current:		
Senior notes	$ 48,713	$ 45,566
	48,713	45,566
Long-term:		
Bank credit facility	$ 214,394	$ 260,950
Senior notes	762,191	763,049
	976,585	1,023,999
Total debt	$ 1,025,298	$ 1,069,565

Bank Credit Facility

Enerplus has an unsecured, covenant-based, $1 billion bank credit facility that matures on October 31, 2016. 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, 2013 Enerplus had $214.4 million drawn and was in compliance with all financial covenants under the facility. During 2013 a fee of $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, 2013 was 2.6% (December 31, 2012 – 2.4%).

Senior Notes

On June 19, 2013 Enerplus made its fourth 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. On October 1, 2013 Enerplus made its third principal repayment and associated foreign exchange swap settlement on the US$54.0 million senior notes for a total of $10.9 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)
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	21,272
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$355,000	377,578
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	42,544
June 18, 2009	June 18 and Dec 18	5 equal annual installments beginning June 18, 2017	7.97%	US$225,000	US$225,000	239,310
Oct 1, 2003	April 1 and Oct 1	5 equal annual installments beginning Oct 1, 2011	5.46%	US$54,000	US$21,600	22,974
June 19, 2002	June 19 and Dec 19	5 equal annual installments beginning June 19, 2010	6.62%	US$175,000	US$35,000	37,226
				Total carrying value		$ 810,904
				Current portion		$ 48,713
				Long-term portion		$ 762,191

9) ASSET RETIREMENT OBLIGATION

At December 31, 2013 Enerplus estimated the present value of its asset retirement obligation to be $291.8 million (December 31, 2012 – $256.1 million) based on a total undiscounted liability of $720.6 million (December 31, 2012 – $659.7 million). The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.96% at December 31, 2013 (December 31, 2012 – 6.15%). Enerplus' asset retirement obligation expenditures are expected to be incurred over the next 66 years with the majority between 2024 and 2053. The change in capitalized asset retirement costs for the year ended December 31, 2013 was $37.3 million (December 31, 2012 – $29.5 million).

($ thousands)	December 31, 2013	December 31, 2012
Balance, beginning of year	$ 256,102	$ 232,139
Change in estimates	44,217	40,843
Property acquisition and development activity	1,454	1,395
Dispositions	(8,362)	(12,721)
Settlements	(16,606)	(19,905)
Accretion expense	14,956	14,351
Balance, end of year	$ 291,761	$ 256,102

10) OIL AND NATURAL GAS SALES

($ thousands)	2013	2012	2011
Oil and natural gas sales	$ 1,616,798	$ 1,365,542	$ 1,363,727
Royalties[1]	(264,326)	(212,208)	(205,138)
Oil and natural gas sales, net of royalties	$ 1,352,472	$ 1,153,334	$ 1,158,589

(1) Royalties above do not include production taxes which are reported separately on the Consolidated Income Statement.

11) INTEREST EXPENSE

($ thousands)	2013	2012	2011
Realized:			
Interest on bank debt and senior notes	$ 56,716	$ 53,074	$ 47,049
Unrealized:			
Cross currency interest rate swap (gain)/loss	1,306	2,963	355
Interest rate swap (gain)/loss	(478)	(1,125)	(2,037)
Amortization of debt issue costs and senior note premium	793	(5)	(429)
Interest expense	$ 58,337	$ 54,907	$ 44,938

12) FOREIGN EXCHANGE

($ thousands)	2013	2012	2011
Realized:			
Foreign exchange (gain)/loss	$ 17,596	$ 6,508	$ 18,421
Unrealized:			
Translation of U.S. dollar debt and working capital	19,747	(7,647)	7,185
Cross currency interest rate swap (gain)/loss	(19,920)	(15,118)	(15,133)
Foreign exchange swap (gain)/loss	(8,110)	(947)	(6,257)
Foreign exchange (gain)/loss	$ 9,313	$ (17,204)	$ 4,216

13) INCOME TAXES

For the year ended December 31, ($ thousands)	2013	2012	2011
Current Tax			
Canada	$ (621)	$ (2,074)	$ 569
United States	8,510	3,722	80,626
Current tax expense/(recovery)	7,889	1,648	81,195
Deferred Tax			
Canada	$ (21,166)	$ 17,720	$ (311)
United States	51,919	(292,359)	(163,297)
Deferred tax expense/(recovery)	30,753	(274,639)	(163,608)
Income tax expense/(recovery)	$ 38,642	$ (272,991)	$ (82,413)

Deferred income tax expense recognized in Other Comprehensive Income totaled $1.0 million for 2013 ($3.0 million recovery in 2012, and $0.1 million expense in 2011) related to marketable securities.

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

($ thousands)	2013	2012	2011
Income/(loss) before taxes			
Canada	$ (74,946)	$ 220,259	$ 113,712
United States	161,564	(763,947)	(183,314)
Total income/(loss) before taxes	$ 86,618	$ (543,688)	$ (69,602)
Canadian statutory rate	25.35%	25.32%	26.82%
Expected income tax expense/(recovery)	$ 21,958	$ (137,662)	$ (18,667)
Impact on taxes resulting from:			
Foreign tax rate differential	$ 10,407	$ (106,858)	$ (35,440)
Statutory and other rate differences	(1,976)	(7,828)	(28,923)
Recognition of previously unrecognized deferred tax assets	(690)	(11,082)	(3,970)
Non-taxable capital (gains)/losses	4,884	(12,248)	(364)
Share-based compensation	2,335	2,574	3,307
Other	1,724	113	1,644
Income tax expense/(recovery)	$ 38,642	$ (272,991)	$ (82,413)

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

($ thousands)	2013	2012
Deferred income tax liabilities		
Property, plant and equipment	$ (62,565)	$ (11,473)
Long-Term debt	(2,154)	(10,825)
Deferred financial assets and credits	–	(10,320)
Other	(7,189)	–
Total deferred income tax liabilities	(71,908)	(32,618)
Deferred income tax assets		
Tax loss carryforwards and other credits	$ 551,331	$ 541,694
Asset retirement obligation	75,677	65,858
Deferred financial assets and credits	2,114	–
Marketable Securities	1,620	2,688
Other	6,697	4,128
Total deferred income tax assets	637,439	614,368
Less valuation allowance	(152,644)	(154,104)
Total deferred income tax assets, net	484,795	460,264
Net deferred income tax asset/(liability)	$ 412,887	$ 427,646

The net deferred income tax asset includes a current deferred income tax asset of $48.5 million (December 31, 2012 – liability of $9.4 million) and a long-term deferred income tax asset of $364.4 million (December 31, 2012 – $437.1 million).

