Q3/13

ENERPLUS THIRD QUARTER REPORT
NINE MONTHS ENDED SEPTEMBER 30, 2013

SELECTED FINANCIAL RESULTS	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Financial (000's)				
Funds Flow	$ 196,187	$ 134,980	$ 573,489	$ 444,233
Cash and Stock Dividends	54,405	53,394	162,199	247,988
Net Income	34,020	(63,466)	81,404	2,977
Debt Outstanding – net of cash	964,577	1,118,569	964,577	1,118,569
Capital Spending	145,811	166,988	458,399	692,641
Property and Land Acquisitions	15,792	7,277	71,451	63,946
Property Dispositions	124,462	3,112	197,086	55,636
Debt to Trailing 12 Month Funds Flow	1.2x	1.9x	1.2x	1.9x
Financial per Weighted Average Shares Outstanding				
Funds Flow	$ 0.98	$ 0.68	$ 2.87	$ 2.28
Net Income	0.17	(0.32)	0.41	0.02
Weighted Average Number of Shares Outstanding (000's)	201,117	197,618	200,002	194,753
Selected Financial Results per BOE(1)				
Oil & Gas Sales(2)	$ 53.61	$ 43.30	$ 49.67	$ 44.10
Royalties	(11.91)	(8.61)	(10.46)	(8.74)
Commodity Derivative Instruments	(1.30)	1.06	0.42	0.11
Operating Costs	(10.58)	(12.32)	(10.52)	(11.00)
General and Administrative	(2.48)	(2.48)	(2.63)	(2.70)
Equity Based Compensation	(0.60)	(0.69)	(0.58)	(0.24)
Interest and Other Expenses	(1.78)	(2.56)	(1.78)	(1.40)
Taxes	(0.65)	0.29	(0.33)	(0.10)
Funds Flow	**$ 24.31**	**$ 17.99**	**$ 23.79**	**$ 20.03**

SELECTED OPERATING RESULTS	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Average Daily Production				
Crude oil (bbls/day)	38,883	36,810	38,426	35,807
NGLs (bbls/day)	2,985	3,538	3,357	3,644
Natural gas (Mcf/day)	275,164	247,347	279,212	249,046
Total (BOE/day)	87,729	81,573	88,318	80,959
% Crude Oil & Natural Gas Liquids	48%	49%	47%	49%
Average Selling Price(2)				
Crude oil (per bbl)	$ 96.30	$ 76.41	$ 86.05	$ 78.72
NGLs (per bbl)	49.88	47.81	51.48	54.88
Natural gas (per Mcf)	2.96	2.20	3.26	2.18
Net Wells drilled	15	17	50	70

(1) Non-cash amounts have been excluded.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Average Benchmark Pricing				
WTI crude oil (US$/bbl)	$ 105.82	$ 92.22	$ 98.14	$ 96.21
AECO – monthly index (CDN$/Mcf)	2.82	2.19	3.16	2.18
AECO – daily index (CDN$/Mcf)	2.43	2.29	3.05	2.11
NYMEX – monthly NX3 index (US$/Mcf)	3.60	2.81	3.68	2.62
USD/CDN exchange rate	1.04	1.00	1.02	1.00

Share Trading Summary **For the three months ended September 30, 2013**	**CDN* – ERF** (CDN$)	**U.S.** – ERF** (US$)
High	$ 18.35	$ 17.69
Low	$ 15.29	$ 14.43
Close	$ 17.05	$ 16.59

* 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
July	$ 0.09	$ 0.09
August	$ 0.09	$ 0.08
September	$ 0.09	$ 0.09
Third Quarter Total	$ 0.27	$ 0.26
Total Year-to-Date	$ 0.81	$ 0.79

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

President's Message

As a result of strong operational performance from our core areas in both Canada and the U.S., I'm pleased to report that we continue to deliver profitable growth within a disciplined capital spending program. Daily production during the third quarter averaged just under 88,000 BOE/day, up 8% from the same period last year. Production from our North Dakota assets continues to outperform our expectations and increased by almost 20% during the quarter to a new record level of 18,000 BOE/day, achieving our 2013 exit forecast for these properties one full quarter ahead of expectations. Year-to-date, production has averaged 88,318 BOE/day, up 9% from the same period a year ago in spite of divestments earlier in the year, and ahead of our guidance.

We allocated the majority of our $146 million capital program during the quarter to our U.S. oil and Canadian waterflood oil assets, where 70% of our drilling program took place. We are seeing improved cost performance in a number of our key operating areas, most notably in Fort Berthold and in the Marcellus. Our capital spending program remains on track with our original guidance for 2013 with a focus on maximizing crude oil and liquids production. Year-to-date, we have spent only two thirds of our annual capital budget yet are exceeding our forecasts for both annual average and exit production, despite the sale of 1,300 BOE/day of non-core production.

This improvement in capital efficiencies, combined with stronger commodity prices, has markedly improved the sustainability of our business in 2013. We generated funds flow of $196 million ($0.98 per share) in the third quarter, up 45% from the third quarter of 2012. Our adjusted payout ratio during the quarter fell to 97% and year-to-date is 103%, a significant improvement from the same periods in 2012.Operating and general and administrative expenses per BOE are also on track and we are maintaining our guidance on both metrics for the full year.

Our financial flexibility has also continued to improve in part from the growth in funds flow and also by our non-core asset sales. The trailing twelve month debt-to-funds flow ratio fell to 1.2 times at the end of September, compared to 1.9 times for the same period last year. On October 22, 2013, we announced an additional sale of non-core assets for approximately $105 million before closing adjustments which further focuses our operations, strengthens our balance sheet and improves our financial position.

With more than 80% of our corporate netback derived from crude oil, we continue to hedge our exposure to crude oil prices to help protect our funds flow and ensure our on-going financial strength. About 74% of our forecast crude oil production, net of royalties, is hedged at just over US$100/bbl for the remainder of 2013. For the first half of 2014, we have price protection on 66% of our crude oil production, net of royalties, at an average price of US$93.70/bbl, while 49% of our forecast crude oil production net of royalties for the second half of 2014 is hedged at US$92.73/bbl. We have 25% of our forecast 2014 natural gas production, net of royalties, hedged at a price of $4.15/Mcf before considering the acquisition of additional interests in the Marcellus.

Production and Capital Spending

	Three months ended September 30, 2013			Nine months ended September 30, 2013		
	Average Production Volumes	Capital Spending ($ millions)		Average Production Volumes	Capital Spending ($ millions)	
Crude Oil & NGLs (BOE/day)						
Canada	19,511	$	35	21,035	$	117
United States	22,357		66	20,748		221
Total Crude Oil & NGLs (BOE/day)	41,868	$	101	41,783	$	338
Natural Gas (Mcf/day)						
Canada	174,169	$	22	179,503	$	67
United States	100,995		23	99,709		53
Total Natural Gas (Mcf/day)	275,164	$	45	279,212	$	120
Company Total (BOE/day)	87,729	$	146	88,318	$	458

Net Drilling Activity – for the three months ended September 30, 2013

	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-in*	Wells On-stream**	Dry & Abandoned Wells
Crude Oil						
Canada	4.7	–	4.7	2.7	5.7	–
United States	6.6	–	6.6	5.3	3.2	–
Total Crude Oil	**11.3**	**–**	**11.3**	**8.0**	**8.9**	**–**
Natural Gas						
Canada	1.1	–	1.1	1.1	–	–
United States	2.8	–	2.8	2.6	2.2	–
Total Natural Gas	**3.9**	**–**	**3.9**	**3.7**	**2.2**	**–**
Company Total	**15.2**	**–**	**15.2**	**11.7**	**11.1**	**–**

* Wells drilled during the quarter that are pending potential completion/tie-in or abandonment as at September 30, 2013.

** Total wells brought on-stream during the quarter regardless of when they were drilled.

U.S. Crude Oil

We continued to allocate the majority of our capital spending to the Williston Basin, targeting light crude oil from the Bakken and Three Forks oil plays. During the quarter we invested $66 million at Fort Berthold, North Dakota, drilling 6.6 net horizontal wells and bringing 3.2 net horizontal wells on stream. During this period our North Dakota production grew by almost 2,900 BOE/day to a record 18,000 BOE/day, a 19% increase from the last quarter. Combined with our Bakken production from Montana, our U.S. assets now account for more than half of Enerplus' total crude oil and liquids volumes.

We are also seeing a significant improvement in well performance as we continue to optimize our completion design. Since the start of 2013, we have evolved our completions, moving from ceramic proppant to white sand proppant while increasing the number of frac stages by 40% and the amount of proppant per stage by over 200%. Despite the increase in frac size, our average cost per frac stage has decreased by approximately 15%. More significantly, the average 30 day cumulative initial production in our most recent Bakken and Three Forks wells is 80% or higher than the rates we were achieving at the start of 2013.

We've drilled 10.6 net wells in the Bakken and 4.9 net wells in the first bench of the Three Forks to date in 2013 and continue to explore downspacing and testing of the lower benches of the Three Forks in order to expand our drilling inventory.

Canadian Crude Oil

Production from our Canadian oil assets averaged approximately 19,500 BOE/day, down from second quarter results of 21,300 BOE/day largely due to downtime at our Medicine Hat "Glauc C" property and the sale of non-core production earlier in the year.

In Saskatchewan, results on the Ratcliffe trend continued to exceed our expectations. These assets attracted the highest share of investment amongst our waterflood properties during the quarter as we drilled 3.7 net horizontal wells in the area, brought 2 net wells on stream, and continued to invest in infrastructure to support our growing production in the region. Initial production volumes over the first 30 days from these wells are exceeding our type curve expectations by almost 60%, with rates of about 220 bbls/day. We plan on drilling 2 additional gross (1.3 net) wells offsetting these producers during the fourth quarter of 2013.

U.S. Natural Gas

Production from the Marcellus averaged 83 MMcf/day of natural gas during the quarter, ahead of our planned 2013 exit rate of 75 MMcf/day. We continue to be encouraged by strong well performance and as new wells come on stream, we expect to reach record production levels in the fourth quarter. We invested $23 million in the Marcellus during the quarter, which included the drilling of 2.8 net wells and bringing 2.2 net wells on stream. As a result of the production growth achieved year-to-date and an improvement in NYMEX natural gas prices year-over-year, funds flow has increased significantly from the Marcellus with approximately $48 million realized year-to-date. Additionally, well costs have also improved, declining approximately 20% from our original budget expectations. Given the on-going production growth from the Marcellus and lagging infrastructure expansion, differentials in the region continued to widen. Our long-term sales contracts on over 75% of our current production provided us with a degree of protection, resulting in our average realized Marcellus gas price being about US$0.52/Mcf below the NYMEX price during the quarter. Until infrastructure catches up to the burgeoning natural gas supply and new markets open up, we expect that wide differentials will persist in the region.

Canadian Natural Gas

Our Canadian natural gas activities continued to be focused in the Deep Basin region of Alberta where we are advancing our development plans in the Wilrich and continuing to delineate the Duvernay.

Based upon the success of our drilling activity in the Wilrich, we acquired an additional 5,000 net acres in the Minehead area during the third quarter and have moved one dedicated rig to the region to execute our development plans. We plan to drill and complete one well in the fourth quarter and expect to spud a second well which will be completed in early 2014.