Loss carryforwards and tax credits that can be utilized in future years are as follows:

As at December 31 ($ thousands)	2013	Expiration Date
Canada		
Capital losses	$ 1,208,000	Indefinite
Non-capital losses	445,000	2028-2031
United States		
Net operating losses	463,000	2030-2033
Alternative minimum tax credits	99,000	Indefinite

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

For the years ended December 31 ($ thousands)	2013	2012	2011
Balance, beginning of year	$ 18,500	$ 13,600	$ 13,200
Increase/(decrease) for tax positions of prior years	(500)	4,900	1,000
Lapse of statute of limitations	–	–	(600)
Balance, end of year	$ 18,000	$ 18,500	$ 13,600

If recognized, all of Enerplus' unrecognized tax benefits as at December 31, 2013 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.

Enerplus recognizes accrued interest in respect of unrecognized tax benefits in income tax expense. During 2013, Enerplus recognized an interest recovery of $0.1 million (2012 – expense of $0.3 million; 2011 – expense of $1.5 million). As at December 31, 2013 Enerplus had a liability of $0.2 million (December 31, 2012 – $0.3 million) for interest accrued related to unrecognized tax benefits.

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	2004-2013
United States – Federal & State	2008-2013

Enerplus' group of companies files income tax returns primarily in Canada and the United States. Matters in dispute with the taxation authorities are ongoing and in various stages of completion.

14) SHAREHOLDERS' EQUITY

a) Share Capital

	2013		2012		2011	
Authorized unlimited number of common shares Issued: (thousands)	**Shares**	**Amount**	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	198,684	$ 2,997,682	181,159	$ 2,622,003	178,649	$ 2,548,631
Issued for cash:						
Public offerings	–	–	14,709	330,618	–	–
Dividend Reinvestment Plan	–	–	955	19,150	1,928	52,375
Stock Option Plan	1,042	14,838	68	1,180	582	11,626
Non-cash:						
Stock Dividend Plan	3,032	46,211	1,793	23,612	–	–
Stock Option Plan		3,108	–	1,119	–	9,371
Balance, end of year	202,758	$ 3,061,839	198,684	$ 2,997,682	181,159	$ 2,622,003

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

b) Dividends

($ thousands)	2013	2012	2011
Cash dividends[(1)]	$ 170,653	$ 277,948	$ 388,904
Stock Dividend Plan	46,211	23,612	–
Dividends to shareholders	$ 216,864	$ 301,560	$ 388,904

(1) Includes $19.2 million in 2012 and $52.4 million in 2011 related to the former Dividend Reinvestment Plan.

For the year ended December 31, 2013 Enerplus paid dividends of $1.08 per common share totaling $216.9 million (December 31, 2012 – $1.54 per share and $301.6 million, December 31, 2011 – $2.16 per share and $388.9 million).

c) Share-based compensation

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

($ thousands)	2013	2012	2011
Cash:			
Long-term incentive plans expense	$ 23,262	$ 5,618	$ 14,443
Non-Cash:			
Stock Option Plan expense	9,213	10,297	12,330
Equity swap gain	(5,450)	(412)	–
Share-based compensation expense	$ 27,025	$ 15,503	$ 26,773

(i) Long-Term Incentive Plans

The following table summarizes the PSU, RSU and DSU activity for the year ended December 31, 2013 and other information at December 31, 2013:

For the year ended December 31, 2013 (thousands of units)	PSU	RSU	DSU
Balance, beginning of year	605	963	34
Granted	370	462	78
Vested	(256)	(469)	(13)
Forfeited	(69)	(135)	–
Balance, end of year	650	821	99

At December 31, 2013 (in $thousands, except for years)	PSU	RSU	DSU
Recognized cash share-based compensation expense(1)	$ 14,965	$ 11,271	$ 2,075
Unrecognized cash share-based compensation expense	13,966	6,730	–
Intrinsic value(2)	$ 28,931	$ 18,001	$ 2,075
Weighted-average remaining contractual term (years)(3)	1.6	0.9	–

(1) Recognized amounts are included in accounts payable on the Consolidated Balance Sheets. At December 31, 2013 the plans had a liability balance of $28.3 million.
(2) Includes estimated performance multipliers for the PSU plan. Unrecognized amounts will be recorded to cash share-based compensation expense over the remaining vesting term.
(3) DSU awards vest upon a Director leaving the Board.

For the year ended December 31, 2013 the Company recorded cash share-based compensation costs of $23.3 million (December 31, 2012 – $5.6 million, December 31, 2011 – $14.4 million) and paid $11.1 million on settlements in relation to its long-term incentive plans (December 31, 2012 – $14.0 million, December 31, 2011 – $18.0 million).

(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 following assumptions were used to arrive at the estimates of fair value during each of the respective reporting periods:

Weighted average for the period	December 31, 2013	December 31, 2012	December 31, 2011
Dividend yield(1)	8.0%	8.2%	7.14%
Volatility(1)	27.80%	28.35%	35.00%
Risk-free interest rate	1.51%	1.35%	2.34%
Forfeiture rate	10.0%	10.0%	9.4%
Expected life	4.5 years	4.5 years	4.5 years

(1) Reflects the expected dividend yield and volatility of Enerplus shares over the expected life of the option.

The following table summarizes the stock option plan activity for the year ended December 31, 2013:

Year ended December 31, 2013	Number of Options (thousands)	Weighted Average Exercise Price
Options outstanding, beginning of year	10,768	$ 22.11
Granted	6,158	14.11
Exercised	(1,042)	14.25
Forfeited	(2,208)	22.34
Expired	(262)	44.09
Options outstanding, end of year	13,414	$ 18.65
Options exercisable, end of year	4,185	$ 23.09

At December 31, 2013, 4,185,000 options were exercisable at a weighted average reduced exercise price of $23.09 with a weighted average remaining contractual term of 4.07 years, giving an aggregate intrinsic value of $5.2 million (December 31, 2012 – nil, December 31, 2011 – $4.4 million). The total intrinsic value of options exercised during the year ended December 31, 2013 was $2.7 million (December 31, 2012 – $0.3 million, December 31, 2011 – $6.1 million). The weighted average grant date fair value of options granted for the year ended December 31, 2013 was $8.1 million (December 31, 2012 – $13.5 million, December 31, 2011 – $10.3 million).

At December 31, 2013 the total share-based compensation expense related to non-vested options not yet recognized was $4.6 million. The expense is expected to be recognized in net income over a weighted-average period of 1.3 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)	2013	2012	2011
Balance, beginning of year	$ 32,293	$ 23,115	$ 20,156
Stock Option Plan – exercised	(3,108)	(1,119)	(9,371)
Stock Option Plan – expensed	9,213	10,297	12,330
Balance, end of year	$ 38,398	$ 32,293	$ 23,115

e) Basic and Diluted Earnings Per Share

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

(thousands, except per share amounts)	2013	2012	2011
Net income/(loss)	$ 47,976	$ (270,697)	$ 12,811
Weighted average shares outstanding – Basic	200,567	195,633	179,889
Dilutive impact of options[(1)]	837	–	456
Weighted average shares outstanding – Diluted	201,404	195,633	180,345
Net income/(loss) per share			
Basic	0.24	(1.38)	0.07
Diluted	0.24	(1.38)	0.07

(1) For the year ended December 31, 2012 options are anti-dilutive as their conversion to shares would not increase the loss per share.

15) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At December 31, 2013, 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, 2013 the fair value of marketable securities was $13.4 million (December 31, 2012 – $7.7 million).

At December 31, 2013 senior notes included in long-term debt had a carrying value of $810.9 million and a fair value of $837.8 million (December 31, 2012 – $808.6 million and $896.9 million, respectively). The fair value of senior notes was estimated by discounting future interest and principle payments using available market information at the balance sheet date.

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

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 periods:

Gain/(Loss) ($ thousands)	December 31, 2013	December 31, 2012	December 31, 2011	Income Statement Presentation
Interest Rate Swaps	$ 478	$ 1,125	$ 2,037	Interest Expense
Cross Currency Interest Rate Swap:				
Interest	(1,306)	(2,963)	(355)	Interest Expense
Foreign Exchange	19,920	15,118	15,133	Foreign Exchange
Foreign Exchange Swaps	8,110	947	6,257	Foreign Exchange
Electricity Swaps	758	(3,108)	2,756	Operating Expense
Equity Swaps	5,450	412	–	General and Administrative
Commodity Derivative Instruments:				
Oil	(65,504)	70,283	18,733	Commodity derivative
Gas	(2,994)	3,349	(12,641)	instruments
Total Gain/(Loss)	$ (35,088)	$ 85,163	$ 31,920	

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

($ thousands)	2013	2012	2011
Change in fair value of commodity derivative instruments gain/(loss)	$ (68,498)	$ 73,632	$ 6,092
Net realized cash gain/(loss)	26,628	18,363	(33,184)
Commodity derivative instruments gain/(loss)	$ (41,870)	$ 91,995	$ (27,092)

The following tables summarize the fair values at the respective period ends:

	December 31, 2013				December 31, 2012			
	Assets		Liabilities		Assets		Liabilities	
($ thousands)	Current	Long-term	Current	Long-term	Current	Long-term	Current	Long-term
Interest Rate Swaps	$ –	$ –	$ –	$ –	$ –	$ –	$ 478	$ –
Cross Currency Interest Rate Swap	–	–	15,548	–	–	–	17,035	17,127
Foreign Exchange Swaps	564	15,135	–	–	–	7,745	156	–
Electricity Swaps	–	–	95	–	–	–	853	–
Equity Swaps	1,723	4,139	–	–	144	268	–	–
Commodity Derivative Instruments:								
Oil	4,138	–	18,970	–	50,672	–	–	–
Gas	2,773	–	2,418	–	3,349	–	–	–
Total	$ 9,198	$ 19,274	$ 37,031	$ –	$ 54,165	$ 8,013	$ 18,522	$ 17,127

c) Risk Management

(i) Market Risk

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

Commodity Price Risk:

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

The following tables summarize Enerplus' price risk management positions at February 4th, 2014:

Crude Oil Instruments:

Instrument Type	bbls/day	US$/bbl(1)
Jan 1, 2014 – Jan 31, 2014		
WTI Swap	23,000	93.98
WCS Differential Swap	1,000	(23.25)
Feb 1, 2014 – Jun 30, 2014		
WTI Swap	23,000	93.98
WCS Differential Swap	2,000	(21.88)
Jul 1, 2014 – Dec 31, 2014		
WTI Swap	16,000	94.07
WCS Differential Swap	2,000	(21.88)
Jan 1, 2015 – Dec 31, 2015		
WTI Swap	500	90.00

(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$/Mcf	US$/Mcf
Jan 1, 2014 – Dec 31, 2014			
AECO Swap	4.7	3.96	
Apr 1, 2014 – Jun 30, 2014			
AECO Swap	14.2	4.12	
Jul 1, 2014 – Dec 31, 2014			
AECO Swap	28.4	4.25	
Jan 1, 2014 – Dec 31, 2014			
NYMEX Swap	75.0		4.14
NYMEX Purchased Call	25.0		4.17
NYMEX Sold Puts	25.0		3.23
NYMEX Sold Calls	25.0		5.00
Jan 1, 2015 – Dec 31, 2015			
NYMEX Swap	20.0		4.16

Electricity:

Instrument Type	MWh	CDN$/MWh
Jan 1, 2014 – Dec 31, 2014		
AESO Power Swap(1)	16.0	53.33
Jan 1, 2015 – Dec 31, 2015		
AESO Power Swap(1)	10.0	51.13

(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"):

Concurrent with the issuance of the US$175 million senior notes on June 19, 2002, Enerplus entered into a CCIRS with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal payments at a notional amount of CDN$268.3 million. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%. At December 31, 2013 the remaining USD principal is fixed at a notional amount of CDN$53.7 million. The CCIRS matures on June 2014 in conjunction with the remaining principal repayment on the notes.