As a result of recent drilling activity, Enerplus now has core data from three Duvernay vertical delineation test wells on varying sections of our leases in the Willesden Green area. The core analysis from these wells is positive and in our view supports a range of expected free condensate of 75 – 150 bbls per million cubic feet of natural gas over a significant portion of our acreage block. This data supports our current plan to drill a horizontal re-entry which is underway in one of the vertical tests. We expect to follow with another horizontal well with completion of both wells scheduled in 2014.

Marcellus Acquisition and Montney Disposition Subsequent to the Quarter

Consistent with our strategy to concentrate our portfolio in top tier assets in core areas, we have entered into agreements to add to our U.S. gas position in the Marcellus and to also sell our Montney interests in northeastern British Columbia.

We have entered into an agreement to acquire additional working interests in 17,000 net non-operated acres within our core properties in the Marcellus with current production of approximately 42 MMcf/day of natural gas for US$153 million before closing adjustments.

The acquisition increases our working interest in existing non-operated leases within the northeast region of Pennsylvania. Since entering the play in 2009, well performance from this region has surpassed our expectations and increased our confidence in the productivity and economic viability of the Marcellus. Based upon the drilling results achieved to date, we expect ultimate recoveries of natural gas in the best areas to range from 10 Bcf to 13.5 Bcf or higher per well. Close to half of the acquired leases are located in 10 Bcf or greater areas and virtually all of the value of the transaction has been attributed to these Tier 1 areas with approximately 44 net future drilling locations.

Approximately 60% of the total leases being acquired are currently held by production. With the majority of our existing core leasehold acreage now held by production, we have seen an improvement in drilling efficiencies to date in 2013 that has resulted in lower well costs. Based upon our expected ultimate recoveries and current well costs of under $7 million, we expect top tier full cycle finding, development and acquisition costs of less than $1.00 per Mcf with attractive recycle ratios.

Upon closing of the acquisition, Enerplus' core Marcellus acreage will total approximately 60,000 net acres. We plan to more fully outline our capital spending plans when we release our 2014 production and capital forecast in December of this year. The acquisition is expected to close at the end of November 2013 and as a result will increase our 2013 exit rate guidance from 88,000 BOE/day to 95,000 BOE/day. This increase in natural gas production in 2014 is expected to provide us with the opportunity to continue selling non-core assets and high-grading our portfolio. Our 2013 annual average production and capital spending forecast is not expected to change materially as a result of the acquisition.

We have also entered into an agreement to sell our Montney interests at Julienne Creek for $130 million. While we believe the Julienne Creek asset offers significant scope and scale, the natural gas produced in this area is predominantly dry with very little associated natural gas liquids production. Our core assets in the Williston Basin, our waterfloods, the Marcellus and the Deep Basin (Wilrich and Duvernay) provide us with a deep inventory of future drilling prospects that offer more favourable economics and will enable us to grow production, reserves and cash flow in existing areas in both the near and long-term. Enerplus has invested approximately $50 million building our position in the Montney. The sale includes 33,300 net contiguous acres (100% working interest) with no current production or reserves, representing sale metrics of approximately $3,900 per acre.

Summary

Our quarterly results once again reflect the benefits of our multi-year strategy to position Enerplus in top tier resource plays and develop them within a disciplined capital allocation and cost management framework. Our non-core property dispositions continue to help us improve our financial flexibility and enable us to focus our expertise and capital spending within our four core areas. These strategies are driving improved capital efficiencies and achieving sustainable, profitable growth and income for our investors. We plan to continue on this path of value creation for our shareholders.

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation

Management's Discussion and Analysis

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

The following discussion and analysis of financial results is dated November 7, 2013 and is to be read in conjunction with:

- the unaudited interim consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three and nine months ended September 30, 2013 and 2012 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at and for the years ended December 31, 2012 and 2011 (the "Financial Statements"); and
- the MD&A of Enerplus for the year ended December 31, 2012 (the "Annual MD&A").

All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Interim Financial Statements. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. 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. 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 discussion at the end of the MD&A under "Forward-Looking Information and Statements" for further information.

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 International Financial Reporting Standards ("IFRS") and therefore may not be comparable with the calculation of similar measures by other entities:

"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 dividends and the Company's former Dividend Reinvestment Plan ("DRIP") proceeds, plus capital spending (including office capital) divided by funds flow.

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

OVERVIEW

During the third quarter we continued to deliver strong production levels averaging 87,729 BOE/day. As we expected, production decreased 3% from the second quarter of 2013 due to planned turnaround activity, reduced capital spending earlier in the year, and the impact of non-core asset dispositions. With strong performance from our core Canadian properties and higher than anticipated production from our Fort Berthold and Marcellus properties, we have increased our annual average production guidance to 87,500 BOE/day from 85,000 BOE/day. Our development capital program remains on track with spending of $145.8 million during the quarter, primarily focused on our Fort Berthold and Canadian crude oil properties. Operating expenses of $10.60/BOE and general and administrative expenses ("G&A") of $2.48/BOE were in line with expectations during the quarter.

Third quarter funds flow totaled $196.2 million, an increase of 45% from the same period in 2012. As expected, lower production during the quarter resulted in funds flow decreasing by 4% compared to the second quarter of 2013. Net income for the quarter totaled $34.0 million, up from a $63.5 million net loss in the same period of 2012 due to higher production volumes and improved realized pricing as well as no impairment charges recorded against our assets.

We have continued to focus our asset portfolio and improve our financial flexibility through our acquisition and disposition activity. In the third quarter, we realized proceeds of $124.5 million on our disposition activities. Subsequent to the quarter we signed agreements for additional dispositions including non-core Canadian oil assets for proceeds of approximately $105 million before closing adjustments, along with our undeveloped Montney acreage for proceeds of approximately $130 million. We also entered into an agreement to acquire additional working interests in our existing non-operated Marcellus leases in northeast Pennsylvania for approximately US$153 million before closing adjustments. The Marcellus acquisition is expected to close at the end of November 2013 and will increase our 2013 exit rate guidance to 95,000 BOE/day from 88,000 BOE/day. Our 2013 annual average production and capital spending forecast is not expected to change materially as a result of the acquisition.

Our adjusted payout ratio continued to improve at 97% for the third quarter and 103% year-to-date, due to strong production and funds flow growth as well as improving capital efficiencies. At September 30, 2013, we had a conservative trailing twelve month debt to funds flow ratio of 1.2x and approximately $815.0 million of available capacity on our bank credit facility.

RESULTS OF OPERATIONS

Production

Production decreased to 87,729 BOE/day in the third quarter of 2013 from 90,037 BOE/day in the second quarter, which was expected given planned turnaround activity, reduced capital spending earlier in 2013, and the disposition of approximately 1,300 BOE/day (net of acquisitions) throughout the first nine months of the year. Compared to the same periods in 2012, production increased 8% during the quarter and 9% year-to-date mainly due to increased production from our Fort Berthold and Marcellus assets.

Our weighting of crude oil and liquids production was 48% during the third quarter. We continue to expect our crude oil and liquids weighting to average 48% for 2013.

Average daily production volumes for the three and nine months ended September 30, 2013 and 2012 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2013**	**2012**	**% Change**	**2013**	**2012**	**% Change**
Crude oil (bbls/day)	38,883	36,810	6%	38,426	35,807	7%
Natural gas liquids (bbls/day)	2,985	3,538	(16)%	3,357	3,644	(8)%
Natural gas (Mcf/day)	275,164	247,347	11%	279,212	249,046	12%
Total daily sales (BOE/day)	87,729	81,573	8%	88,318	80,959	9%

Based on our strong production performance we have increased our annual average production guidance to 87,500 BOE/day from 85,000 BOE/day, despite the sale of 2,200 BOE/day. We have also increased our exit rate guidance to 95,000 BOE/day from 88,000 BOE/day to reflect the acquisition of additional working interests in the Marcellus that are expected to close at the end of November.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, funds flow and financial condition. The following table compares quarterly average prices from the third quarter of 2012 to the third quarter of 2013.

	Nine months ended September 30						
Pricing (average for the period)	**2013**	**2012**	**Q3 2013**	**Q2 2013**	**Q1 2013**	**Q4 2012**	**Q3 2012**
Benchmarks							
WTI crude oil (US$/bbl)	$ 98.14	$ 96.21	$ 105.82	$ 94.22	$ 94.37	$ 88.18	$ 92.22
AECO – monthly index (CDN$/Mcf)	3.16	2.18	2.82	3.59	3.08	3.06	2.19
AECO – daily index (CDN$/Mcf)	3.05	2.11	2.43	3.53	3.20	3.22	2.29
NYMEX – monthly NX3 (US$/Mcf)	3.68	2.62	3.60	4.09	3.35	3.36	2.81
US/CDN exchange rate	1.02	1.00	1.04	1.02	1.01	0.99	1.00
Enerplus selling price (1)							
Crude oil (per bbl)	$ 86.05	$ 78.72	$ 96.30	$ 82.95	$ 78.52	$ 76.75	$ 76.41
Natural gas liquids (per bbl)	51.48	54.88	49.88	45.64	58.58	47.31	47.81
Natural gas (per Mcf)	3.26	2.18	2.96	3.70	3.10	3.01	2.20
Average differentials (US$/bbl or US$/Mcf)							
MSW Edmonton – WTI	$ (5.11)	$ (9.27)	$ (4.72)	$ (3.67)	$ (6.95)	$ (3.32)	$ (7.21)
WCS Hardisty – WTI	(22.86)	(22.00)	(17.48)	(19.16)	(31.96)	(18.11)	(21.72)
Brent Futures (ICE) – WTI	10.40	16.00	3.83	9.14	18.24	21.81	17.22
AECO monthly – NYMEX	(0.62)	(0.41)	(1.00)	(0.58)	(0.28)	(0.31)	(0.60)
Enerplus realized differentials (1)							
U.S. crude oil – WTI	$ (8.84)	$ (14.29)	$ (11.41)	$ (9.61)	$ (6.10)	$ (5.18)	$ (12.90)
Canada crude oil – WTI	(19.96)	(20.08)	(15.18)	(16.97)	(26.97)	(15.54)	(17.41)
U.S. natural gas – NYMEX	0.02	0.36	(0.18)	0.08	0.12	0.34	0.34
Canada natural gas – NYMEX	(0.77)	(0.64)	(1.08)	(0.78)	(0.49)	(0.57)	(0.86)

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

Crude Oil and Natural Gas Liquids

WTI crude oil prices averaged US$105.82 during the third quarter. Geopolitical tensions in the Middle East combined with a significant draw in light sweet oil inventories in the U.S. as refineries returned from planned and unplanned shutdowns, pushed WTI prices to a high of over US$110/bbl before falling back to approximately US$102/bbl at the end of September. This resulted in dramatically increased backwardation along the forward curve.

Differentials for Canadian crude oil remained relatively tight for July and August as maintenance in the oil sands and delays in new heavy oil production provided significant price support. However, heavy differentials widened as increased Canadian heavy oil production was met with a seasonal decline in refinery demand and lower runs, resulting in a much weaker demand for heavy oil in the market late in the quarter. Differentials in the U.S. widened slightly in the third quarter to US$11.41/bbl below WTI as production in the region continued to increase at a rapid pace and as Gulf Coast refiners continued to deal with a rising influx of light sweet crude oil.