Foreign Exchange Swaps:

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. At December 31, 2013, following the third settlement, Enerplus had US$21.6 million of remaining notional debt swapped. These foreign exchange swaps mature between October 2014 and October 2015 in conjunction with the remaining principal repayments 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, 2013, approximately 74% of Enerplus' debt was based on fixed interest rates and 26% was based on floating interest rates. At December 31, 2013, Enerplus did not have any interest rate derivatives outstanding other than the CCIRS mentioned above.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its cash settled long-term incentive plans detailed in Note 13.

Equity Swaps:

Enerplus has entered into various equity swaps maturing between 2014 and 2016 and has effectively fixed the future settlement cost at a weighted average price of $13.86 per share on 1,130,000 shares, representing approximately 77% of the notional shares outstanding under these plans.

(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, 2013 approximately 71% of Enerplus' marketing receivables were with companies considered investment grade.

At December 31, 2013 approximately $4.5 million or 3% 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, 2013 was $2.8 million (December 31, 2012 – $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.

16) COMMITMENTS, CONTINGENCIES AND GUARANTEES

a) Commitments

Enerplus has the following minimum annual commitments at December 31, 2013:

($ thousands)	Total	2014	2015	2016	2017	2018	Thereafter
		Minimum Annual Commitment Each Year					
Transportation commitments	$ 102,677	$ 30,416	$ 25,486	$ 13,383	$ 11,988	$ 3,525	$ 17,879
Processing commitments	50,593	10,250	9,570	9,054	8,179	6,770	6,770
Drilling and completions	11,582	11,582	–	–	–	–	–
Power infrastructure	13,913	4,020	7,914	1,979	–	–	–
Office leases	73,056	13,611	11,819	12,109	12,348	12,459	10,710
Total commitments(1)(2)	$ 251,821	$ 69,879	$ 54,789	$ 36,525	$ 32,515	$ 22,754	$ 35,359

(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, 2013 foreign exchange rate of 1.0636.

Transportation for Enerplus' Bakken crude oil in the U.S. has been contracted for 8,500 bbl/day up until April 2016 with 7,500 bbl/day of that continuing through December 2017.

Enerplus has contracted up to 191 MMcf/day of natural gas pipeline capacity with contract terms ranging from one month to 5 years.

Enerplus has office lease commitments for both its Canadian and U.S. operations that expire in 2019. The annual costs of these lease commitments include rent and operating fees.

b) Contingencies

Enerplus is subject to various legal claims and actions arising in the normal course of business. Although the outcome of such claims and actions cannot be predicted with certainty, the Company does not expect these matters to have a material impact on the Consolidated Financial Statements. In instances where the Company determines that a loss is probable and the amount can be reasonably estimated, an accrual is recorded.

c) Guarantees

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

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

17) GEOGRAPHICAL INFORMATION

As at and for the year ended December 31, 2013 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales	$ 676,502	$ 675,970	$ 1,352,472
Plant, property 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
Plant, property and equipment	1,323,850	1,013,945	2,337,795
Goodwill	451,121	148,595	599,716

18) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	December 31, 2013	December 31, 2012	December 31, 2011
Accounts receivable	$ (6,935)	$ (34,384)	$ (4,333)
Other current assets	(1,156)	4,007	38,223
Accounts payable	36,942	(58,552)	37,597
	$ 28,851	$ (88,929)	$ 71,487

b) Other

($ thousands)	December 31, 2013	December 31, 2012	December 31, 2011
Income taxes paid	$ 4,448	$ 17,946	$ 49,592
Interest paid	$ 55,957	$ 49,826	$ 47,756

5 YEAR DETAILED STATISTICAL REVIEW

	2013	2012	2011	2010[1]	2009[1]
Daily Production					
Crude oil (bbls/day)	38,250	36,509	30,181	31,135	32,984
NGLs (bbls/day)	3,472	3,627	3,306	3,889	4,157
Natural gas (Mcf/day)	288,423	251,773	251,068	288,692	326,570
BOE per day	89,793	82,098	75,332	83,139	91,569
Drilling Activity (net wells)	62	75	107	225	313
Average Benchmark Pricing					
WTI crude oil (US$ per bbl)	$ 97.97	$ 94.21	$ 95.12	$ 79.53	$ 61.80
AECO natural gas – monthly (per Mcf)	3.16	2.40	3.68	4.13	4.14
NYMEX natural gas – monthly (US$ per Mcf)	3.67	2.80	4.07	4.42	4.03
US/CDN exchange Rate	1.03	1.00	0.99	1.03	1.14
Realized Pricing					
Crude oil (per bbl)	$ 83.99	$ 78.19	$ 83.48	$ 70.38	$ 58.54
Natural gas liquids (per bbl)	52.25	53.01	64.99	51.41	41.54
Natural gas (per Mcf)	3.26	2.39	3.72	4.05	3.91
Average realized price (per BOE)	48.11	44.56	48.85	42.85	36.89

($ thousands, except per share amounts)	2013	2012	2011	2010[1]	2009[1]
Financial[1]					
Oil and natural gas sales[5]	$1,576,878	$1,338,973	$1,343,079	$1,300,181	$1,232,763
Funds flow	754,233	644,523	574,401	728,968	763,386
Cash flow from operating activities	766,478	535,689	624,232	696,183	775,786
Cash and stock dividends to shareholders	216,864	301,560	388,904	384,127	368,201
Per share	1.08	1.62	2.16	2.16	2.23
Capital spending	681,437	853,435	866,504	536,436	299,111
Property and land acquisitions	244,837	185,337	255,209	1,012,272	271,977
Property Divestitures	365,135	275,771	641,190	871,458	104,325
Total net capital expenditures[3]	567,607	774,862	491,786	681,254	473,517
Total assets	3,681,799	3,856,083	5,723,312	5,489,181	5,905,516
Long-term debt, net of cash	973,595	1,018,799	901,465	724,031	485,349
Adjusted payout ratio[4]	114%	174%	212%	123%	85%
Net debt/funds flow ratio	1.4x	1.7x	1.6x	1.0x	0.6x
Oil and Gas Economics					
Net royalty rate	21%	20%	18%	17%	17%
Average realized price[5]	$ 48.11	$ 44.56	$ 48.85	$ 42.85	$ 36.89
Commodity derivative instruments[6]	0.81	0.61	(1.21)	1.64	4.66
Average realized price[2]	48.92	45.17	47.64	44.49	41.55
Net royalty & production tax expense	10.21	8.95	8.92	7.36	6.21
Operating expense[6]	10.50	10.51	10.30	9.66	9.71
Operating netback	28.21	25.71	28.42	27.47	25.63
General and administrative expense[6]	3.25	2.79	2.99	2.76	2.44
Interest, foreign exchange and other expenses[6]	1.71	1.42	1.59	1.69	0.34
Taxes	0.24	0.05	2.95	(1.00)	0.01
Funds flow	$ 23.01	$ 21.45	$ 20.83	$ 24.02	$ 22.84