Natural gas liquids ("NGL") prices increased compared to the previous quarter, in line with the strength in WTI prices. However year over year, our realized NGL pricing has decreased as a result of higher fractionation and transportation costs due to capacity constraints in the local Alberta market. We expect realized NGL prices to remain weak through the balance of the year and into 2014 until new fractionation capacity is built in the province.

The average price received for our crude oil production (net of transportation costs) in the third quarter of 2013 increased 16% to $96.30/bbl compared to the second quarter and was up 26% from the same period in 2012. The improvement in our pricing is due to increasing WTI prices along with a higher proportion of our production being light crude oil from our Fort Berthold properties. Our realized differentials relative to WTI remained relatively flat, as the impact of widening U.S. differentials was offset by narrowing Canadian differentials.

Natural Gas

Natural gas prices weakened during the third quarter as below normal temperatures across key regions in North America failed to generate cooling demand during the summer. In addition, increasing U.S. gas production and the displacement of gas-fired power generation due to low coal prices put further downward pressure on the natural gas market.

In Canada, prices at AECO fell relative to NYMEX as the market adjusted to a new tolling mechanism mandated by the National Energy Board on the TransCanada mainline. TransCanada is now allowed to use its discretion in setting short-term firm service and interruptible rates on this pipeline. These rates were set at two to three times the cost of long-term firm service, resulting in a significant widening of the basis differential between AECO and Henry Hub. In addition, various short-term pipeline outages due to the floods in June, along with high western Canadian storage levels, led to further weakness in Canadian gas prices in September.

In the U.S., spot prices on Tennessee Gas Pipeline ("TGP") and Transco in the northeast weakened significantly through the quarter with increasing Marcellus production and capacity constraints due to maintenance on these pipelines. We have long-term sales contracts in place that are based on both monthly and daily regional index prices that provide some protection from the much weaker TGP and Transco spot markets. Because of these agreements, our average Marcellus price was approximately US$0.52/Mcf below NYMEX prices during the quarter, compared to benchmark daily spot discounts on the Tennessee Gas Pipeline 300 line and Transco Leidy line ranging between US$1.16/Mcf and US$2.11/Mcf below NYMEX. We expect that wider differentials will continue in the region until pipeline expansions are built to manage excess gas from the producing areas. Accessing new and incremental markets will be necessary to consume the growing gas production in the Marcellus region.

For the three months ended September 30, 2013 we sold our natural gas for an average price of $2.96/Mcf (net of transportation costs) which represented a 20% decrease from an average price of $3.70/Mcf received during the second quarter of 2013 and a 35% increase compared to the same period in 2012. Of our total gas production during the current quarter, 63% was from Canada with an average price of $2.62/Mcf and 37% was from the U.S. at $3.55/Mcf, net of transportation. In the third quarter of 2012 our Canadian production was 78% of our total gas production. Our realized prices were in-line with the widening of the AECO and NYMEX differentials during this period along with the widening differential experienced in the Marcellus region.

Price Risk Management

We have a price risk management program that is designed to mitigate a portion of the variability in commodity prices. The program considers our overall financial position along with the economics of our capital program and potential acquisitions. Our crude oil production accounted for approximately 81% of our corporate netback for the nine months ended September 30, 2013 and therefore we believe it is prudent to have a significant level of downside price protection. As of October 22, 2013 we have swapped 22,500 bbls/day for the remainder of 2013 at an average price of US$100.36/bbl, representing approximately 74% of our forecasted net crude oil production after royalties. For the first half of 2014, we have swapped 20,000 bbls/day, representing approximately 66% of our forecasted net crude oil production after royalties, at an average price of US$93.70/bbl. For the second half of 2014 we have swapped 15,000 bbls/day, representing approximately 49% of our forecasted net crude oil production after royalties, at an average price of US$92.73/bbl. In addition we have swapped 500 bbl/day at US$90.00/bbl for 2015, representing approximately 2% of our net crude oil production after royalties.

In order to diversify away some of our crude oil price exposure from North America, we have also added Brent – WTI fixed and ratio spread basis positions. We have entered into fixed basis spread positions for the remainder of 2013 where we pay the WTI calendar month average price and receive the Brent calendar month average price less a fixed spread of US$7.09/bbl on 5,000 bbls/day. For 2014 we have entered into ratio spread basis positions where we pay the WTI calendar month average price and receive 93.1% of the Brent calendar month average price on 3,000 bbls/day.

For the remainder of 2013 and 2014, we have also entered into Western Canadian Select ("WCS") and Edmonton Light Sweet ("MSW") differential swap positions. WCS differentials have been fixed at WTI less US$21.56/bbl for the remainder of 2013 on 2,000 bbls/day and WTI less US$23.25/bbl for 2014 on 1,000 bbls/day. MSW differentials have been fixed at WTI less US$5.90/bbl for the remainder of 2013 on 500 bbls/day.

As of October 22, 2013 we had downside protection representing approximately 31% of our forecasted natural gas production after royalties for the remainder of 2013. This protection is comprised of 51,100 Mcf/day at AECO $3.41/Mcf before premiums and 15,000 Mcf/day swapped at NYMEX US$3.85/Mcf. For 2014 we have swapped 50,000 Mcf/day at NYMEX US$4.17/Mcf and another 4,700 Mcf/day at AECO $3.96/Mcf, representing approximately 25% of our forecasted net natural gas production after royalties.

The following is a summary of our financial contracts in place at October 22, 2013 expressed as a percentage of our anticipated net production volumes after royalties:

	WTI Crude Oil(1) (US$/bbl)			AECO Natural Gas(1) (CDN$/Mcf)		NYMEX Natural Gas(1) (US$/Mcf)	
	Oct 1, 2013 – Dec 31, 2013	Jan 1, 2014 – Jun 30, 2014	Jul 1, 2014 – Dec 31, 2014	Oct 1, 2013 – Dec 31, 2013	Jan 1, 2014 – Dec 31, 2014	Oct 1, 2013 – Dec 31, 2013	Jan 1, 2014 – Dec 31, 2014
Purchased Puts	–	–	–	$ 3.17	–	–	–
%	–	–	–	11%	–	–	–
Sold Puts	$ 63.09	–	–	–	–	–	–
%	18%	–	–	–	–	–	–
Swaps (fixed price)	$ 100.36	$ 93.70	$ 92.73	$ 3.61	$ 3.96	$ 3.85	$ 4.17
%	74%	66%	49%	13%	2%	7%	23%
Sold Calls	$ 130.00	–	–	–	–	–	–
%	11%	–	–	–	–	–	–
Purchased Calls	$ 104.09	–	–	–	–	–	–
%	11%	–	–	–	–	–	–

(1) Based on weighted average price (before premiums), assumed average annual production of 87,500 BOE/day for 2013 and 2014, less royalties of 21%.

For 2015 we have swapped 500 bbls/day of crude oil at US$90.00/bbl, representing approximately 2% of our forecasted net production after royalties. See Note 15 for further information on our commodity hedging.

Accounting for Price Risk Management

During the third quarter of 2013 we realized cash losses of $12.9 million on our crude oil contracts and cash gains of $2.3 million on our natural gas contracts. In comparison, during the third quarter of 2012 we realized cash gains of $7.9 million on our crude oil contracts. The crude oil losses realized in the current quarter are due to market prices rising above our fixed price positions. The natural gas gain realized during the current quarter and the crude oil gain recognized in the same period in 2012 were due to contracts that 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 the end of the third quarter of 2013 the fair value of our crude oil contracts represented a loss position of $15.8 million, while our natural gas contracts represented a gain position of $7.6 million. For the three and nine months ended September 30, 2013 the fair value of our crude oil contracts decreased $45.6 million and $66.5 million respectively, while the fair value of our natural gas contracts increased $0.5 million and $4.3 million respectively.

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	Three months ended September 30, 2013		2012	
Cash gains/(losses):				
Crude Oil	$ (12.9)	$ (3.59)/bbl	$ 7.9	$ 2.34/bbl
Natural Gas	2.3	$ 0.09/Mcf	–	$ – /Mcf
Total cash gains/(losses)	$ (10.6)	$ (1.30)/BOE	$ 7.9	$ 1.06/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – crude oil	$ (45.6)	$ (12.75)/bbl	$ (47.3)	$ (13.98)/bbl
Change in fair value – natural gas	0.5	$ 0.02/Mcf	(1.4)	$ 0.06)/Mcf
Total non-cash gains/(losses)	$ (45.1)	$ (5.60)/BOE	$ (48.7)	$ (6.49)/BOE
Total gains/(losses)	**$ (55.7)**	**$ (6.90)/BOE**	**$ (40.8)**	**$ (5.43)/BOE**

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	Nine months ended September 30, 2013		2012	
Cash gains/(losses):				
Crude Oil	$ 9.0	$ 0.86/bbl	$ 2.3	$ 0.23/bbl
Natural Gas	1.1	$ 0.01/Mcf	–	$ – /Mcf
Total cash gains/(losses)	$ 10.1	$ 0.42/BOE	$ 2.3	$ 0.11/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – crude oil	$ (66.5)	$ (6.34)/bbl	$ 73.3	$ 7.47/bbl
Change in fair value – natural gas	4.3	$ 0.06/Mcf	(1.4)	$ (0.02)/Mcf
Total non-cash gains/(losses)	$ (62.2)	$ (2.58)/BOE	$ 71.9	$ 3.24/BOE
Total gains/(losses)	**$ (52.1)**	**$ (2.16)/BOE**	**$ 74.2**	**$ 3.35/BOE**

Revenues

Crude oil and natural gas revenues were $432.7 million ($441.5 million, net of $8.8 million of transportation costs) in the third quarter of 2013, representing an increase of $107.8 million or 33% from $324.9 million ($331.7 million, net of $6.8 million of transportation costs) during the same period in 2012. Crude oil and natural gas revenues for the nine months ended September 30, 2013 were $1,197.5 million ($1,219.8 million, net of $22.3 million of transportation costs), an increase of $219.2 million or 22% from $978.3 million ($998.1 million, net of $19.8 million in transportation costs) for the same period in 2012. Crude oil and natural gas revenues increased due to higher realized prices and higher production levels during both periods.

Analysis of Sales Revenue(1) ($ millions)	Crude Oil	NGLs	Natural Gas	Total
Three months ended September 30, 2012	$ 258.7	$ 15.6	$ 50.6	$ 324.9
Price variance	71.2	0.4	18.5	90.1
Volume variance	14.6	(2.3)	5.4	17.7
Three months ended September 30, 2013	**$ 344.5**	**$ 13.7**	**$ 74.5**	**$ 432.7**

($ millions)	Crude Oil	NGLs	Natural Gas	Total
Nine months ended September 30, 2012	$ 772.3	$ 54.8	$ 151.2	$ 978.3
Price variance	76.9	(3.1)	79.6	153.4
Volume variance	53.5	(4.5)	16.8	65.8
Nine months ended September 30, 2013	**$ 902.7**	**$ 47.2**	**$ 247.6**	**$ 1,197.5**

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

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. For the three and nine months ended September 30, 2013 royalties were $96.1 million and $252.1 million respectively, compared to $64.6 million and $193.8 million for the same periods of 2012. As a percentage of oil and gas sales, net of transportation costs, royalties were 22% and 21% for the three and nine months ended September 30, 2013 respectively, compared to 20% for the same periods in 2012. The increase in our royalty rate is due to higher crude oil and natural gas prices compared to the prior year as well as an increased proportion of U.S. production where royalty rates are higher than those on our Canadian production. We continue to expect an average royalty rate of approximately 21% in 2013.

Operating Expenses

Operating expenses were in line with expectations at $85.5 million or $10.60/BOE during the third quarter of 2013 and $252.3 million or $10.46/BOE for the nine months ended September 30, 2013. In comparison, operating expenses for the three and nine months ended September 30, 2012 were $94.5 million or $12.59/BOE and $247.1 million or $11.14/BOE respectively.

Operating costs in the third quarter of 2013 were lower than the same period in 2012 due to increased production from our U.S. properties with lower operating costs, the disposition of higher operating cost non-core properties, and non-routine expenses incurred in the same period in 2012. For the first nine months of 2013 our spending is marginally higher than the prior year with increased well servicing and repairs and maintenance work, along with increased fluid handling and gas facility charges as a result of our increased production.

We are maintaining our annual guidance of $10.70/BOE for operating costs during 2013.

Netbacks

The following tables outline our crude oil and natural gas netbacks for the three and nine months ended September 30, 2013 and 2012. The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section of this MD&A.

	Three months ended September 30, 2013					
Netbacks by Property Type		**Crude Oil**		**Natural Gas**		**Total**
Average Daily Production		43,443 BOE/day		265,714 Mcfe/day		87,729 BOE/day
Netback[1] $ per BOE or Mcfe		(per BOE)		(per Mcfe)		(per BOE)
Revenue[2]	$	87.58	$	3.38	$	53.61
Royalties		(20.66)		(0.55)		(11.91)
Cash operating costs		(12.08)		(1.52)		(10.58)
Netback before hedging	$	54.84	$	1.31	$	31.12
Cash gains/(losses)		(3.22)		0.10		(1.30)
Netback after hedging	$	51.62	$	1.41	$	29.82
Netback before hedging ($ millions)	$	219.2	$	32.0	$	251.2
Netback after hedging ($ millions)	**$**	**206.3**	**$**	**34.3**	**$**	**240.6**

	Three months ended September 30, 2012					
Netbacks by Property Type		**Crude Oil**		**Natural Gas**		**Total**
Average Daily Production		40,561 BOE/day		246,069 Mcfe/day		81,573 BOE/day
Netback[1] $ per BOE or Mcfe		(per BOE)		(per Mcfe)		(per BOE)
Revenue[2]	$	70.22	$	2.78	$	43.30
Royalties		(15.72)		(0.26)		(8.61)
Cash operating costs		(13.78)		(1.81)		(12.32)
Netback before hedging	$	40.72	$	0.71	$	22.37
Cash gains/(losses)		2.12		–		1.06
Netback after hedging	$	42.84	$	0.71	$	23.43
Netback before hedging ($ millions)	$	152.0	$	15.8	$	167.8
Netback after hedging ($ millions)	**$**	**159.9**	**$**	**15.8**	**$**	**175.7**

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

Netbacks by Property Type	Nine months ended September 30, 2013 Crude Oil	Natural Gas	Total
Average daily production	42,471 BOE/day	275,084 Mcfe/day	88,318 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue[(2)]	$ 78.97	$ 3.75	$ 49.67
Royalties	(18.62)	(0.48)	(10.46)
Cash operating costs	(12.24)	(1.49)	(10.52)
Netback before hedging	$ 48.11	$ 1.78	$ 28.69
Cash gains/(losses)	0.78	0.01	0.42
Netback after hedging	$ 48.89	$ 1.79	$ 29.11
Netback before hedging ($ millions)	$ 557.8	$ 134.0	$ 691.8
Netback after hedging ($ millions)	**$ 566.8**	**$ 135.1**	**$ 701.9**

Netbacks by Property Type	Nine months ended September 30, 2012 Crude Oil	Natural Gas	Total
Average daily production	39,026 BOE/day	251,600 Mcfe/day	80,959 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue[(2)]	$ 72.31	$ 2.98	$ 44.10
Royalties	(15.84)	(0.35)	(8.74)
Cash operating costs	(12.28)	(1.63)	(11.00)
Netback before hedging	$ 44.19	$ 1.00	$ 24.36
Cash gains/(losses)	0.22	–	0.11
Netback after hedging	$ 44.41	$ 1.00	$ 24.47
Netback before hedging ($ millions)	$ 472.5	$ 68.1	$ 540.6
Netback after hedging ($ millions)	**$ 474.8**	**$ 68.1**	**$ 542.9**

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

Our crude oil properties accounted for 81% of our corporate netback before hedging for the first nine months of 2013 compared to 87% for the same period in 2012. Crude oil netbacks per BOE and natural gas netbacks per Mcfe, both after hedging, have increased for the three and nine months ended September 30, 2013 primarily due to higher realized crude oil and natural gas prices.

General and Administrative ("G&A") Expenses

G&A expenses for the three and nine months ended September 30, 2013 were $20.0 million or $2.48/BOE and $63.5 million or $2.63/BOE respectively, compared to $18.6 million or $2.48/BOE and $59.9 million or $2.70/BOE for the same periods during 2012. The increased spending during 2013 was primarily related to compensation costs and one-time charges recorded in the first quarter.

Cash G&A Expenses	Three months ended September 30, 2013	2012	Nine months ended September 30, 2013	2012
G&A expenses ($ millions)	$ 20.0	$ 18.6	$ 63.5	$ 59.9
G&A expenses (per BOE)	$ 2.48	$ 2.48	$ 2.63	$ 2.70

We continue to expect cash G&A expenses to be approximately $2.70/BOE during 2013.

Equity Based Compensation Expenses

Equity based compensation expenses totaled $5.1 million for the third quarter of 2013 and $17.5 million for the nine months ended September 30, 2013, compared to $5.1 million and $10.0 million for the same periods during 2012. These expenses include charges related to our long-term incentive plans ("LTI plans") and our stock option plan (see Note 14 for further details). The costs of our LTI plans are dependent on our share price and can fluctuate from period to period. The increased costs in 2013 are the result of the increase in our share price during the year.

We also recorded non-cash gains on our LTI equity swaps of $1.5 million for the third quarter and $3.8 million for the nine months ended September 30, 2013, compared to $2.7 million and $3.1 million of non-cash gains during the same periods in 2012. Utilizing the swaps, we have effectively fixed the future settlement cost on our LTI plans at a weighted average price of $13.21 per share on 1,130,000 shares, representing approximately 69% of the notional shares outstanding under these plans.

	Three months ended September 30,		Nine months ended September 30,	
Equity Based Compensation Expenses ($ millions)	2013	2012	2013	2012
Cash:				
LTI plans expense	$ 4.9	$ 5.2	$ 14.1	$ 5.4
Non-Cash:				
LTI plans – equity swap gain	(1.5)	(2.7)	(3.8)	(3.1)
Stock option plan	1.7	2.6	7.2	7.7
Total equity based compensation expenses	**$ 5.1**	**$ 5.1**	**$ 17.5**	**$ 10.0**

	Three months ended September 30,		Nine months ended September 30,	
Equity Based Compensation Expenses (Per BOE)	2013	2012	2013	2012
Cash:				
LTI plans expense	$ 0.60	$ 0.69	$ 0.58	$ 0.24
Non-Cash:				
LTI plans – equity swap gain	(0.18)	(0.37)	(0.16)	(0.14)
Stock option plan	0.21	0.35	0.30	0.35
Total equity based compensation expenses	**$ 0.63**	**$ 0.67**	**$ 0.72**	**$ 0.45**

We continue to expect cash equity based compensation charges of approximately $0.60/BOE during 2013.

Finance Expense

Interest on our senior notes and bank credit facility for the three and nine months ended September 30, 2013 totaled $14.7 million and $43.1 million respectively, compared to $14.9 million and $39.1 million for the same periods in 2012. The year-to-date increase is due to an increased weighting of senior notes with higher interest rates compared to 2012. The quarter over quarter decrease was due to lower average debt levels in the third quarter of 2013.

Non-cash amounts recorded in finance expense include accretion of decommissioning liabilities, amortization of debt transaction costs and 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.

	Three months ended September 30,		Nine months ended September 30,	
Finance Expense ($ millions)	2013	2012	2013	2012
Interest on senior notes and bank facility	$ 14.7	$ 14.9	$ 43.1	$ 39.1
Non-cash finance expense	3.8	4.0	12.3	13.0
Total finance expense	**$ 18.5**	**$ 18.9**	**$ 55.4**	**$ 52.1**

At September 30, 2013 approximately 76% of our debt was based on fixed interest rates at a weighted average rate of approximately 5.8% and the remaining 24% was based on floating interest rates at a weighted average rate of approximately 2.8%.

Foreign Exchange

For the three and nine months ended September 30, 2013 we recorded a foreign exchange gain of $2.5 million and a foreign exchange loss of $4.0 million respectively, compared to gains of $13.6 million and $18.9 million in the same periods in 2012.

Realized foreign exchange gains were minimal during the quarter and the year-to-date realized loss of $17.7 million is primarily due to the second quarter CCIRS settlement on our US$175 million senior notes. Upon settlement of the swap, we realized a loss of $18.0 million and recognized a corresponding mark-to-market unrealized gain.

We recorded net unrealized foreign exchange gains during the third quarter of $2.6 million, mainly due to mark-to-market gains on our CCIRS and foreign exchange swaps which were partially offset by unrealized losses on the period end translation of our U.S. dollar debt. See Note 12 for further details.

	Three months ended September 30,		Nine months ended September 30,	
Foreign Exchange ($ millions)	2013	2012	2013	2012
Realized loss/(gain)	$ 0.1	$ 4.1	$ 17.7	$ 10.0
Unrealized loss/(gain)	(2.6)	(17.7)	(13.7)	(28.9)
Total foreign exchange loss/(gain)	**$ (2.5)**	**$ (13.6)**	**$ 4.0**	**$ (18.9)**

Capital Investment

Capital spending for the third quarter totaled $145.8 million, up slightly from the second quarter of 2013 and lower than $167.0 million spent during the same period in 2012. Our capital program remains on track with guidance of $685 million as we continue to expect higher spending in the fourth quarter. Third quarter spending continued to focus primarily on our crude oil properties with $66.5 million directed towards our Fort Berthold crude oil property and $35.2 million spent on our Canadian oil properties. Spending on our natural gas assets included $23.3 million in the Marcellus and $16.5 million on our deep basin properties in Canada.

Property and land acquisitions for the third quarter totaled $15.8 million, which included $6.4 million for additional land interests in the Canadian deep basin, $7.5 million in Fort Berthold and $1.9 million in the Marcellus. During the third quarter of 2012 we spent $7.3 million on acquisitions, consisting of $2.7 million on additional lands in Fort Berthold and $4.6 million on our Marcellus carry obligation which fully satisfied our carry commitment.

Subsequent to September 30, 2013 we entered into an agreement to purchase additional non-operated working interests in the Marcellus which included approximately 7,000 BOE/day of current production and 17,000 net acres in northeast Pennsylvania for approximately US$153 million.