($ thousands, except per share amounts)	2013	2012	2011	2010[1]	2009[1]
Reserves					
Proved Reserves[7]					
Crude oil (Mbbls)	118,611	124,759	116,664	109,706	120,936
NGLs (Mbbls)	8,967	9,236	9,215	8,610	10,753
Natural gas (MMcf)	409,830	413,906	476,887	554,090	746,034
Shale gas (MMcf)	411,431	146,127	92,682	52,225	8,127
MBOE	264,455	227,335	220,807	219,369	257,382
Probable Reserves[7]					
Crude oil (Mbbls)	73,635	66,913	54,497	40,147	36,410
NGLs (Mbbls)	5,757	5,387	4,411	2,966	3,754
Natural gas (MMcf)	183,744	198,727	192,363	198,097	267,146
Shale gas (MMcf)	189,430	78,373	60,861	64,437	16,763
MBOE	141,587	118,483	101,112	86,868	87,482
Proved Plus Probable Reserves[7]					
Crude oil (Mbbls)	192,246	191,672	171,161	149,853	157,346
NGLs (Mbbls)	14,723	14,623	13,626	11,576	14,507
Natural gas (MMcf)	593,574	612,634	669,250	752,187	1,013,180
Shale gas (MMcf)	600,861	224,500	153,543	116,662	24,890
MBOE	406,042	345,817	321,919	306,237	344,864
Reserve Life Index[8]					
Proved (years)	7.6	7.8	7.7	8.2	8.2
Proved plus probable (years)	10.8	10.9	9.8	10.7	10.9
Trading Information[9]					
Canadian trading summary[10]					
High	$ 19.96	$ 26.94	$ 32.83	$ 31.85	$ 28.00
Low	12.26	11.53	23.00	18.22	16.75
Close	19.30	12.90	25.85	30.67	24.21
Volume	214,057	270,710	180,917	127,386	98,597
U.S. trading summary[11]					
High	$ 18.79	$ 26.54	$ 33.29	$ 31.83	$ 25.13
Low	12.03	11.35	21.65	13.76	12.85
Close	18.18	12.96	25.32	30.84	22.96
Volume	192,733	386,690	225,858	168,979	191,405
Weighted average number of shares outstanding (basic)	200,567	195,633	179,889	175,736	169,280
Number of shares outstanding at December 31	202,758	198,684	181,159	176,946	177,061

(1) 2009 and prior comparatives prepared in accordance with previous Canadian GAAP. 2010 restated in accordance with IFRS. All other data prepared in accordance with U.S. GAAP.
(2) Net of transportation and includes the effects of commodity derivative instruments.
(3) Includes office capital.
(4) Calculated as the sum of dividends net of DRIP and SDP to shareholders and capital expenditures, divided by funds flow.
(5) Net of transportation and before the effects of commodity derivative instruments.
(6) Does not include non-cash portion of expense.
(7) 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 Reserve 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 reserve engineering reports.
(9) 2011 and 2012 – share trading information. Prior to 2011 – Trust Units trading information.
(10) TSX data prior to 2010, Canadian composite trading data including TSX thereafter.
(11) NYSE data prior to 2008, U.S. composite trading data including NYSE thereafter.

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 reserve evaluations have been conducted on approximately 89.5% of the total proved plus probable value (before tax, discounted at 10%) of our reserves at December 31, 2013. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 74% of our Canadian reserves and 100% of the reserves associated with our U.S. oil properties. McDaniel also reviewed the internal evaluation completed by Enerplus on the remaining 26% of our Canadian reserves. Netherland, Sewell & Associates, Inc. ("NSAI") evaluated all of our U.S. natural gas and shale gas properties.

The following reserves information sets out our company interest reserves volumes at December 31, 2013 by production type and reserve 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. Company interest reserves consist of gross reserves, which are before the deduction of any royalties, plus Enerplus' royalty interests in reserves. 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, 2013 were based upon forecast crude oil and natural gas pricing assumptions prepared by McDaniel as of January 1, 2014. 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 2014 Forecast Price Assumptions

	WTI Crude Oil US$/bbl	Light Crude Oil Edmonton(1) CDN$/bbl	Hardisty Heavy Oil 12° API CDN$/bbl	Henry Hub Gas Price US$/MMBtu	Natural Gas 30 day spot @ AECO CDN$/MMBtu	Exchange Rate US$/CDN$
2014	95.00	95.00	67.50	4.25	4.00	0.950
2015	95.00	96.50	70.40	4.50	4.25	0.950
2016	95.00	97.50	71.20	4.75	4.55	0.950
2017	95.00	98.00	71.50	5.00	4.75	0.950
2018	95.30	98.30	71.80	5.25	5.00	0.950
Thereafter	**	**	**	**		0.950

(1) Edmonton Light Sweet 40 degree API, 0.3% sulphur content crude.
** Escalation varies after 2018.

Reserves Summary

Enerplus' 2P reserves increased by 60.2 million BOE to 406.0 million BOE at year-end 2013, up from 345.8 million at year-end 2012. The majority of reserve additions were associated with our U.S. properties as a result of our drilling and acquisition activities. These assets now represent 58% of total 2P reserves. Proved reserves as a percentage of total 2P reserves remained at 65% year-over-year.

Reserves Summary	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Company Interest							
Proved producing	64,108	26,700	90,808	7,348	354,385	212,770	192,681
Proved developed non-producing	805	136	941	145	8,486	72,320	14,553
Proved undeveloped	22,883	3,980	26,863	1,475	46,959	126,342	57,221
Total proved	87,795	30,816	118,611	8,967	409,830	411,431	264,455
Total probable	62,371	11,264	73,635	5,757	183,744	189,430	141,587
Proved plus probable	**150,166**	**42,080**	**192,246**	**14,723**	**593,574**	**600,861**	**406,042**
Gross							
Proved producing	64,006	26,689	90,695	7,166	338,646	212,770	189,764
Proved developed non-producing	805	136	941	144	8,417	72,320	14,541
Proved undeveloped	22,879	3,980	26,859	1,422	43,215	126,342	56,540
Total proved	87,689	30,806	118,495	8,732	390,280	411,431	260,844
Total probable	62,340	11,260	73,600	5,629	174,445	189,430	139,875
Proved plus probable	**150,029**	**42,066**	**192,095**	**14,361**	**564,725**	**600,861**	**400,720**
Net							
Proved producing	53,604	21,407	75,011	5,398	305,107	170,423	159,663
Proved developed non-producing	700	106	806	104	6,335	57,893	11,614
Proved undeveloped	18,654	3,053	21,707	1,172	42,789	101,084	46,858
Total proved	72,957	24,566	97,523	6,674	354,231	329,400	218,136
Total probable	50,388	8,588	58,976	4,459	158,767	151,530	115,152
Proved plus probable	**123,345**	**33,154**	**156,499**	**11,134**	**512,998**	**480,930**	**333,288**

Reserve Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a company interest basis, from December 31, 2012 to December 31, 2013.

PROVED RESERVES – COMPANY INTEREST 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 Dec. 31, 2012	36,246	31,521	67,767	6,887	361,158	–	134,847
Acquisitions	1,580	–	1,580	19	1,676	–	1,879
Dispositions	(7,105)	–	(7,105)	(599)	(5,999)	–	(8,703)
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	1,511	1,528	3,039	196	24,172	–	7,264
Economic factors	491	55	546	(29)	(3,058)	–	8
Technical revisions	(105)	828	722	878	32,791	–	7,065
Production	(3,404)	(3,115)	(6,520)	(1,023)	(64,195)	–	(18,241)
Proved Reserves at Dec. 31, 2013	29,214	30,816	60,030	6,330	346,545	–	124,118

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 Dec. 31, 2012	56,993	–	56,993	2,349	52,748	146,127	92,488
Acquisitions	30	–	30	2	12	117,668	19,645
Dispositions	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	5,188	–	5,188	255	5,177	168,634	34,412
Economic factors	(556)	–	(556)	2	(1,126)	(17,140)	(3,598)
Technical revisions	4,368	–	4,368	273	12,778	30,917	11,924
Production	(7,442)	–	(7,442)	(245)	(6,305)	(34,775)	(14,533)
Proved Reserves at Dec. 31, 2013	58,581	–	58,581	2,637	63,285	411,431	140,337

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 Dec. 31, 2012	93,239	31,521	124,760	9,236	413,906	146,127	227,335
Acquisitions	1,610	–	1,610	21	1,688	117,668	21,524
Dispositions	(7,105)	–	(7,105)	(599)	(5,999)	–	(8,703)
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	6,699	1,528	8,227	451	29,349	168,634	41,675
Economic factors	(65)	55	(10)	(26)	(4,183)	(17,140)	(3,590)
Technical revisions	4,262	828	5,090	1,151	45,569	30,917	18,989
Production	(10,846)	(3,115)	(13,961)	(1,267)	(70,499)	(34,775)	(32,774)
Proved Reserves at Dec. 31, 2013	87,795	30,816	118,611	8,967	409,830	411,431	264,455

PROBABLE RESERVES – COMPANY INTEREST 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 Dec. 31, 2012	12,810	10,991	23,801	3,144	171,526	–	55,533
Acquisitions	290	–	290	3	283	–	340
Dispositions	(2,775)	–	(2,775)	(214)	(2,164)	–	(3,350)
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	687	1,751	2,438	70	8,489	–	3,923
Economic factors	(13)	57	45	(18)	(937)	–	(129)
Technical revisions	(1,320)	(1,536)	(2,856)	(421)	(32,227)	–	(8,649)
Production	–	–	–	–	–	–	–
Probable Reserves at Dec. 31, 2013	9,679	11,264	20,943	2,564	144,970	–	47,668

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 Dec. 31, 2012	43,111	–	43,111	2,243	27,202	78,373	62,950
Acquisitions	681	–	681	40	266	25,686	5,046
Dispositions	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–
Extensions & improved tecovery	14,477	–	14,477	986	12,973	89,619	32,562
Economic factors	8	–	8	2	(19)	(8,877)	(1,473)
Technical revisions	(5,585)	–	(5,585)	(78)	(1,647)	4,629	(5,166)
Production	–	–	–	–	–	–	–
Probable Reserves at Dec. 31, 2013	52,692	–	52,692	3,193	38,774	189,430	93,919

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 Dec. 31, 2012	55,921	10,991	66,912	5,387	198,728	78,373	118,482
Acquisitions	971	–	971	43	548	25,686	5,386
Dispositions	(2,775)	–	(2,775)	(214)	(2,164)	–	(3,350)
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	15,164	1,751	16,916	1,056	21,462	89,619	36,485
Economic factors	(5)	57	53	(16)	(956)	(8,877)	(1,602)
Technical revisions	(6,905)	(1,536)	(8,441)	(499)	(33,874)	4,629	(13,815)
Production	–	–	–	–	–	–	–
Probable Reserves at Dec. 31, 2013	62,371	11,264	73,635	5,757	183,744	189,430	141,587

PROVED PLUS PROBABLE RESERVES – COMPANY INTEREST 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 Dec. 31, 2012	49,056	42,512	91,568	10,031	532,684	–	190,380
Acquisitions	1,870	–	1,870	23	1,959	–	2,219
Dispositions	(9,880)	–	(9,880)	(813)	(8,163)	–	(12,053)
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	2,198	3,279	5,477	266	32,661	–	11,186
Economic factors	478	113	591	(46)	(3,995)	–	(121)
Technical revisions	(1,426)	(708)	(2,134)	457	564	–	(1,583)
Production	(3,404)	(3,115)	(6,520)	(1,023)	(64,195)	–	(18,241)
Proved Plus Probable Reserves at Dec. 31, 2013	38,893	42,080	80,973	8,894	491,515	–	171,787