Dispositions

Property dispositions during the third quarter totaled $124.5 million. These divestments consisted of non-core Canadian properties primarily in Saskatchewan and Alberta with production of approximately 1,100 BOE/day for proceeds of $89.3 million. We also sold facilities in Fort Berthold for proceeds of $35.2 million. With respect to these dispositions we recognized gains of $30.5 million.

Subsequent to September 30, 2013 we entered into agreements to sell non-core Canadian oil properties with production of 900 BOE/day for proceeds of approximately $105 million as well as our undeveloped Montney acreage for proceeds of approximately $130 million.

Our total capital investment activity for the three and nine months ended September 30, 2013 is outlined below:

	Three months ended September 30,		Nine months ended September 30,	
Capital Investment ($ millions)	2013	2012	2013	2012
Capital spending	$ 145.8	$ 167.0	$ 458.4	$ 692.7
Office capital	1.2	2.7	3.4	8.8
Sub-total	147.0	169.7	461.8	701.5
Property and land acquisitions	15.8	7.3	71.5	63.9
Property dispositions	(124.5)	(3.1)	(197.1)	(55.6)
Sub-total	(108.7)	4.2	(125.6)	8.3
Total net capital investment	**$ 38.3**	**$ 173.9**	**$ 336.2**	**$ 709.8**

Depletion, Depreciation and Amortization ("DD&A")

DD&A of property, plant and equipment is recognized using the unit-of-production method based on proved plus probable reserves. For the three and nine months ended September 30, 2013 DD&A increased to $138.8 million and $398.2 million respectively, compared to $132.8 million and $379.5 million during the same periods in 2012, primarily due to higher production.

Other Assets

Other assets consist of our portfolio of equity investments in other oil and gas companies. These investments are carried at their estimated fair value with changes in fair value recorded in other comprehensive income. The change in fair value of these investments for the three and nine months ended September 30, 2013 resulted in unrealized gains of $0.9 million and $4.8 million respectively, compared to unrealized losses of $17.4 million and $68.5 million for the same periods in 2012. The unrealized losses in the prior year related primarily to our investment in Laricina Energy Ltd. which we disposed of in the third quarter of 2012.

During the three and nine months ended September 30, 2013 we sold certain marketable securities for proceeds of $0.6 million and $2.5 million, respectively, recognizing gains of $0.2 million and $0.4 million. See Note 8 for further information.

Decommissioning Liabilities

In connection with our operations, we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total decommissioning liabilities 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 decommissioning liability to be $516.8 million at September 30, 2013 compared to $599.7 million at December 31, 2012. For the nine months ended September 30, 2013 there was a $82.9 million decrease in decommissioning liability resulting primarily from the change in the risk-free rate used to calculate the present value of the liability, which increased to 3.07% from 2.36% at December 31, 2012. See Note 10 for further information.

Taxes

Current Income Taxes

We recorded a current tax expense of $7.9 million for the nine months ended September 30, 2013 compared to a $2.3 million expense for the same period in 2012 as a result of higher U.S net income in 2013. Our current tax 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.

We continue to expect to pay U.S. cash taxes of approximately 3% of U.S. cash flow in 2013 and between 3-5% of U.S. cash flow in 2014 and 2015. We currently do not expect to pay material cash taxes in Canada until after 2016. These estimates may vary depending on numerous factors including commodity prices, capital spending, tax regulations and acquisition and disposition activity.

Deferred Income Taxes

We recorded a deferred tax expense of $39.3 million for the nine months ended September 30, 2013 compared to a recovery of $5.2 million for the same period in 2012. The increase in deferred income tax expense is due to higher net income in 2013.

Net Income

Net income for the third quarter of 2013 was $34.0 million or $0.17 per share compared to a net loss of $63.5 million or $0.32 per share for the third quarter of 2012. Net income for the nine months ended September 30, 2013 totaled $81.4 million or $0.41 per share compared to $3.0 million or $0.02 per share for the same period in 2012.

Oil and gas sales increased in 2013 due to higher production volumes and improvements in realized pricing. The combination of an increase in sales and no asset impairments during the current year led to higher earnings compared to the same periods in 2012, which were partially offset by higher mark-to-market losses on our commodity derivatives and lower asset disposition gains.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

The following tables provide a geographical analysis of key operating and financial results for the three and nine months ended September 30, 2013 and 2012.

	Three months ended September 30, 2013			Three months ended September 30, 2012		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	17,246	21,637	38,883	20,249	16,561	36,810
Natural gas liquids (bbls/day)	2,265	720	2,985	3,056	482	3,538
Natural gas (Mcf/day)	174,169	100,995	275,164	193,819	53,528	247,347
Total average daily production (BOE/day)	48,539	39,190	87,729	55,608	25,965	81,573
Pricing(1)						
Crude oil (per bbl)	$ 94.12	$ 98.04	$ 96.30	$ 74.42	$ 78.83	$ 76.41
Natural gas liquids (per bbl)	58.64	22.31	49.88	50.56	30.40	47.81
Natural gas (per Mcf)	2.62	3.55	2.96	1.94	3.14	2.20
Capital Expenditures						
Capital spending	$ 57.0	$ 88.8	$ 145.8	$ 48.4	$ 118.6	$ 167.0
Property and land acquisitions	6.4	9.4	15.8	–	7.3	7.3
Property dispositions	(89.3)	(35.2)	(124.5)	(3.0)	(0.1)	(3.1)
Revenues						
Oil and gas sales(1)	$ 204.1	$ 228.6	$ 432.7	$ 189.3	$ 135.6	$ 324.9
Royalties(2)	(33.0)	(63.1)	(96.1)	(28.0)	(36.6)	(64.6)
Commodity derivative instruments gain/(loss)	(55.7)	–	(55.7)	(40.8)	–	(40.8)
Expenses						
Operating	$ 62.4	$ 23.2	$ 85.6	$ 79.8	$ 14.7	$ 94.5
General and administrative	16.0	4.0	20.0	14.9	3.7	18.6
Equity based compensation	4.7	0.4	5.1	4.9	0.2	5.1
Depletion, depreciation and amortization	59.6	79.2	138.8	78.6	54.2	132.8
Impairment	–	–	–	47.9	65.9	113.8
Current income tax expense	(0.3)	5.5	5.2	0.2	(2.4)	(2.2)

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) U.S. royalties include state production tax.

(CDN$ millions, except per unit amounts)	Nine months ended September 30, 2013 Canada	U.S.	Total	Nine months ended September 30, 2012 Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	18,253	20,173	38,426	20,625	15,182	35,807
Natural gas liquids (bbls/day)	2,782	575	3,357	3,266	378	3,644
Natural gas (Mcf/day)	179,503	99,709	279,212	201,625	47,421	249,046
Total average daily production (BOE/day)	50,952	37,366	88,318	57,495	23,464	80,959
Pricing[1]						
Crude oil (per bbl)	$ 80.02	$ 91.50	$ 86.05	$ 76.28	$ 82.02	$ 78.72
Natural gas liquids (per bbl)	56.59	26.77	51.48	57.07	36.03	54.88
Natural gas (per Mcf)	2.97	3.78	3.26	1.99	2.98	2.18
Capital Expenditures						
Capital spending	$ 184.4	$ 274.0	$ 458.4	$ 205.2	$ 487.5	$ 692.7
Property and land acquisitions	44.0	27.5	71.5	13.8	50.1	63.9
Property dispositions	(154.5)	(42.6)	(197.1)	(33.7)	(21.9)	(55.6)
Revenues						
Oil and gas sales[1]	$ 589.4	$ 608.1	$ 1,197.5	$ 594.3	$ 384.0	$ 978.3
Royalties[2]	(89.8)	(162.3)	(252.1)	(92.4)	(101.4)	(193.8)
Commodity derivative instruments gain/(loss)	(52.1)	–	(52.1)	74.3	–	74.3
Expenses						
Operating	$ 192.3	$ 60.0	$ 252.3	$ 208.2	$ 38.9	$ 247.1
General and administrative	53.1	10.4	63.5	48.8	11.1	59.9
Equity based compensation	16.3	1.2	17.5	10.1	(0.1)	10.0
Depletion, depreciation and amortization	186.2	212.0	398.2	239.1	140.4	379.5
Impairment	–	–	–	134.8	65.9	200.7
Current income tax expense/(recovery)	(0.3)	8.2	7.9	0.1	2.2	2.3

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) U.S. royalties include state production tax.

QUARTERLY FINANCIAL INFORMATION

Oil and gas sales have increased in 2013 mainly due to growing crude oil production and increasing crude oil prices. During 2012 oil and gas sales were relatively flat as increasing production volumes were offset by lower realized commodity prices. During 2011 we saw higher crude oil prices and declining natural gas prices combined with lower production levels, which resulted in fluctuating oil and gas sales throughout the year.

Quarterly Financial Information (CDN$ millions, except per share amounts)	Oil and Gas Sales[1]	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2013				
Third Quarter	$ 432.7	$ 34.0	$ 0.17	$ 0.17
Second Quarter	398.6	52.6	0.26	0.26
First Quarter	366.2	(5.2)	(0.03)	(0.03)
Total	**$ 1,197.5**	**$ 81.4**	**$ 0.41**	**$ 0.41**
2012				
Fourth Quarter	$ 360.7	$ (158.7)	$ (0.80)	$ (0.80)
Third Quarter	324.9	(63.5)	(0.32)	(0.32)
Second Quarter	314.4	100.3	0.51	0.51
First Quarter	339.0	(33.8)	(0.18)	(0.18)
Total	**$ 1,339.0**	**$ (155.7)**	**$ (0.80)**	**$ (0.80)**
2011				
Fourth Quarter	$ 357.3	$ (299.4)	$ (1.66)	$ (1.65)
Third Quarter	312.9	111.3	0.62	0.62
Second Quarter	354.2	268.0	1.50	1.49
First Quarter	318.7	29.5	0.17	0.16
Total	**$ 1,343.1**	**$ 109.4**	**$ 0.61**	**$ 0.61**

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

LIQUIDITY AND CAPITAL RESOURCES

During the quarter we continued to improve our liquidity and strengthen our balance sheet. Our trailing 12 month debt to funds flow ratio decreased to 1.2x from 1.6x at the end of the second quarter of 2013, and we had approximately $815 million of undrawn credit capacity as at September 30, 2013.

Our adjusted payout ratio, which is calculated as dividends (net of our stock dividends and DRIP proceeds, as applicable) plus capital spending and office capital divided by funds flow, was 97% for the third quarter of 2013 and 103% for the first nine months of 2013, compared to 159% and 206% for the same periods in 2012. This improvement is a result of lower capital spending, higher funds flow as well as the reduction of our monthly dividend from $0.18 to $0.09 at the end of the second quarter of 2012.

Total debt (net of cash) at September 30, 2013 was $964.6 million compared to $1,064.4 million at December 31, 2012. This debt was comprised of $185.3 million of bank indebtedness and $797.6 million of senior notes, less $18.3 million in cash.

Our working capital deficiency at September 30, 2013, excluding deferred financial assets and credits, was $185.8 million compared to $167.2 million at December 31, 2012. We expect to finance our working capital deficiency through funds flow and our bank credit facility.