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 Dec. 31, 2012	100,104	–	100,104	4,592	79,950	224,500	155,438
Acquisitions	711	–	711	42	277	143,354	24,691
Dispositions	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–
Extensions & improved recovery	19,665	–	19,665	1,241	18,150	258,253	66,974
Economic factors	(548)	–	(548)	4	(1,145)	(26,017)	(5,071)
Technical revisions	(1,217)	–	(1,217)	196	11,131	35,545	6,758
Production	(7,442)	–	(7,442)	(245)	(6,305)	(34,775)	(14,533)
Proved Plus Probable Reserves at Dec. 31, 2013	111,273	–	111,273	5,830	102,059	600,861	234,256

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 Dec. 31, 2012	149,160	42,512	191,672	14,623	612,634	224,500	345,817
Acquisitions	2,581	–	2,581	64	2,236	143,354	26,910
Dispositions	(9,880)	–	(9,880)	(813)	(8,163)	–	(12,053)
Discoveries	–	–	–	–	–	–	–
Extensions & improved Recovery	21,864	3,279	25,143	1,507	50,811	258,253	78,160
Economic factors	(70)	113	43	(42)	(5,139)	(26,017)	(5,192)
Technical revisions	(2,643)	(708)	(3,351)	652	11,695	35,545	5,174
Production	(10,846)	(3,115)	(13,961)	(1,267)	(70,499)	(34,775)	(32,774)
Proved Plus Probable Reserves at Dec. 31, 2013	150,166	42,080	192,246	14,724	593,574	600,861	406,042

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 costs generally reflect the total finding and development costs related to reserve additions for that year.

The increase in FDC year-over-year is a result of the increase in the number of undeveloped drilling locations at Fort Berthold, the Marcellus, in the Wilrich and in our Canadian waterflood properties.

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

Future Development Capital ($ millions)	**Proved Reserves**	**Proved Plus Probable Reserves**
2014	479	558
2015	390	518
2016	31	439
2017	31	376
2018	19	40
Remainder	51	65
Total FDC Undiscounted	1,001	1,996
Total FDC Discounted at 10%	889	1,667

F&D and FD&A Costs – including future development capital

($ millions except for per BOE amounts)	**2013**	**2012**	**2011**	**3 Year**
Proved Plus Probable Reserves				
Finding & Development Costs				
Capital Expenditures	$ 681.4	$ 852.8	$ 829.8	$ 2,364.0
Net change in Future Development Capital	$ 200.0	$ 534.6	$ 435.9	$ 1,170.5
Company Interest Reserve additions (MMBOE)	78.1	57.3	48.2	$ 183.6
F&D costs ($/BOE)	$ 11.28	$ 24.21	$ 26.26	$ 19.25
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$ 561.1	$ 726.4	$ 370.2	$ 1,657.7
Net change in Future Development Capital	$ 216.6	$ 509.1	$ 402.7	$ 1,128.4
Company Interest Reserve additions (MMBOE)	93.0	53.9	43.2	$ 190.1
FD&A costs ($/BOE)	$ 8.36	$ 22.92	$ 17.89	$ 14.66
Proved Reserves				
Finding & Development Costs				
Capital Expenditures	$ 681.4	852.8	829.8	$ 2,364.0
Net change in Future Development Capital	$ (106.4)	248.3	230.7	$ 372.6
Company Interest Reserve additions (MMBOE)	57.1	38.4	31.5	$ 127.0
F&D costs ($/BOE)	$ 10.08	$ 28.67	$ 33.67	$ 21.55
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$ 561.1	726.4	370.2	$ 1,657.7
Net change in Future Development Capital	$ (112.8)	241.3	213.0	$ 341.5
Company Interest Reserve additions (MMBOE)	69.9	36.6	28.9	$ 135.4
FD&A costs ($/BOE)	$ 6.41	$ 26.44	$ 20.18	$ 14.77

ECONOMIC, BEST ESTIMATE CONTINGENT RESOURCE ASSESSMENT

The following table provides a breakdown of the economic, best estimate contingent resources associated with a portion of our Fort Berthold, Marcellus, Wilrich and Canadian waterflood assets as at December 31, 2013. These estimates are all economic using current commodity prices and using established technologies.

The evaluation of contingent resources associated with the Wilrich and our leases at Fort Berthold was conducted by Enerplus and audited by McDaniel. NSAI evaluated 100% of our Marcellus shale gas assets in the U.S. and provided the estimate of contingent resources. The contingent resource assessments associated with a portion of our waterflood properties were completed internally by qualified reserve evaluators.

Contingent Resources	"Best Estimate" Contingent Resources	Contingent Resource Net Drilling Locations
Canada		
Crude oil – IOR/EOR on a portion of waterfloods (MMbbls)	58.9	114
Natural gas – Wilrich (Bcfe)	252.6	51
Total Canada (MMBOE)	**101.0**	**165**
United States		
Crude oil and NGLs – Fort Berthold (MMBOE)	38.5	47
Natural gas – Marcellus (Bcf)	1340.3	205
Total United States (MMBOE)	**261.9**	**252**
Total Company (MMBOE)	**362.9**	**417**

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.

While the near-term oil and natural gas price assumptions used by our independent reserve evaluators at January 1, 2014 increased, the long-term price outlooks decreased when compared to the price assumptions used at December 31, 2012. As a result, despite a 17% increase in our 2P reserves at December 31, 2013, the estimated before tax NPV using a 10% discount increased by only 7%.

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

Reserves at December 31, 2013, ($ Millions, discounted at)	0%	5%	10%	15%
Proved developed producing	$ 5,238	$ 3,820	$ 3,051	$ 2,575
Proved developed non-producing	299	217	174	147
Proved undeveloped	1,305	612	312	152
Total Proved	$ 6,842	$ 4,649	$ 3,537	$ 2,874
Probable	4,933	2,382	1,437	974
Total Proved Plus Probable Reserves (before tax)	$ 11,775	$ 7,031	$ 4,974	$ 3,848

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 reserve 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 reserve engineers.