Our key leverage ratios are detailed below:

Financial Leverage and Coverage	September 30, 2013	December 31, 2012
Long-term debt to funds flow (12 month trailing)(1)	1.2 x	1.7 x
Funds flow to interest expense (12 month trailing)(2)	13.5 x	12.1 x
Long-term debt to long-term debt plus equity(1)	24%	26%

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

Subsequent to September 30, 2013, we extended our $1.0 billion bank credit facility by one year to October 31, 2016. Drawn and undrawn fees decreased 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 1.1%, for a combined rate of approximately 2.8%.

At September 30, 2013 we were in compliance with all covenants under our bank credit facility and 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.

Dividends

During the three and nine months ended September 30, 2013 we reported dividends of $54.4 million ($0.27/share) and $162.2 million ($0.81/share) respectively, of which $12.0 million and $33.5 million respectively, was non-cash and related to our Stock Dividend Program ("SDP"). We 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 at this time.

Our SDP allows shareholders to elect to receive their dividends in the form of shares instead of cash. Currently approximately 24% of our shareholders participate in the SDP, representing $4.3 million of dividends per month. As with our previous DRIP, the SDP will serve as a source of capital by allowing us to retain cash that would otherwise be paid out as dividends.

Shareholders' Capital

During the third quarter of 2013, a total of 1,605,000 shares were issued for $26.9 million pursuant to the SDP and stock option plan. A total of 604,000 shares were issued for $8.5 million under our former DRIP and stock option plan for the same period in 2012. For the nine months ended September 30, 2013, a total of 3,189,000 shares were issued for $48.4 million pursuant to the SDP and stock option plan, compared to 2,068,000 shares issued for $34.3 million during the same period in 2012 under the SDP, former DRIP and stock option plan. See Note 14 for further information.

We had 201,874,000 shares outstanding at September 30, 2013 compared to 197,936,000 shares outstanding at September 30, 2012 and 198,684,000 shares outstanding at December 31, 2012. The weighted average basic number of shares outstanding for the nine months ended September 30, 2013 was 200,002,000 (2012 – 194,753,000). At November 7, 2013 we had 202,142,000 shares outstanding.

CHANGE IN BASIS OF PREPARATION OF FINANCIAL STATEMENTS AND U.S. FILING STATUS

Based on preparing our consolidated financial statements under IFRS, we fail to qualify as a "foreign private issuer" under U.S. securities regulations as of January 1, 2014. This is a result of a test performed the last business day of the second quarter of 2013 whereby over 50% of the book value of our assets were located in the U.S. and over 50% of our common shares were held by U.S. residents. Therefore, in order to retain a U.S. filing status but as a "domestic" filer, we would be required to adopt U.S. Generally Accepted Accounting Principles ("US GAAP") for our 2013 year end reporting, which includes comparative periods for 2012 and 2011. These US GAAP financial statements would satisfy our Canadian filing obligations and IFRS statements would no longer be prepared.

We have prepared our comparative US GAAP statements, and under US GAAP less than 50% of the book value of our assets were located in the U.S. on the last business day of the second quarter of 2013. Ordinarily, an existing domestic filer could change to a foreign private issuer in that event. As a result, we are consulting with U.S. securities regulators on our ability to maintain our foreign private issuer status.

CHANGE IN APPOINTMENT OF INDEPENDENT RESERVES ENGINEER

During the third quarter we appointed Netherland, Sewell & Associates, Inc. to evaluate our reserves and contingent resources associated with our Marcellus interests for the year ended December 31, 2013.

2013 GUIDANCE

A summary of our 2013 guidance is below.

Summary of 2013 Expectations	Target
Average annual production	87,500 BOE/day (increase from 85,000 BOE/day)
Exit rate production	95,000 BOE/day (including the Marcellus acquisition)
Capital spending	$685 million
Production mix (volumes)	48% crude oil and liquids
Average royalty rate (% of gross sales, net of transportation)	21%
Operating costs	$10.70/BOE
G&A expenses – cash	$2.70/BOE
Equity based compensation expenses – cash	$0.60/BOE
Cash taxes (% of U.S. funds flow)	~3%
Average interest and financing costs	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 September 30, 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 July 1, 2013 and ending September 30, 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 2013 and 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; anticipated cash and non-cash G&A, equity based compensation and financing expenses; operating costs; capital spending levels in 2013 and its impact on our production level and land holdings; our ability to reallocate funds within our 2013 capital program; potential future asset impairments and reversals; the amount of our future abandonment and reclamation costs and decommissioning liabilities; 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, and use of proceeds from, future asset dispositions; the potential change of our status from "foreign private issuer" to U.S. domestic issuer as of January 1, 2014 and expected changes in our reporting related thereto; 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 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 the Annual 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.

Statements

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	September 30, 2013	December 31, 2012
Assets			
Current assets			
Cash		$ 18,311	$ 5,200
Accounts receivable		153,313	150,372
Deferred financial assets	15	17,352	54,165
Other current		16,676	15,068
		$ 205,652	$ 224,805
Exploration and evaluation assets	4	$ 817,575	$ 773,820
Property, plant and equipment	5	4,166,257	4,242,447
Goodwill		156,408	151,390
Deferred financial assets	15	13,938	8,013
Other assets	8	14,718	11,687
Total Assets		$ 5,374,548	$ 5,412,162
Liabilities			
Current liabilities			
Accounts payable		$ 308,791	$ 274,387
Dividends payable		18,169	17,882
Current portion of long-term debt	9	47,105	45,566
Deferred financial credits	15	39,822	18,522
		$ 413,887	$ 356,357
Long-term debt	9	$ 935,783	$ 1,023,999
Deferred financial credits	15	–	17,127
Deferred tax liability		416,305	365,473
Decommissioning liability	10	516,776	599,652
		$ 1,868,864	$ 2,006,251
Total Liabilities		$ 2,282,751	$ 2,362,608
Equity			
Shareholders' capital	14	$ 3,866,477	$ 3,818,043
Contributed surplus	14	41,030	36,088
Accumulated deficit		(817,556)	(736,761)
Accumulated other comprehensive income/(loss)		1,846	(67,816)
		$ 3,091,797	$ 3,049,554
Total Liabilities & Equity		$ 5,374,548	$ 5,412,162

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Income and Comprehensive Income

(CDN$ thousands) unaudited	Note	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Revenues					
Oil and gas sales		$ 441,503	$ 331,753	$ 1,219,755	$ 998,067
Royalties		(96,117)	(64,624)	(252,149)	(193,803)
Commodity derivative instruments gain/(loss)	15	(55,674)	(40,780)	(52,107)	74,276
		$ 289,712	$ 226,349	$ 915,499	$ 878,540
Expenses					
Operating		$ 85,548	$ 94,482	$ 252,265	$ 247,065
General and administrative		20,031	18,597	63,514	59,970
Equity based compensation	14	5,083	5,066	17,475	9,963
Transportation		8,830	6,815	22,259	19,775
Depletion, depreciation and amortization	5	138,766	132,780	398,181	379,515
Impairments	6	–	113,824	–	200,730
Foreign exchange loss/(gain)	12	(2,509)	(13,609)	4,027	(18,885)
Finance expense	11	18,518	18,923	55,430	52,129
Asset disposition gain	7	(30,669)	(47,782)	(26,403)	(71,726)
Other expense/(income)		(399)	207	99	(63)
		$ 243,199	$ 329,303	$ 786,847	$ 878,473
Income/(Loss) before taxes		$ 46,513	$ (102,954)	$ 128,652	$ 67
Current tax expense/(recovery)	13	5,235	(2,249)	7,943	2,299
Deferred tax expense/(recovery)	13	7,258	(37,239)	39,305	(5,209)
Net Income/(Loss)		$ 34,020	$ (63,466)	$ 81,404	$ 2,977
Other Comprehensive Income/(Loss)					
Change due to marketable securities (net of tax)	8				
Unrealized gains/(losses)		$ 924	$ (17,440)	$ 4,816	$ (68,517)
Realized gains reclassified to net income		(125)	(41,956)	(315)	(41,956)
Change in cumulative translation adjustment		(45,397)	(69,070)	65,161	(67,323)
Other Comprehensive Income/(Loss), net of tax		$ (44,598)	$ (128,466)	$ 69,662	$ (177,796)
Total Comprehensive Income/(Loss)		$ (10,578)	$ (191,932)	$ 151,066	$ (174,819)
Net income/(loss) per share					
Basic		$ 0.17	$ (0.32)	$ 0.41	$ 0.02
Diluted		$ 0.17	$ (0.32)	$ 0.41	$ 0.02
Weighted average number of shares outstanding (thousands)	14				
Basic		201,117	197,618	200,002	194,753
Diluted		202,338	197,618	200,415	194,944

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Changes in Shareholders' Equity

Nine months ended September 30 (CDN$ thousands) unaudited	**2013**	**2012**
Shareholders' Capital		
Balance, beginning of year	$ 3,818,043	$ 3,442,364
Public offering	–	330,618
Stock Option Plan – cash	12,723	1,180
Stock Option Plan – non cash	2,222	1,119
Dividend Reinvestment Plan	–	19,150
Stock Dividend Program	33,489	13,987
Balance, end of period	$ 3,866,477	$ 3,808,418
Contributed Surplus		
Balance, beginning of year	$ 36,088	$ 26,910
Stock Option Plan – exercised	(2,222)	(1,119)
Stock Option Plan – expensed	7,164	7,697
Balance, end of period	$ 41,030	$ 33,488
Accumulated Deficit		
Balance, beginning of year	$ (736,761)	$ (279,467)
Net income	81,404	2,977
Dividends to shareholders	(162,199)	(247,988)
Balance, end of period	$ (817,556)	$ (524,478)
Accumulated other comprehensive income		
Balance, beginning of year	$ (67,816)	$ 87,172
Changes due to marketable securities (net of tax)		
Unrealized gains/(losses)	4,816	(68,517)
Realized gains reclassified to net income	(315)	(41,956)
Change in cumulative translation adjustment	65,161	(67,323)
Balance, end of period	$ 1,846	$ (90,624)
Total Equity	$ 3,091,797	$ 3,226,804

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Operating Activities				
Net income/(loss)	$ 34,020	$ (63,466)	$ 81,404	$ 2,977
Non-cash items add/(deduct):				
Depletion, depreciation and amortization	138,766	132,780	398,181	379,515
Impairments	–	113,824	–	200,730
Change in fair value of derivative instruments	48,950	55,986	35,061	(83,400)
Deferred tax expense/(recovery)	7,258	(37,239)	39,305	(5,209)
Foreign exchange loss/(gain) on U.S. dollar debt and working capital	(7,446)	(25,370)	9,092	(15,815)
Accretion expense	3,432	3,356	10,254	10,324
Equity based compensation – Stock Option Plan	1,686	2,588	7,164	7,697
Amortization of debt transaction costs	190	303	1,420	1,097
Derivative settlement on senior note principal repayment	–	–	18,011	18,043
Asset disposition gain	(30,669)	(47,782)	(26,403)	(71,726)
Funds flow	$ 196,187	$ 134,980	$ 573,489	$ 444,233
Decommissioning expenditures	(3,701)	(3,396)	(10,036)	(14,406)
Changes in non-cash operating working capital	25,684	(12,138)	11,372	(84,144)
Cash flow from operating activities	$ 218,170	$ 119,446	$ 574,825	$ 345,683
Financing Activities				
Issuance of shares	$ 12,694	$ –	$ 12,723	$ 350,948
Cash dividends	(42,411)	(44,850)	(128,710)	(234,001)
Change in bank debt	(144,858)	(15,720)	(74,769)	(142,691)
Repayment of senior notes	–	–	(35,655)	(35,623)
Proceeds from senior note issue	–	–	–	406,088
Derivative settlement on senior note principal repayment	–	–	(18,011)	(18,043)
Changes in non-cash financing working capital	137	55	288	(14,794)
Cash flow from financing activities	$ (174,438)	$ (60,515)	$ (244,134)	$ 311,884
Investing Activities				
Capital expenditures	$ (146,997)	$ (169,752)	$ (461,835)	$ (701,495)
Property and land acquisitions	(15,792)	(7,277)	(71,451)	(63,946)
Property dispositions	124,462	3,112	197,086	25,636
Sale of equity investments	599	141,044	2,482	145,454
Changes in non-cash investing working capital	(145)	(37,238)	20,590	(71,498)
Cash flow from investing activities	$ (37,873)	$ (70,111)	$ (313,128)	$ (665,849)
Effect of exchange rate changes on cash	$ 1,696	$ 4,005	$ (4,452)	$ 2,653
Change in cash	$ 7,555	$ (7,175)	$ 13,111	$ (5,629)
Cash, beginning of period	10,756	7,175	5,200	5,629
Cash, end of period	$ 18,311	$ –	$ 18,311	$ –
Supplementary Cash Flow Information				
Cash income taxes paid/(received)	$ 3,487	$ –	$ (1,403)	$ 17,651
Cash interest paid	$ 2,630	$ 3,249	$ 31,851	$ 24,774

See accompanying notes to the Condensed Consolidated Financial Statements

Notes

Notes to Condensed Consolidated Financial Statements

(unaudited)

1. REPORTING ENTITY

These interim condensed consolidated financial statements ("interim Consolidated Financial Statements") and notes present the results of Enerplus Corporation including its Canadian and U.S. subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' head office is located in Calgary, Alberta, Canada. The interim Consolidated Financial Statements were authorized for issue by the Board of Directors on November 7, 2013.

2. BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") for the three and nine months ended September 30, 2013 and the 2012 comparative periods. They have been prepared in accordance with IAS 34, "Interim Financial Reporting". These interim Consolidated Financial Statements do not include all the necessary annual disclosures as prescribed by IFRS and should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2012. There have been no changes to the use of estimates or judgments since December 31, 2012.

3. SIGNIFICANT ACCOUNTING POLICIES

On January 1, 2013, Enerplus adopted the following new accounting standards that were issued by the IASB. The adoption of these standards did not have a material impact on Enerplus' interim Consolidated Financial Statements.

- IFRS 7 *Financial Instruments Disclosures*
- IFRS 10 *Consolidated Financial Statements*
- IFRS 11 *Joint Arrangements*
- IFRS 12 *Disclosure of Interests in Other Entities*
- IFRS 13 *Fair Value Measurement*
- IAS 27 *Consolidation and Separate Financial Statements*
- IAS 28 *Investments in Joint Ventures*

4. EXPLORATION AND EVALUATION ("E&E ASSETS")

Carrying value ($ thousands)	**E&E assets**
As at December 31, 2012	$ 773,820
Capital spending and acquisitions	102,271
Dispositions	(9,798)
Transfers to Property, Plant and Equipment	(64,565)
Foreign currency translation adjustment	15,847
As at September 30, 2013	**$ 817,575**

As at September 30, 2013 the E&E asset balance of $817,575,000 (December 31, 2012 – $773,820,000) consists of undeveloped lands and assets that management has not fully evaluated for technical feasibility and commercial viability.

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

Carrying value before accumulated depletion and depreciation ($ thousands)	**Developed and Producing ("D&P assets")**	**Office and other**	**Total**
As at December 31, 2012	$ 6,684,154	$ 82,588	$ 6,766,742
Capital spending and acquisitions	427,578	3,437	431,015
Transfers from E&E assets	64,565	–	64,565
Change in decommissioning costs (Note 10)	(77,693)	–	(77,693)
Dispositions	(239,310)	–	(239,310)
Foreign currency translation adjustment	84,188	364	84,552
As at September 30, 2013	**$ 6,943,482**	**$ 86,389**	**$ 7,029,871**

Accumulated depletion and depreciation	**D&P assets**	**Office and other**	**Total**
As at December 31, 2012	$ 2,463,903	$ 60,392	$ 2,524,295
Depletion and Depreciation	393,338	4,843	398,181
Dispositions	(71,560)	–	(71,560)
Foreign currency translation adjustment	12,576	122	12,698
As at September 30, 2013	**$ 2,798,257**	**$ 65,357**	**$ 2,863,614**

Net carrying value	**D&P assets**	**Office and other**	**Total**
As at December 31, 2012	$ 4,220,251	$ 22,196	$ 4,242,447
As at September 30, 2013	**$ 4,145,225**	**$ 21,032**	**$ 4,166,257**

6. IMPAIRMENT

During the three and nine months ended September 30, 2013 Enerplus did not record any impairments. For the same periods in 2012, impairment losses were $113,824,000 and $200,730,000 respectively.

7. ASSET DISPOSITION GAIN

	Three months ended September 30,		**Nine months ended September 30,**	
($ thousands)	**2013**	**2012**	**2013**	**2012**
Gain on property dispositions	$ (30,519)	$ –	$ (26,035)	$ (24,100)
Gain on sale of marketable securities	(150)	(47,782)	(368)	(47,626)
Total asset disposition gain	**$ (30,669)**	**$ (47,782)**	**$ (26,403)**	**$ (71,726)**

8. OTHER ASSETS

Other assets of $14,718,000 (December 31, 2012 – $11,687,000) represent Enerplus' marketable securities portfolio. During the nine months ended September 30, 2013 Enerplus sold certain marketable securities for proceeds of $2,482,000 recognizing a gain of $368,000. In connection with these sales, realized gains of $315,000 net of tax were reclassified from accumulated other comprehensive income to net income.

For the three and nine months ended September 30, 2013 the change in fair value of these investments represented unrealized gains of $924,000 ($1,058,000 before tax) and $4,816,000 ($5,514,000 before tax) respectively. For the same periods in 2012, the change in fair value of these investments represented unrealized losses of $17,440,000 ($19,967,000 before tax) and $68,517,000 ($78,449,000 before tax) respectively.

9. DEBT

($ thousands)	September 30, 2013	December 31, 2012
Current:		
Senior notes	$ 47,105	$ 45,566
	$ 47,105	$ 45,566
Long term:		
Bank credit facility	$ 185,327	$ 260,950
Senior notes	750,456	763,049
	$ 935,783	$ 1,023,999
Total debt	**$ 982,888**	**$ 1,069,565**

Senior Notes

The terms and rates of the Company's senior notes at September 30, 2013 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	20,570
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$355,000	365,118
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	41,140
June 18, 2009	June 18 and Dec 18	5 equal annual installments beginning June 18, 2017	7.97%	US$225,000	US$225,000	231,412
Oct 1, 2003	April 1 and Oct 1	5 equal annual installments beginning Oct 1, 2011	5.46%	US$54,000	US$32,400	33,323
June 19, 2002	June 19 and Dec 19	5 equal annual installments beginning June 19, 2010	6.62%	US$175,000	US$35,000	35,998
					Total Carrying Value	**$ 797,561**
					Current portion	**$ 47,105**
					Long term portion	**$ 750,456**

10. DECOMMISSIONING LIABILITY

Enerplus has estimated the net present value of its decommissioning liability to be $516,776,000 at September 30, 2013 compared to $599,652,000 at December 31, 2012, based on a total undiscounted liability of $731,378,000 and $659,714,000 respectively. The decommissioning liability was calculated using a risk free rate of 3.07% at September 30, 2013 (December 31, 2012 – 2.36%).

($ thousands)	Nine months ended September 30, 2013	Year ended December 31, 2012
Decommissioning liability, beginning of year	$ 599,652	$ 563,763
Change in estimates	(81,221)	69,822
Property acquisition and development activity	3,528	5,559
	$ (77,693)	$ 75,381
Dispositions	(6,629)	(33,584)
Decommissioning expenditures	(10,036)	(19,905)
Accretion	10,254	13,522
Foreign currency translation adjustment	1,228	475
Decommissioning liability, end of period	**$ 516,776**	**$ 599,652**

11. FINANCE EXPENSE

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2013	2012	2013	2012
Realized:				
Interest on bank debt and senior notes	$ 14,665	$ 14,864	$ 43,141	$ 39,140
Unrealized:				
Cross currency interest rate swap loss	273	756	1,093	2,488
Interest rate swap gain	(42)	(356)	(478)	(920)
Amortization of debt transaction costs	190	303	1,420	1,097
Accretion of decommissioning liability	3,432	3,356	10,254	10,324
Finance expense	**$ 18,518**	**$ 18,923**	**$ 55,430**	**$ 52,129**

12. FOREIGN EXCHANGE

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2013	2012	2013	2012
Realized:				
Foreign exchange loss	$ 59	$ 4,123	$ 17,658	$ 10,031
Unrealized:				
Translation of U.S. dollar debt and working capital	(7,446)	(25,370)	9,092	(15,815)
Cross currency interest rate swap (gain)/loss	939	2,505	(19,043)	(14,807)
Foreign exchange swap (gain)/loss	3,939	5,133	(3,680)	1,706
Foreign exchange (gain)/loss	**$ (2,509)**	**$ (13,609)**	**$ 4,027**	**$ (18,885)**

13. INCOME TAXES

($ thousands)	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Current tax expense/(recovery)				
Canada	$ (339)	$ 239	$ (258)	$ 116
U.S.	5,574	(2,488)	8,201	2,183
Total current tax expense/(recovery)	$ 5,235	$ (2,249)	$ 7,943	$ 2,299
Deferred tax expense/(recovery)	7,258	(37,239)	39,305	(5,209)
Total income tax expense/(recovery)	**$ 12,493**	**$ (39,488)**	**$ 47,248**	**$ (2,910)**

14. SHAREHOLDERS' CAPITAL

(a) Share Capital

	Nine months ended September 30, 2013		Year ended December 31, 2012	
Authorized unlimited number of common shares **Issued:** (thousands)	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	198,684	$ 3,818,043	181,159	$ 3,442,364
Issued for cash:				
Public offerings	–	–	14,709	330,618
Dividend reinvestment plan	–	–	955	19,150
Stock option plan	880	12,723	68	1,180
Non-cash:				
Stock dividend program	2,309	33,489	1,793	23,612
Stock option plan	–	2,222	–	1,119
Balance, end of period	**201,873**	**$ 3,866,477**	**198,684**	**$ 3,818,043**

(b) Dividends

($ thousands)	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Cash dividends	$ 42,411	$ 44,850	$ 128,710	$ 234,001
Stock dividends	11,994	8,544	33,489	13,987
Dividends to shareholders	**$ 54,405**	**$ 53,394**	**$ 162,199**	**$ 247,988**

(c) Equity based compensation

The following table summarizes Enerplus' equity based compensation expense:

($ thousands)	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Cash:				
Long term incentive plans expense	$ 4,869	$ 5,224	$ 14,074	$ 5,355
Non-Cash:				
Equity total return swap gain	(1,472)	(2,746)	(3,763)	(3,089)
Stock option plan expense	1,686	2,588	7,164	7,697
Equity based compensation expense	**$ 5,083**	**$ 5,066**	**$ 17,475**	**$ 9,963**

(i) Long-Term Incentive Plans

Enerplus' long-term incentive plans include its Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Director Share Unit ("DSU") plans. At September 30, 2013 the long-term incentive plans had a liability balance of $18,069,000 (December 31, 2012 – $13,316,000) which is included in accounts payable on the Consolidated Balance Sheet.