In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserve reports with no further acquisitions or incremental development, including development of contingent resources. At December 31, 2013, the estimate of contingent resources contained within our leases was 363 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.

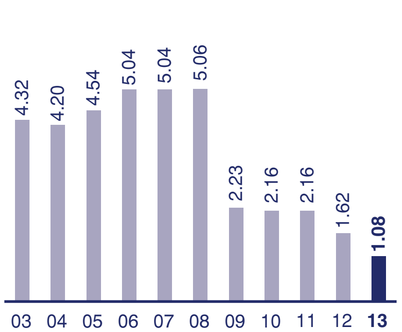
Net Asset Value (Forecast Prices and Costs at December 31, 2013)

($ millions except share amounts, discounted at)	0%	5%	10%	15%
Net present value of proved plus probable reserves (before tax)	$11,775	$7,031	$4,974	$3,848
Undeveloped acreage (2013 Year End)(1)	495	495	495	495
Asset retirement obligations(2)	(412)	(199)	(66)	(24)
Long-term debt, including current portion (net of cash)	(1,022)	(1,022)	(1,022)	(1,022)
Net working capital	(237)	(237)	(237)	(237)
Net Asset Value	**$10,599**	**$6,068**	**$4,144**	**$3,060**
Net Asset Value per Share(3)	**$52.27**	**$29.93**	**$20.44**	**$15.09**

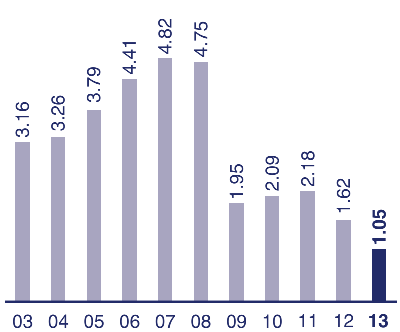
(1) Acreage acquired from 2008 to present valued at acquisition cost. Balance of undeveloped acreage valued at $100/acre.
(2) Asset retirement obligations ("ARO") do not equal the amount on the balance sheet ($291.8 million) as the balance sheet amount uses a 5.96% discount rate and a portion of the ARO costs are already reflected in the present value of reserves computed by the independent engineers.
(3) Based on 202,758,000 shares outstanding as at December 31, 2013.

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

Bcfe billion cubic feet equivalent

BOE barrels of oil equivalent

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

F&D Costs finding and development costs

FD&A Costs finding, development and acquisition costs

FDC future development capital

IFRS International Financial Reporting Standards

LTI long-term incentive

Mbbls thousand barrels

MBOE thousand barrels of oil equivalent

Mcf thousand cubic feet

Mcfe thousand cubic feet equivalent

MMbbl(s) million barrels

MMBOE million barrels of oil equivalent

MMBtu million British Thermal Units

MMcf million cubic feet

MSW mixed sweet blend

MWh megawatt hour(s) of electricity

NGLs natural gas liquids

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

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

OCI other comprehensive income

PDP Reserves proved developed producing reserves

P+P Reserves proved plus probable reserves

RLI reserve life index

SBC share-based compensation

U.S. GAAP United States generally accepted accounting principles

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

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.

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 exploration and development expenditures, exclusive of acquisitions or divestments, and including changes in future development capital, divided by the applicable reserve 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 exploration and development capital expenditures and net acquisitions, including changes in future development capital, divided by reserve 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 Future Development Capital is defined as those costs which reflect the evaluator's best estimate of what it will cost to bring the proved and proved plus probable undeveloped reserves on production in the future. Changes to this figure occur annually as a result of development activities, acquisition and disposition activities, 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, 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.

Reserve 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 engineering reserve report.

Reserve 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 engineering reserve report.

Reserves, Company Interest Our working interest (operated and non-operated) share of reserves before the deduction of any royalty interest reserves, but inclusive of any royalty interest reserves owned by Enerplus. Unless otherwise stated, reserve volumes utilized in any discussions or calculations are company interest reserves. "Company interest" is not a term defined in National Instrument 51-101 adopted by the Canadian Securities regulatory authorities and does not have a standardized meaning under NI 51-101 and therefore disclosure of our company interest reserves may not be comparable to disclosure of reserves by other issuers.

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, Proved 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, Proved 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, Proved 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

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President & Chief Executive Officer
Logan International Inc.
Houston, Texas

Edwin V. Dodge(9)(12)
Corporate Director
Vancouver, British Columbia

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

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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

David O'Brien(3)
Corporate Director
Calgary, Alberta

Elliott Pew(5)(8)
Corporate Director
Boerne, Texas

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

Sheldon B. Steeves(5)(7)
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) Chairman of the Corporate Governance & Nominating Committee
(5) Member of the Audit & Risk Management Committee
(6) Chairman of the Audit & Risk Management Committee
(7) Member of the Reserves Committee
(8) Chairman of the Reserves Committee
(9) Member of the Compensation & Human Resources Committee
(10) Chairman of the Compensation & Human Resources Committee
(11) Member of the Safety & Social Responsibility Committee
(12) Chairman of the Safety & Social Responsibility Committee

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

H. Gordon Love
Vice President, Technical & Operations Services

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

Edward L. McLaughlin
President, U.S. Operations

Christopher M. Stephens
Vice President, Canadian Assets

P. Scott Walsh
Vice President, Information & Corporate Services

Kenneth W. Young
Vice President, Land

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 Reserve Engineers
McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

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

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

Telephone: 720.279.5500
Fax: 720.279.5550

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

Friday, May 9, 2014
10:00 am, MT
The Metropolitan Centre
Lecture Theatre
333 – 4th Avenue SW
Calgary, Alberta

Why invest in Enerplus?

Enerplus is a North American energy producer with a portfolio of oil and gas assets in resource plays that offer organic growth potential with superior economics. We are focused on creating value for our investors through the execution of a disciplined capital investment strategy that allows the successful development of our properties, supported by a strong financial plan. We are a responsible developer of resources that strives to provide investors with a competitive return comprised of both growth and income.

enerPLUS

www.enerplus.com

Toll Free 1.800.319.6462
investorrelations@enerplus.com

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

ERF LISTED ON TMX Toronto Stock Exchange

ERF LISTED NYSE