The following table summarizes the PSU, RSU and DSU activity for the nine months ended September 30, 2013:

(thousands of units)	PSUs	RSUs	DSUs
Units outstanding:			
Balance, beginning of year	605	963	35
Granted	369	460	78
Vested	(124)	(467)	(13)
Forfeited	(69)	(104)	–
Balance, end of period	**781**	**852**	**100**

(ii) Stock Option Plan

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

Weighted average for the period	Nine months ended September 30, 2013	Year ended December 31, 2012
Dividend yield(1)	8.0%	8.2%
Volatility(1)	27.80%	28.35%
Risk-free interest rate	1.51%	1.35%
Forfeiture rate	10.0%	10.0%
Expected life	4.5 years	4.5 years

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

The weighted average grant date fair value of options granted during the nine months ended September 30, 2013 was $1.31 (September 30, 2012 – $2.23). At September 30, 2013, 4,529,000 options were exercisable at a weighted average exercise price of $24.12 with a weighted average remaining contractual term of 4.0 years, giving an aggregate intrinsic value of $2,575,000 (September 30, 2012 – $nil). The weighted average share price during the nine months ended September 30, 2013 was $15.18.

For the nine months ended September 30, 2013, Enerplus expensed a total of $7,164,000 related to its stock option plan. The total unamortized fair value of outstanding options of $6,406,000 will be recognized in net income over the remaining vesting period. Activity for the periods is as follows:

	Nine months ended September 30, 2013		Year ended December 31, 2012	
	Number of Options (000's)	Weighted Average Exercise Price(1)	Number of Options (000's)	Weighted Average Exercise Price(1)
Options outstanding				
Balance, beginning of year	10,768	$ 22.11	5,098	$ 29.41
Granted	6,144	14.10	7,313	19.00
Exercised	(880)	14.46	(68)	17.35
Forfeited	(2,031)	22.51	(1,056)	24.92
Expired	–	–	(519)	44.67
Balance, end of period	**14,001**	**$ 19.06**	**10,768**	**$ 22.11**
Options exercisable at the end of period	**4,529**	**$ 24.12**	**2,558**	**$ 27.20**

(1) Exercise price reflects grant prices less any reduction in strike price for outstanding rights under the rights incentive plan.

The following tables summarize the Contributed Surplus activity for the nine months ended September 30, 2013 and the ending balances as at September 30, 2013:

($ thousands)	Nine months ended September 30, 2013	Year ended December 31, 2012
Balance, beginning of year	$ 36,088	$ 26,910
Stock Option Plan – exercised	(2,222)	(1,119)
Stock Option Plan – expensed	7,164	10,297
Balance, end of period	**$ 41,030**	**$ 36,088**

($ thousands)	September 30, 2013	December 31, 2012
Cancelled shares	$ 3,795	$ 3,795
Stock Option Plan	37,235	32,293
Balance, end of period	**$ 41,030**	**$ 36,088**

(d) Basic and Diluted Earnings Per Share

Net income/(loss) per share has been determined based on the following:

	Three months ended September 30,		Nine months ended September 30,	
(thousands of shares)	2013	2012	2013	2012
Weighted average shares	201,117	197,618	200,002	194,753
Dilutive impact of options	1,221	–	413	191
Diluted shares	**202,338**	**197,618**	**200,415**	**194,944**

15. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

(a) Carrying Value and Fair Value of Non-Derivative Financial Instruments

The carrying value of cash, accounts receivable, accounts payable, dividends payable and bank credit facilities approximated their fair value at September 30, 2013 and December 31, 2012 due to their short term nature. At September 30, 2013 the combined fair values of Enerplus' senior notes was $840,890,000 and the carrying value was $797,561,000 (December 31, 2012 – fair value of $896,871,000 and carrying value of $808,615,000). The fair value of the senior notes was estimated by discounting future interest and principal payments using available market information at the balance sheet date.

(b) Fair Value of Derivative Financial Instruments

Derivative instruments are recorded at their estimated fair value using observable market inputs, other than quoted prices, at the balance sheet date. The deferred financial assets and credits on the Consolidated Balance Sheets result from recording derivative financial instruments at fair value.

The following table summarizes the change in fair value for the three months ended September 30, 2013:

Deferred financial assets/(liabilities) ($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Equity Swaps	Commodity Derivative Instruments Oil	Commodity Derivative Instruments Gas	Total
Beginning of period	$ (42)	$ (15,000)	$ 15,208	$ 617	$ 2,703	$ 29,780	$ 7,152	$ 40,418
Change in fair value gain/(loss)	42(1)	(1,212)(2)	(3,939)(3)	(156)(4)	1,472(5)	(45,609)(6)	452(6)	(48,950)
End of period	**$ –**	**$ (16,212)**	**$ 11,269**	**$ 461**	**$ 4,175**	**$ (15,829)**	**$ 7,604**	**$ (8,532)**

(1) Recorded in finance expense.
(2) Recorded in foreign exchange expense (loss of $939) and finance expense (loss of $273).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in equity based compensation.
(6) Recorded in commodity derivative instruments (see below).

The following table summarizes the change in fair value for the nine months ended September 30, 2013:

Deferred financial assets/(liabilities) ($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Equity Swaps	Commodity Derivative Instruments Oil	Commodity Derivative Instruments Gas	Total
Beginning of period	$ (478)	$ (34,162)	$ 7,589	$ (853)	$ 412	$ 50,672	$ 3,349	$ 26,529
Change in fair value gain/(loss)	478(1)	17,950(2)	3,680(3)	1,314(4)	3,763(5)	(66,501)(6)	4,255(6)	(35,061)
End of period	**$ –**	**$ (16,212)**	**$ 11,269**	**$ 461**	**$ 4,175**	**$ (15,829)**	**$ 7,604**	**$ (8,532)**

(1) Recorded in finance expense.
(2) Recorded in foreign exchange expense (gain of $19,043) and finance expense (loss of $1,093).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in equity based compensation.
(6) Recorded in commodity derivative instruments (see below).

The following table summarizes the fair value as at September 30, 2013:

Balance Sheet Classification:	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swap	Equity Swap	Commodity Derivative Instruments Oil	Commodity Derivative Instruments Gas	Total
Assets:								
Current	$ –	$ 795	$ 157	$ 461	$ 1,349	$ 6,591	$ 7,999	$ 17,352
Long-term	–	–	11,112	–	2,826	–	–	13,938
Liabilities:								
Current	–	(17,007)	–	–	–	(22,420)	(395)	(39,822)
Total	**$ –**	**$ (16,212)**	**$ 11,269**	**$ 461**	**$ 4,175**	**$ (15,829)**	**$ 7,604**	**$ (8,532)**

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

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2013	2012	2013	2012
Change in fair value gain/(loss)	$ (45,157)	$ (48,694)	$ (62,246)	$ 71,948
Net realized cash gain/(loss)	(10,517)	7,914	10,139	2,328
Commodity derivative instruments gain/(loss)	**$ (55,674)**	**$ (40,780)**	**$ (52,107)**	**$ 74,276**

(c) Risk Management

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 considered appropriate subject to a maximum of 80% of forecasted production volumes net of royalties.

The following tables summarize Enerplus' price risk management positions at October 22, 2013:

Crude Oil Instruments:

Instrument Type	bbls/day	US$/bbl(1)
Oct 1, 2013 – Dec 31, 2013		
WTI Swap	22,500	100.36
WTI Purchased Call	3,500	104.09
WTI Sold Put	5,500	63.09
WTI Sold Call	3,500	130.00
Brent – WTI Spread	5,000	7.09
WCS Differential Swap	2,000	(21.56)
MSW Differential Swap	500	(5.90)
Jan 1, 2014 – Jun 30, 2014		
WTI Swap	20,000	93.70
Brent – WTI Spread	3,000	93.10%
WCS Differential Swap	1,000	(23.25)
Jul 1, 2014 – Dec 31, 2014		
WTI Swap	15,000	92.73
Brent – WTI Ratio Spread	3,000	93.10%
WCS Differential Swap	1,000	(23.25)
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
Oct 1, 2013 – Dec 31, 2013			
AECO Swap	28.4	3.61	
AECO Purchased Put	22.7	3.17	
Jan 1, 2014 – Dec 31, 2014			
AECO Swap	4.7	3.96	
Oct 1, 2013 – Dec 31, 2013			
NYMEX Swap	15.0		3.85
Jan 1, 2014 – Dec 31, 2014			
NYMEX Swap	50.0		4.17

Electricity Instruments:

Instrument Type	MWh	CDN$/MWh
Oct 1, 2013 – Dec 31, 2013		
AESO Power Swap(1)	12.0	63.81
Jan 1, 2014 – Dec 31, 2014		
AESO Power Swap(1)	12.0	53.69
Jan 1, 2015 – Dec 31, 2015		
AESO Power Swap(1)	6.0	50.38

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

16. COMMITMENTS

During the three months ended September 30, 2013 Enerplus entered into a 7 year gathering contract that results in an annual minimum commitment of approximately $6,547,000 or $45,829,000 in total.

17. SUBSEQUENT EVENTS

Subsequent to September 30, 2013 Enerplus entered into the following acquisition and disposition agreements, subject to customary closing conditions:

a) Sale of non-core Canadian oil production for approximately $105 million;

b) Sale of undeveloped Montney acreage for approximately $130 million; and

c) Purchase of additional Marcellus working interests and undeveloped acreage for approximately US$153 million.

BOARD OF DIRECTORS

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The Woodlands, Texas

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Ian C. Dundas
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Enerplus Corporation
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Calgary, Alberta

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President
Fairway Resources, Inc.
Calgary, Alberta

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Calgary, Alberta

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Boerne, Texas

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

Sheldon B. Steeves[(5)(7)]
Corporate Director
Calgary, Alberta

OFFICERS

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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

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

Jodine J. Jenson Labrie
Vice President, Finance

H. Gordon Love
Vice President, Technical & Operations Services

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

Edward L. McLaughlin
President, Enerplus Resources (USA) Corporation

Christopher M. Stephens
Vice President, Canadian Assets

P. Scott Walsh
Vice President, Information Systems

Kenneth W. Young
Vice President, Land

Michael R. Politeski
Treasurer & Corporate Controller

(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

CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS CORPORATION

Enerplus Resources (USA) Corporation

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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.
D&P	developed and producing
E&E	exploration and evaluation
IFRS	International Financial Reporting Standards
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
MWh	megawatt hour(s) of electricity
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange, the benchmark for North American natural gas pricing
OCI	other comprehensive income
SDP	stock dividend program
WCS	Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing purposes
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

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